STP UNITS 3 and 4 COL DEIS
WEB REFERENCES
CHAPTER 9
PART 3

TCEQ 2009a Water Rights Database through Wade 2008 Groundwater Availability Modeling Section (end).

Please see Part 1 (in this ADAMS package) of these web references for Benson and Arnold 2001 Texas Bird Atlas through NETL 2007 Cost Performance Baseline for Fossil Fuel Plants.

Please see Part 2 (in this ADAMS package) of these web references for NextEra 2009 Solar Electric Generating Systems through TCEQ 2008 Texas Water Quality Inventory.

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

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BACK TO: Water Rights Permits: Getting Permission to Use Surface Water

Questions or Comments: wras@tceq.state.tx.us

Water Rights Database and Related Files

RELATED LINKS:

Water Rights Permitting and Availability

The Water Rights database contains data from all active and inactive surface water rights permits and water supply contracts. It is updated once each month. For an explanation of the data, please open the "Data Dictionary" and the "Metadata" documents. Further questions about this database should be directed to the Data branch of the Water Rights Team at (512) 239-4691.

- Water Rights Database File
  -unzips two Excel files, one containing all of the active water rights (wractive.xls), and the other containing all of the inactive water rights (wrinactive.xls).

- Data Dictionary (Word or PDF)- defines each field used in the database.
- Metadata (Word or PDF)- describes the database in terms of what data is collected, why the data is collected, and how the data is collected.
- (Help with Downloading Files.) (Help with PDF Files.)

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Questions or Comments:
wras@tceq.state.tx.us

Water Availability Models

Maps of water availability in the river basins of Texas. Water availability model and river basin input files. Executable files for running the water availability models.

Background

What is a water availability model?

A water availability model is a computer-based simulation predicting the amount of water that would be in a river or stream under a specified set of conditions.

The model of a specific river basin consists of two parts:

- the modeling program, called "WRAP", short for Water Rights Analysis Package
- a text file that contains basin-specific information for WRAP to process (these text files are called input files)

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How are these models used?

Water Availability Models are used to determine whether water would be available for a newly requested water right or amendment.

TCEQ staff uses two models in evaluating applications:

- the **Full Authorizaton** simulation, in which all water rights utilize their maximum authorized amounts, is used to evaluate applications for perpetual water rights and amendments.
- the **Current Conditions** simulation, which includes return flows, is used to evaluate applications for term water rights and amendments.

If water is available, these models estimate how often the applicant could count on water under various conditions. For example, would water be available only one month out of the year, half the year, or all year? And would that water be available in a repeat of the drought of record?

In evaluating applications for a new appropriation of water and some applications for amendments to existing water rights, TCEQ staff must consider recommended environmental flow needs. Environmental flow needs include instream flows and freshwater inflows to bays and estuaries.

The water availability models provide information that assists TCEQ staff in determining whether to recommend the granting or denial of an application.

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Water Availability by River Basin

What are general water availability maps?

These maps are generated from WAM output for both of the permitting runs (Full Authorization and Current Conditions) for each basin. The maps generally indicate the percentage of months during the period of record that unappropriated water is available at various locations in each basin.

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How are general water availability maps used?

The water availability maps can be used as a general indicator to see if water would be available with sufficient frequency to consider submitting a new application or an amendment to an existing water right. The availability of storage, the total amount requested, the type of use, environmental flow needs and other factors could affect the availability of unappropriated water for a particular project.

In using these maps, please keep these points in mind:

- The maps do not show how much water is present at any given point. If the river is always full but every drop is appropriated, the map will be red, showing that no water is available.
- The maps do not show how much water is available. They show only how often some water is available.
- Each map is valid as of the date shown on the map. New water rights or amendments to existing water rights may have been approved since the maps were created.
- The State Wide Availability Maps provides a very general look at water availability for the entire state. To look at water availability in a specific basin, use the main specific maps.

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General Water Availability Maps by River Basin

Of the twenty three river basins in Texas, maps are available for the following:

- Canadian River Basin Availability Maps
- Red River Basin Availability Maps
- Sulphur River Basin Availability Maps
- Cypress River Basin Availability Maps
- Sabine River Basin Availability Maps
- Neches River Basin Availability Maps
- Neches-Trinity Coastal Basin Availability Maps
- Trinity River Basin Availability Maps
- Trinity-San Jancinto Coastal Basin Availability Maps
- San Jacinto River Basin Availability Maps
- San Jacinto-Brazos River Basin Availability Maps
- Brazos River Basin Availability Maps
- Colorado River Basin Availability Maps
- Colorado-Lavaca Coastal Basin Availability Maps
- Lavaca River Basin Availability Maps
- Lavaca-Guadalupe Coastal Basin Availability Maps
- Guadalupe River Basin
- San Antonio River Basin
- San Antonio-Nueces Coastal Basin Availability Maps
- Nueces River Basin Availability Maps
- Nueces-Rio Grande Coastal Basin Availability Maps
- State Wide Availability Maps

Other maps will be posted here as they become available.

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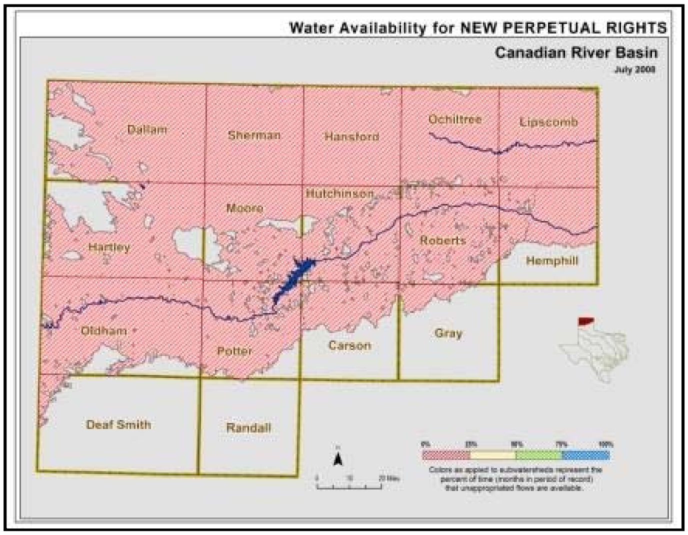
Canadian River Basin Availability Maps

Click on Images to see full-size maps



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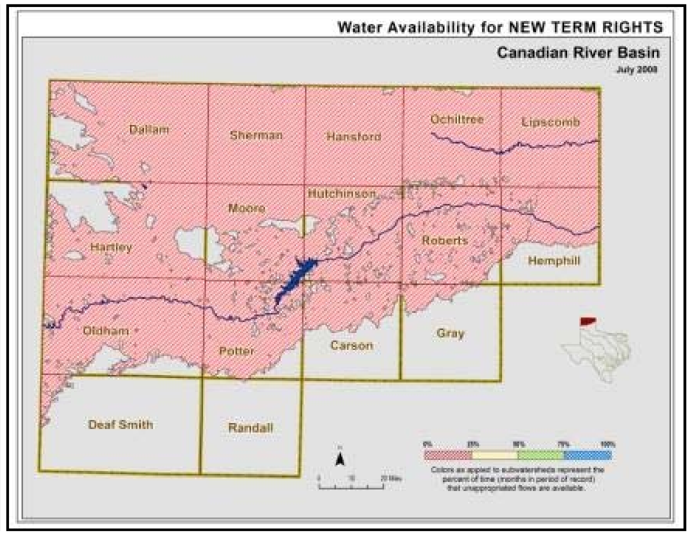

Current Conditions

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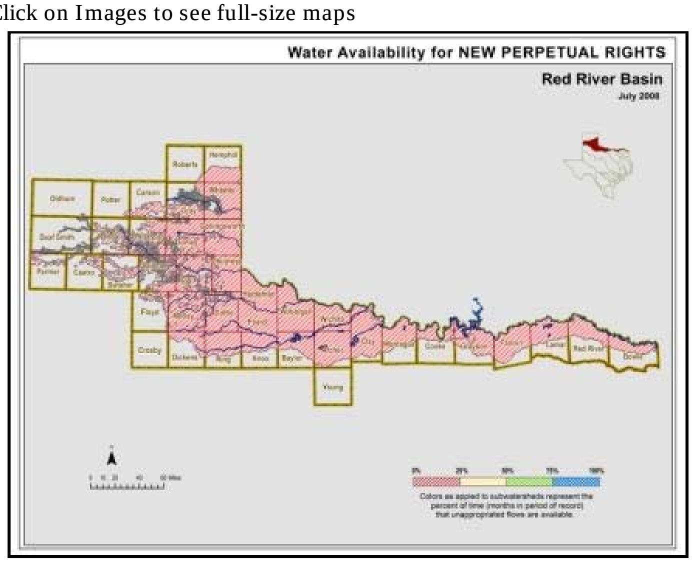
Red River Basin Availability Maps

Click on Images to see full-size maps



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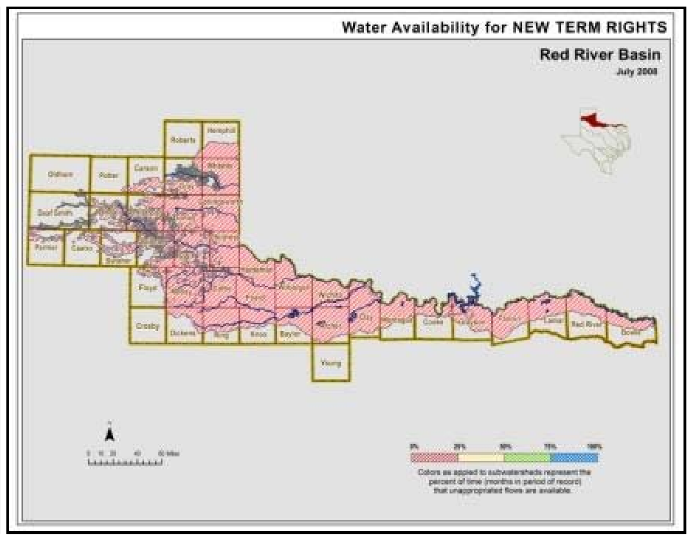

Current Conditions

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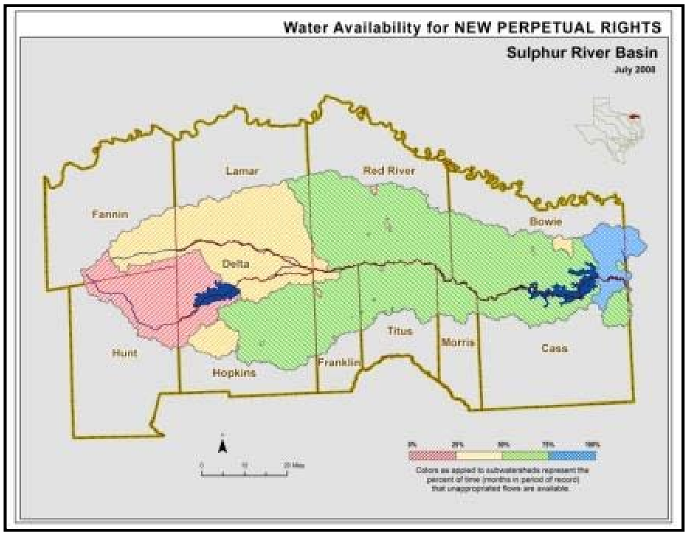
Sulphur River Basin Availability Maps

Click on Images to see full-size maps



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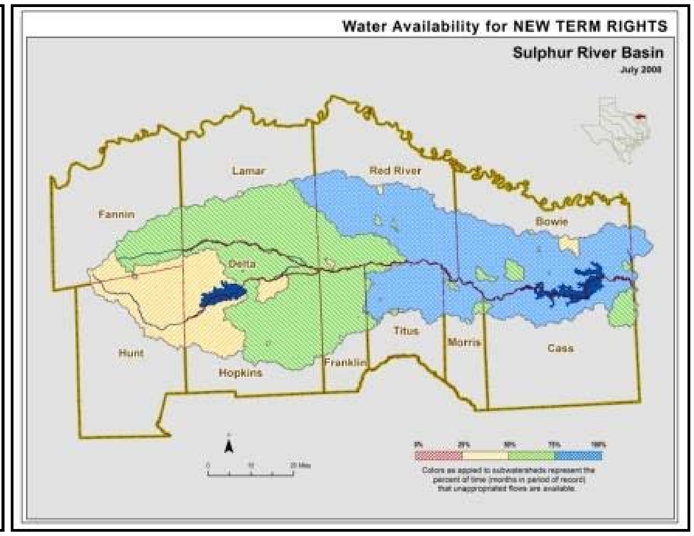

Current Conditions

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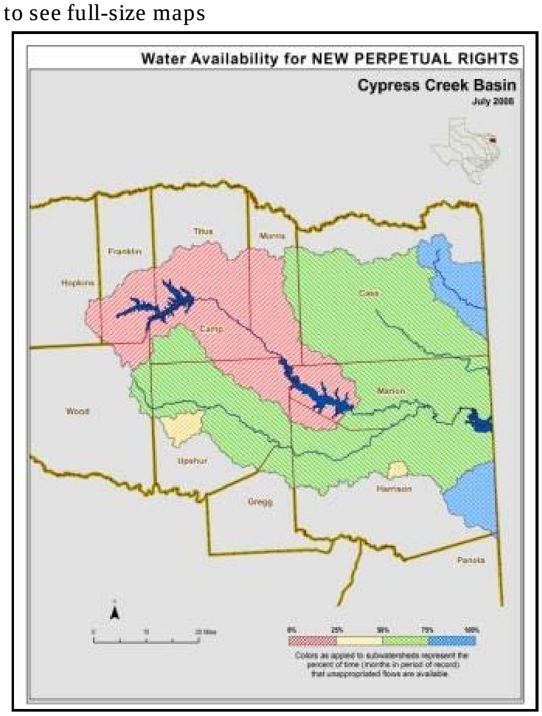
Cypress River Basin Availability Maps

Click on Images to see full-size maps



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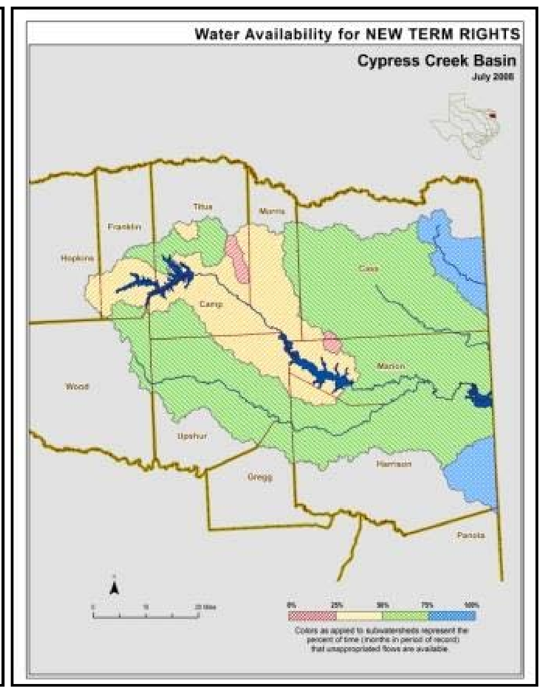

Current Conditions

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Sabine River Basin Availability Maps

Click on Images to see full-size maps

Full Authorization

Current Conditions

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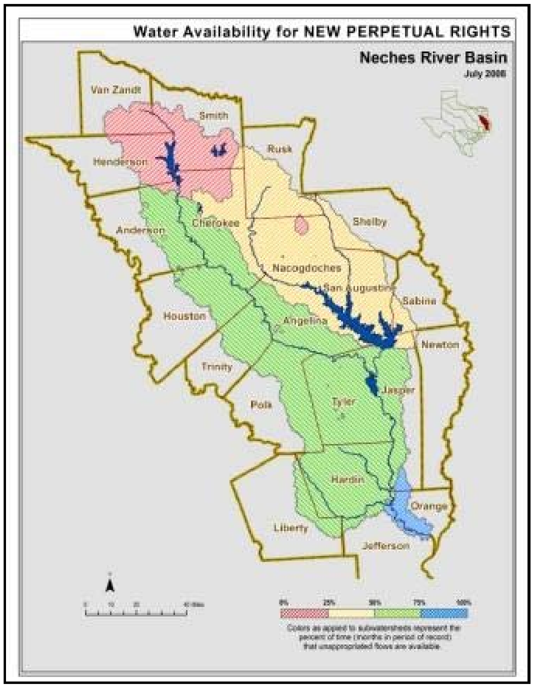
Neches River Basin Availability Maps

Click on Images to see full-size maps



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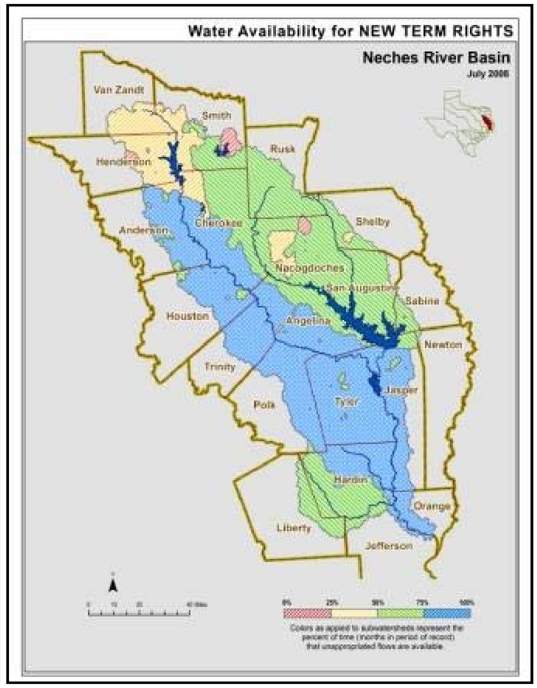

Current Conditions

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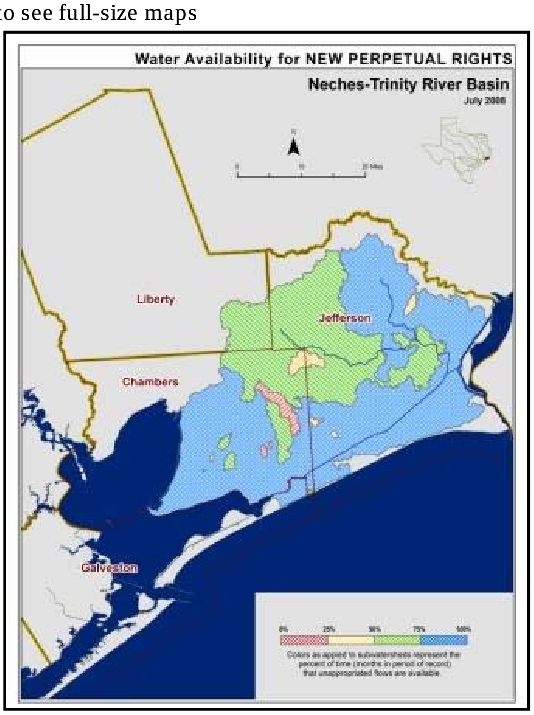
Neches-Trinity Coastal Basin Availability Maps

Click on Images to see full-size maps



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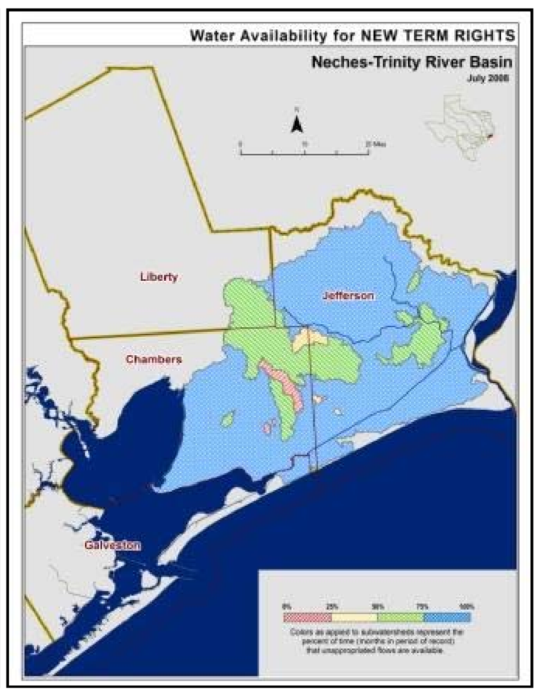

Current Conditions

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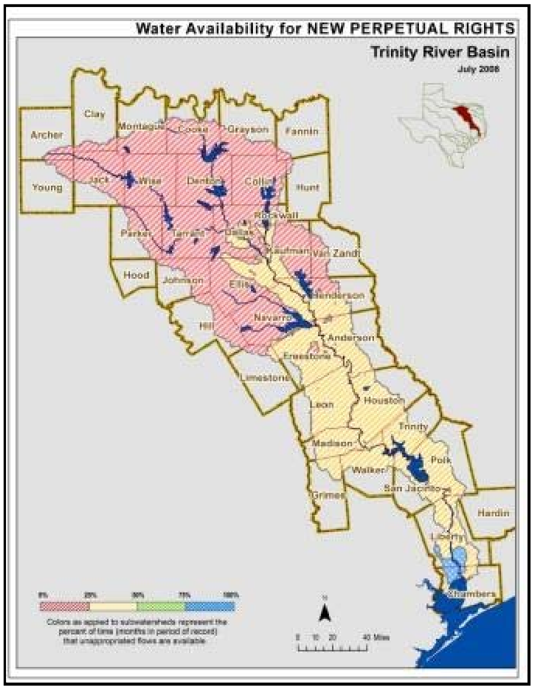
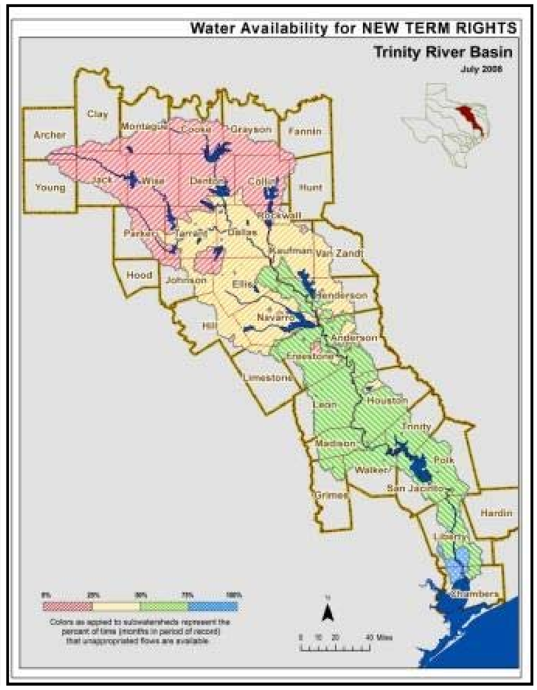
Trinity River Basin Availability Maps

Click on Images to see full-size maps





Full Authorization Current Conditions

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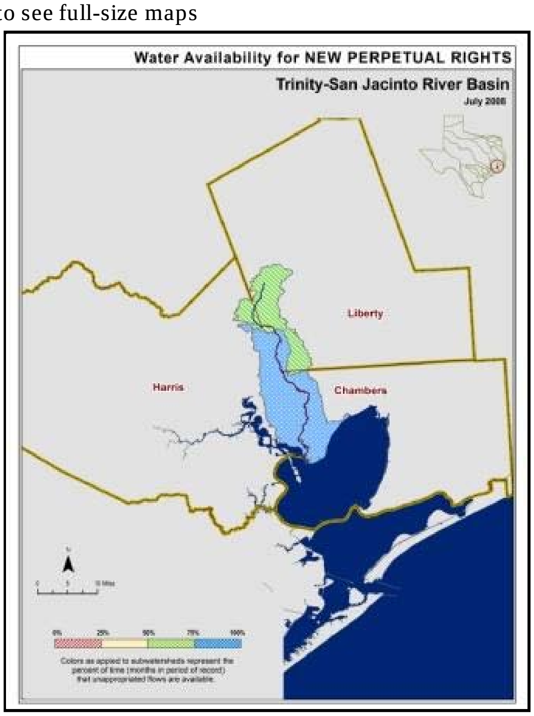
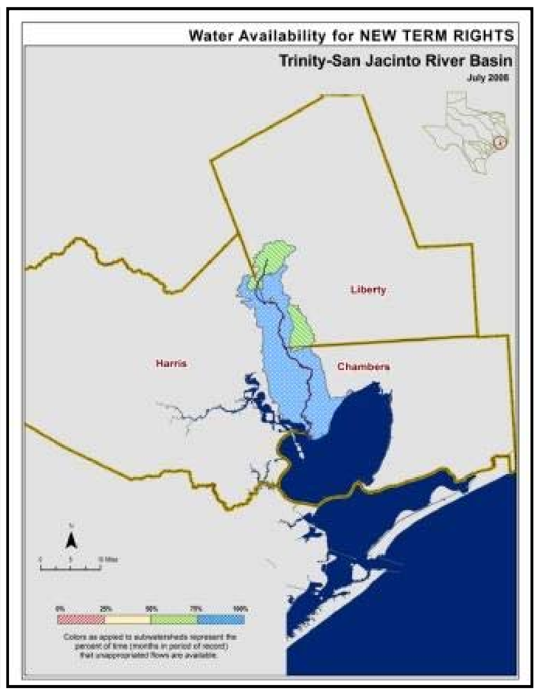
Trinity-San Jacinto Coastal Basin Availability Maps

Click on Images to see full-size maps





Full Authorization Current Conditions

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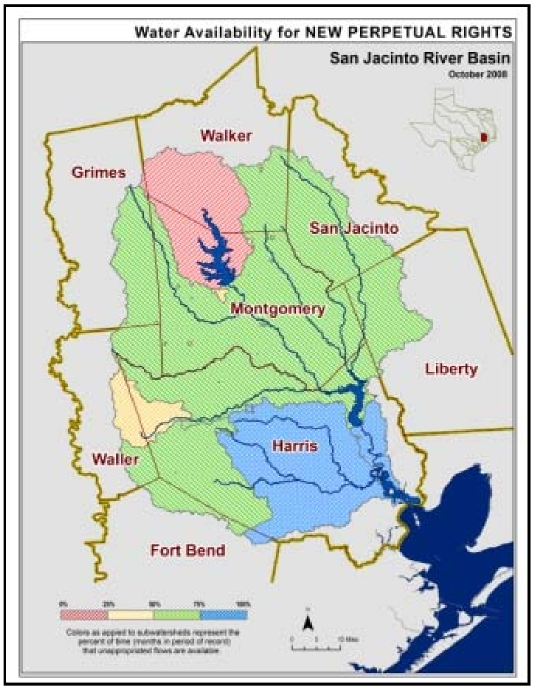
San Jacinto River Basin Availability Maps

Click on Images to see full-size maps

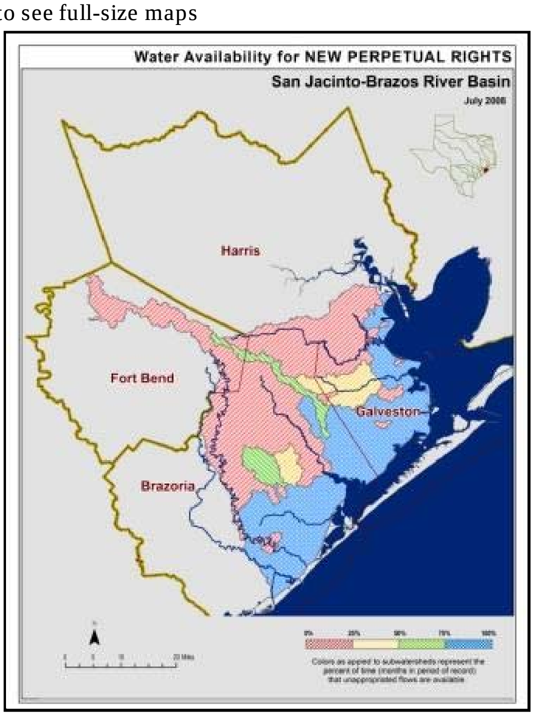


Full Authorization

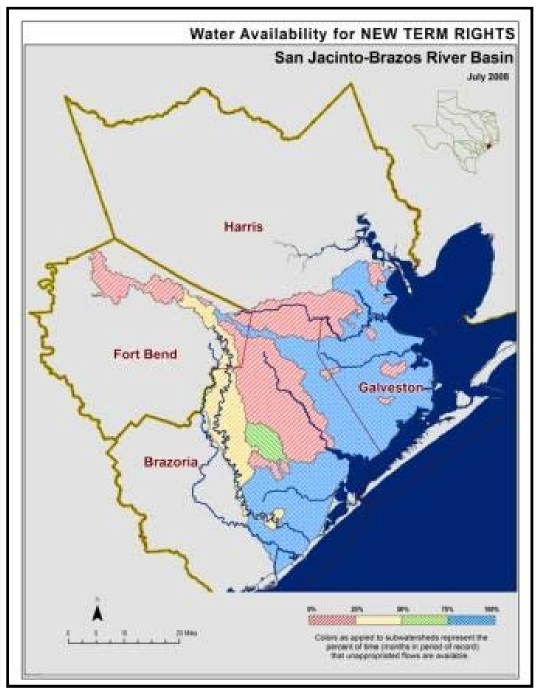
Current Conditions

San Jacinto-Brazos Coastal Basin Availability Maps

Click on Images to see full-size maps



Full Authorization



Current Conditions

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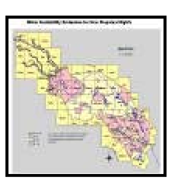
Brazos River Basin Availability Maps

Click on Images to see full-size maps



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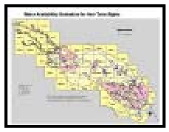

Current Conditions

Full Authorization

Current Conditions

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Colorado River Basin Availability Maps

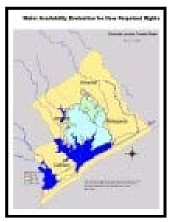
Click on Images to see full-size maps

Full Authorization

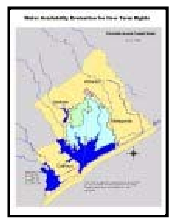
Current Conditions

Colorado-Lavaca Coastal Basin Availability Maps

Click on Images to see full-size maps



Full Authorization

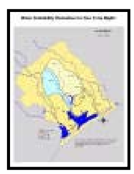


Current Conditions

Lavaca River Basin Availability Maps

Click on Images to see full-size maps

Full Authorization



Current Conditions

Lavaca-Guadalupe Coastal Basin Availability Maps

Click on Images to see full-size maps

Full Authorization

Current Conditions

Guadalupe River Basin

Click on Images to see full-size maps

Full Authorization

Current Conditions

San Antonio River Basin

Click on Images to see full-size maps


Full Authorization


Current Conditions

San Antonio-Nueces Coastal Basin Availability Maps

Click on Images to see full-size maps


Full Authorization


Current Conditions

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Nueces River Basin Availability Maps

Click on Images to see full-size maps


Full Authorization


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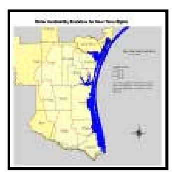
Nueces-Rio Grande Coastal Basin Availability Maps

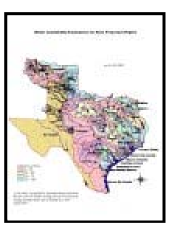
Click on Images to see full-size maps

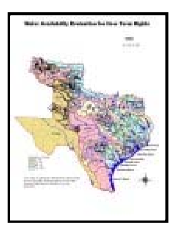

Full Authorization


Current Conditions

State Wide Availability Maps

Click on Images to see full-size maps


Full Authorization


Current Conditions

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WRAP: The Modeling Program

All river basin models are compatible with the March 2003 version of WRAP. The TX-WRAP, Tables, and WinWRAP files are compressed in executable (.EXE) format (Help with Downloading Files.)

- WRAP Manual
- Modifications

    - August 2003
    - March 2003
    - January 2003
- TX-WRAP (May 2004 version)
- Tables (May 2004 version)
- WinWRAP (September 2003 version)

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Input Files by River Basin

Data files necessary to run the water availability model for the following river basins are available as compressed files in "ZIP" format (Help with Downloading Files.)

Data for the TCEQ permitting runs (Full Authorization and Current Conditions) is available. In addition to the basin specific files needed to run the models, a text file is included in the ZIP file for each permitting run that details recent changes to the input files.

If you need more information, please contact: The Water Rights Permitting & Surface Water Availability Team at 512/239-4691 or send an email to: wras@tceq.state.tx.us

It should be noted that the basin input files are dated and the information can change as new and amended water rights are added to the models.

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Canadian River Basin

- Input data for Full Authorization
- Input data for Current Conditions

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Red River Basin

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Sulphur River Basin

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Cypress River Basin

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Sabine River Basin

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Neches River Basin

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Neches-Trinity Coastal Basin

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- Input data for Current Conditions

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Trinity River Basin

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- Input data for Current Conditions

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Trinity-San Jacinto Coastal Basin

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- Input data for Current Conditions

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San Jacinto River Basin

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- Input data for Current Conditions

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Brazos River Basin and San Jacinto-Brazos Coastal Basin

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- Input data for Current Conditions

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Colorado River Basin and Brazos-Colorado Coastal Basin

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- Input data for Current Conditions

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Colorado-Lavaca Coastal Basin

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Lavaca River Basin

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Lavaca-Guadalupe Coastal Basin

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Guadalupe River Basin and San Antonio River Basin

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San Antonio-Nueces Coastal Basin

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Nueces River Basin

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- Input data for Current Conditions

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Nueces-Rio Grande Coastal Basin

- Input data for Full Authorization
  - Lower
  - Upper
- Input data for Current Authorization
  - Lower
  - Upper

Rio Grande Basin

- Input data for Full Authorization
- Input data for Current Conditions

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Related content

- Water Right Permit Applications

Last Modified Thu, 24 Sep 2009
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Red River Compact Commission

Description of the Red River Compact Commission. Function of the Red River Compact Commission. Name of the appointed commissioner and contact information. Name of the TCEQ Interstate Compact Coordinator and contact information. Name and contact information of the legal counsel assigned to the Red River Compact Commission by the Texas Attorney General's Office. Dates of the annual meeting.

Objective

The Red River Compact Commission administers the Red River Compact to ensure that Texas receives its equitable share of quality water from the Red River and its tributaries as apportioned by the Compact. The Compact includes the states of Oklahoma, Arkansas, Louisiana, and Texas.

Strategic Plan and Compact with Texans

Statute

Chapter 46 Texas Water Code

Commissioners

Honorable William A. Abney
Red River Compact Commissioner
PO Box 1386
Marshall, TX 75671
Telephone: 903-938-6611
Fax: 903-938-4572
Term expires: Feb. 1, 2011
E-mail: waabney@internetwork.net

Honorable Mark R. Vickery
Red River Compact Commissioner, MC-109
PO Box 13087
Austin, TX 78711-3087
Telephone: 512-239-3900
Fax: 512-239-3939
Term expires: Term same as TCEQ executive director
E-mail: mvickery@tceq.state.tx.us

Advisors

Technical: Herman Settemeyer, MC-160
TCEQ
PO Box 13087
Austin, TX 78711
Phone: 512-239-4707
Fax: 512-239-4770
E-mail: hsetteme@tceq.state.tx.us

Legal: Jane Atwood

Office of the Attorney General
PO Box 12548
Austin, TX 78711
512-463-2012
512-320-0052
E-mail: jane.atwood@oag.state.tx.us

Meeting Dates

The annual meeting of the Red River Compact Commission will be held on April 27, 2010, in Arkansas. The specific location and time for the meeting will be posted at a later date.

Information Links

U.S. Geological Survey Exit...

Official Web Site of the Red River Compact Commission Exit...

Related content

- Pecos River Compact Commission
- What Are the Interstate River Compact Commissions?
- Canadian River Compact Commission
- Rio Grande Compact Commission
- Sabine River Compact Commission

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TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

›› Questions or Comments

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02/04/2010 --------------AirPermits IMS - PROJECT RECORD ---

Company Name: **MYPOWER CORP**
Central Registry Id : **CN603437971**

Region: **WACO** Account: Central Registry Id: **RN105672802**
County Name: **FREESTONE** City: **FAIRFIELD**
Location :

PROJECT INFORMATION

Project Administrative Name: **ELECTRIC POWER GENERATION FACILITY**
Project Technical Name: **ELECTRIC POWER GENERATION FACILITY**

Project Number: **143623** Permit Number: **PSDTX1200** Stdx/Pbr Number:
Project Received Date: **12/29/2008** Renewal Date: Issued Date:

Project Type: **INITIAL** Permit Type: **PREVENTION OF SIGNIFICANT DETERIORATION PERMIT**
Project Status: **PENDING**

Assigned Staff:
REVIEW ENG: HENDRICKSON , ERIK **REVIEWR1_2: HICKMAN , SHARON**
Staff Group:
AP INITIAL REVIEW **COMB/COAT SECTION**

FEE

Reference	Fee Receipt Number	Amount	Fee Receipt Date	Fee Payment Type

TRACKING ELEMENTS

TE Name	Start Date	Complete Date
PUBLIC NOTICE COMMENT PERIOD (NSR 1ST NOTICE)	**01/29/2009**	**03/02/2009**
APIRT TRANSFERRED PROJECT TO TECHNICAL STAFF (DATE)	**01/16/2009**	
LEGISLATORS NOTIFIED OF APPLICATION RECEIVED (DATE)	**01/16/2009**	
PROJECT DECLARED ADMIN COMPLETE (DATE)	**01/16/2009**	
PUBLIC NOTICE DRAFT SENT TO COMPANY (DATE)	**01/14/2009**	
SITE REVIEW RFC SENT TO REGION (DATE)	**01/13/2009**	
CENTRAL REGISTRY UPDATED	**01/13/2009**	**01/13/2009**
APIRT RECEIVED PROJECT (DATE)	**12/29/2008**	

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Executive Director's Marked Agenda

New Source Review Permits and Authorizations for Calendar Year 2009

Data updated: 12/02/2009

Project Description	Permit Number	County Name	Date Signed
Applicant Name			
TRUE COOPERATIVE GIN COMPANY			
Permit Renewal	41603	NUECES	11/30/2009
KNIGHT STONE LLC			
Change of Location	70551L002	WILLIAMSON	11/24/2009
FILM-PAK INC			
Permit Renewal	9457	TARRANT	11/24/2009
MARTIN MARIETTA MATERIALS SOUTHWEST INC			
Permit Renewal	41849	MEDINA	11/23/2009
WILSONART INTERNATIONAL INC			
Permit Renewal	41168	BELL	11/23/2009
NATIONAL OILWELL VARCO LP			
Permit Amendment	41801	HARRIS	11/19/2009
IRONHORSE ASPHALT LTD			
Permit Renewal	40172	BELL	11/19/2009
SEALY OIL MILL & FEED CO			
New Permit	88713	AUSTIN	11/19/2009
PEARCE FOUNDRY WEST INC			
Permit Renewal	8340A	HALL	11/17/2009
ALAMO CONCRETE PRODUCTS LTD			
Special Permit Renewal	19289	WHARTON	11/17/2009

KIEWIT TEXAS CONSTRUCTION LP			
Permit Renewal	**21727E**	**TERRY**	**11/17/2009**
TOWER TECH SYSTEMS INC			
Permit Amendment	**86078**	**TAYLOR**	**11/17/2009**
CONOCOPHILLIPS COMPANY			
Permit Renewal	**43073**	**HUTCHINSON**	**11/17/2009**
THE UNIVERSITY OF TEXAS AT AUSTIN			
Permit Renewal	**9322**	**TRAVIS**	**11/17/2009**
FARMERS GIN & GRAIN CO			
Permit Renewal	**41419**	**HILL**	**11/16/2009**
CARGILL MEAT SOLUTIONS CORPORATION			
Permit Amendment	**4844**	**HALE**	**11/12/2009**
STRIKE CONSTRUCTION LLC			
Permit Renewal	**40234**	**NUECES**	**11/10/2009**
BARTEN INDUSTRIAL COATINGS LLC			
New Permit	**87396**	**COLORADO**	**11/10/2009**
TRIPLE S MATERIALS L P			
Permit Renewal	**41930**	**NUECES**	**11/10/2009**
TIN INC			
Permit Renewal	**1037**	**SABINE**	**11/10/2009**
ARMOR MATERIALS INC			
Permit Renewal	**35732**	**SMITH**	**11/09/2009**
MOBIL CHEMICAL COMPANY INC			
Permit Renewal	**8758**	**JEFFERSON**	**11/09/2009**
E R CARPENTER LP			
New Permit	**84054**	**DALLAS**	**11/04/2009**
KEMIN INDUSTRIES INC			
New Permit	**84478**	**GALVESTON**	**11/03/2009**

LF MANUFACTURING INC			
Permit Renewal	**56268**	**LEE**	**11/03/2009**
LF MANUFACTURING INC			
Permit Renewal	**25301**	**LEE**	**11/03/2009**
HELENA CHEMICAL COMPANY			
New Permit	**88408**	**PALO PINTO**	**11/02/2009**
TXI OPERATIONS LP			
New Permit	**89562L001**	**COOKE**	**11/02/2009**
HILLIARD DOZER LP			
New Permit	**89989L001**	**BELL**	**11/02/2009**
EXXONMOBIL OIL CORPORATION			
Permit Renewal	**7799**	**JEFFERSON**	**10/27/2009**
PASADENA REFINING SYSTEM INC			
New Permit	**80804**	**HARRIS**	**10/26/2009**
ASPEN POWER LLC			
New Permit	**81706**	**ANGELINA**	**10/26/2009**
ASPEN POWER LLC			
New HAP Permit	**HAP12**	**ANGELINA**	**10/26/2009**
LBC HOUSTON LP			
Permit Amendment	**3467B**	**HARRIS**	**10/26/2009**
LBC HOUSTON LP			
New NA Permit	**N99**	**HARRIS**	**10/26/2009**
HOLMES FOODS INC			
Permit Renewal	**41776**	**GONZALES**	**10/26/2009**
GULBRANDSEN TECHNOLOGIES INC			
New Permit	**87320**	**HARRIS**	**10/25/2009**
STOLTHAVEN HOUSTON INC			
Permit Renewal	**41618**	**HARRIS**	**10/23/2009**

EXXON MOBIL CORPORATION			
Permit Renewal	**4600**	**HARRIS**	**10/20/2009**
FORMOSA PLASTICS CORPORATION TEXAS			
Permit Renewal	**40157**	**CALHOUN**	**10/20/2009**
JONES BROS DIRT & PAVING CONTRACTORS INC			
New Permit	**89118L001**	**PECOS**	**10/20/2009**
PHILIP RECLAMATION SERVICES HOUSTON LLC			
Permit Renewal	**33961**	**HARRIS**	**10/19/2009**
AKZO NOBEL POLYMER CHEMICALS LLC			
Flexible Permit Renewal	**21865**	**HARRIS**	**10/16/2009**
AKZO NOBEL POLYMER CHEMICALS LLC			
Code = INITPMTCHG CONSTRUCT	**21865**	**HARRIS**	**10/16/2009**
GULF SOUTH PIPELINE COMPANY LP			
Permit Amendment	**76079**	**PANOLA**	**10/16/2009**
SAMSUNG AUSTIN SEMICONDUCTOR LLC			
Permit Amendment	**31811**	**TRAVIS**	**10/15/2009**
ERGON ASPHALT & EMULSIONS INC			
Permit Amendment	**20807**	**ELLIS**	**10/15/2009**
VALLEY BUILDERS SUPPLY MFG COMPANY INC			
Permit Renewal	**9060**	**CAMERON**	**10/13/2009**
TARZAN COOPERATIVE GIN			
Permit Renewal	**41036**	**MARTIN**	**10/13/2009**
OWENS CORNING COMPOSITE MATERIALS LLC			
Permit Amendment	**5042**	**RANDALL**	**10/12/2009**
OWENS CORNING COMPOSITE MATERIALS LLC			
PSD Permit Amendment	**PSDTX844M2**	**RANDALL**	**10/12/2009**
STANDARD AERO SAN ANTONIO INC			

Permit Amendment	**30933A**	**BEXAR**	**10/12/2009**
STANDARD AERO SAN ANTONIO INC			
Permit Renewal	**30933A**	**BEXAR**	**10/12/2009**
TOTAL PETROCHEMICALS USA INC			
Permit Amendment	**54026**	**JEFFERSON**	**10/06/2009**
EQUISTAR CHEMICALS LP			
Permit Renewal	**6257E**	**HARRIS**	**10/06/2009**
RHODIA INC			
Permit Amendment	**56534**	**HARRIS**	**10/05/2009**
OILTANKING HOUSTON LP			
New Permit	**87492**	**HARRIS**	**10/05/2009**
LEIMER BROTHERS INC			
Permit Renewal	**40765A**	**GALVESTON**	**10/05/2009**
LEIMER BROTHERS INC			
Permit Amendment	**40765A**	**GALVESTON**	**10/05/2009**
GIM CHANNELVIEW COGENERATION LLC			
Permit Renewal	**41775**	**HARRIS**	**10/05/2009**
CITY OF GARLAND POWER & LIGHT			
Permit Renewal	**40803**	**COLLIN**	**10/05/2009**
INGRAM CONCRETE LLC			
Permit Renewal	**40672**	**LUBBOCK**	**10/01/2009**
HOLLY ENERGY PARTNERS-OPERATING LP			
Permit Amendment	**17977**	**EL PASO**	**09/30/2009**
SWIFT BEEF COMPANY			
Permit Renewal	**3635A**	**MOORE**	**09/29/2009**
BRENNTAG SOUTHWEST INC			
Permit Renewal	**3939**	**HARRIS**	**09/29/2009**
ASSOCIATED TERMINALS OF GALVESTON LLC			

Permit Amendment	**50498**	**GALVESTON**	**09/29/2009**
BRENNTAG SOUTHWEST INC			
Permit Amendment	**3939**	**HARRIS**	**09/28/2009**
SOUTHERN STAR CONCRETE INC			
Permit Renewal	**4165B**	**DALLAS**	**09/28/2009**
STREET COMMUNITY GIN LTD			
Permit Renewal	**41675**	**SWISHER**	**09/28/2009**
H & L WHOLESALE FEED AND GRAIN INC			
Special Permit Renewal	**17687**	**HOPKINS**	**09/28/2009**
SOUTHERN CRUSHED CONCRETE LLC			
Permit Renewal	**9733C**	**HARRIS**	**09/28/2009**
LINDSEY CONTRACTORS INC			
Permit Renewal	**42292**	**MCLENNAN**	**09/28/2009**
MARTIFER-HIRSCHFELD ENERGY SYSTEMS LLC			
New Permit	**90018**	**TOM GREEN**	**09/25/2009**
PABTEX I LP			
Permit Renewal	**5459A**	**JEFFERSON**	**09/24/2009**
GLENDALE BOAT WORKS INC			
New Permit	**86097**	**HARRIS**	**09/23/2009**
JELD-WEN INC			
Permit Amendment	**21189**	**HOPKINS**	**09/23/2009**
CEMEX CONSTRUCTION MATERIALS SOUTH LLC			
New Permit	**88221**	**EL PASO**	**09/23/2009**
CHANNEL SHIPYARD COMPANY INC			
Permit Amendment	**56318**	**HARRIS**	**09/22/2009**
EI DU PONT DE NEMOURS AND COMPANY			
Permit Renewal	**9176**	**ORANGE**	**09/22/2009**
EXFLUOR RESEARCH CORPORATION			

New Permit	**84719**	**WILLIAMSON**	**09/22/2009**
PHELPS DODGE REFINING CORPORATION			
Permit Renewal	**36726**	**EL PASO**	**09/22/2009**
ENNIS POWER COMPANY LLC			
Permit Renewal	**40363**	**ELLIS**	**09/22/2009**
GULF COAST WASTE DISPOSAL AUTHORITY			
Permit Amendment	**40782**	**HARRIS**	**09/15/2009**
GULF COAST WASTE DISPOSAL AUTHORITY			
Permit Renewal	**40782**	**HARRIS**	**09/15/2009**
TEXSAND DISTRIBUTORS LP			
New Permit	**86250**	**TARRANT**	**09/15/2009**
TEXSAND DISTRIBUTORS LP			
New Permit	**86576**	**TARRANT**	**09/15/2009**
SOUTH TEXAS AGGREGATES INC			
Permit Renewal	**39691**	**MAVERICK**	**09/14/2009**
CITGO PETROLEUM CORPORATION			
Permit Amendment	**18569**	**VICTORIA**	**09/14/2009**
PAWS IN PARADISE PET CREMATORY LLC			
New Standard Permit for Concrete Batch Plant	**89653**	**BELL**	**09/14/2009**
CITGO PETROLEUM CORPORATION			
Code = INITPMTCHG CONSTRUCT	**56151**	**BEXAR**	**09/09/2009**
PYCO INDUSTRIES INC			
Permit Renewal	**8955**	**LUBBOCK**	**09/09/2009**
WTL SAND AND GRAVEL LLC			
Permit Amendment	**85536**	**GRAY**	**09/09/2009**
FRONTERA GENERATION LIMITED PARTNERSHIP			
Permit Renewal	**37613**	**HIDALGO**	**09/08/2009**

CHROMALLOY GAS TURBINE LLC			
Permit Amendment	**24681**	**DALLAS**	**09/08/2009**
CEMEX CONSTRUCTION MATERIALS SOUTH LLC			
New Permit	**87207**	**HARRIS**	**09/08/2009**
MOTIVA ENTERPRISES LLC			
Permit Amendment	**26130**	**ROBERTSON**	**09/08/2009**
ISP TECHNOLOGIES INC			
Permit Amendment	**55847**	**GALVESTON**	**09/08/2009**
EL DORADO CHEMICAL COMPANY			
Permit Renewal	**4425A**	**NAVARRO**	**09/08/2009**
ROBBINS & MYERS ENERGY SYSTEMS LP			
Permit Amendment	**35266**	**MONTGOMERY**	**09/08/2009**
CEMEX CONSTRUCTION MATERIALS SOUTH LLC			
Permit Renewal	**1965A**	**WALLER**	**09/08/2009**
TEXAS DOCKS & RAIL COMPANY LTD			
Permit Renewal	**35323**	**NUECES**	**09/04/2009**
BELL HELICOPTER TEXTRON INC			
Permit Amendment	**18514**	**TARRANT**	**09/04/2009**
ENGINEERED POLYMER SOLUTIONS INC			
Permit Amendment	**18948**	**TARRANT**	**09/01/2009**
FALCON STEEL COMPANY			
New Permit	**84552**	**KAUFMAN**	**09/01/2009**
DURAMAR VENUS INC			
Special Permit Renewal	**17337**	**DALLAS**	**09/01/2009**
COATING APPLICATORS CORPORATION			
Permit Renewal	**38803**	**HARRIS**	**08/31/2009**
POTTER READY MIX LLC			
Permit Renewal	**40323**	**DALLAS**	**08/31/2009**

HOWELL SAND COMPANY INC			
New Permit	**88524L001**	**POTTER**	**08/31/2009**
INTERSTATE TRAILERS INC			
Permit Renewal	**42328**	**TARRANT**	**08/31/2009**
MARTIN OPERATING PARTNERSHIP LP			
Permit Amendment	**76571**	**HALE**	**08/28/2009**
LUMINANT MINING COMPANY LLC			
Permit Amendment	**7084**	**LEE**	**08/24/2009**
BLUDWORTH MARINE LLC			
New Permit	**86595**	**GALVESTON**	**08/24/2009**
PETERSBURG COOPERATIVE GIN			
Permit Renewal	**41372**	**HALE**	**08/24/2009**
JOBE MATERIALS LP			
New Permit	**87653**	**EL PASO**	**08/24/2009**
ALAN RITCHEY INC			
Permit Renewal	**3564**	**COOKE**	**08/24/2009**
KIRBY INLAND MARINE LP			
New Permit	**82407**	**HARRIS**	**08/21/2009**
TARGA MIDSTREAM SERVICES LIMITED PARTNERSHIP			
Permit Amendment	**5414**	**HARRIS**	**08/20/2009**
VALERO REFINING-TEXAS LP			
Flexible Permit Amendment	**39142**	**GALVESTON**	**08/18/2009**
MADISON BELL PARTNERS LP			
New PSD Permit	**PSDTX1105**	**MADISON**	**08/18/2009**
MADISON BELL PARTNERS LP			
New Permit	**83378**	**MADISON**	**08/18/2009**
FIRESTONE POLYMERS LLC			
Flexible Permit Renewal	**292**	**ORANGE**	**08/18/2009**

TRIMAC TRANSPORTATION SOUTH INC			
Permit Renewal	**40710**	**HARRIS**	**08/18/2009**
XIT CONCRETE INC			
Permit Renewal	**18654A**	**HARTLEY**	**08/18/2009**
HEREFORD FARMERS GIN ASSOCIATION INC			
Permit Renewal	**41465**	**DEAF SMITH**	**08/18/2009**
AMERICAN WOOD FIBERS INC			
New Permit	**88311**	**HARRISON**	**08/18/2009**
HOUSTON REFINING LP			
Flexible Permit Amendment	**2167**	**HARRIS**	**08/17/2009**
FLOMIN INC			
Permit Renewal	**37910**	**CHAMBERS**	**08/17/2009**
OXEA CORPORATION			
Permit Amendment	**6105**	**MATAGORDA**	**08/17/2009**
THE INTERNATIONAL GROUP INC			
Permit Renewal	**8566A**	**CHAMBERS**	**08/17/2009**
GULFSTREAM TERMINALS AND MARKETING LLC			
Permit Amendment	**1427B**	**MATAGORDA**	**08/17/2009**
THE DOW CHEMICAL COMPANY			
Permit Amendment	**8567**	**BRAZORIA**	**08/17/2009**
BAYLOR UNIVERSITY			
Permit Renewal	**40418**	**MCLENNAN**	**08/17/2009**
BLACKLAND PRAIRIE GIN INC			
Permit Renewal	**41011**	**LAMAR**	**08/17/2009**
GENTEX POWER CORPORATION			
Permit Renewal	**41437**	**BASTROP**	**08/17/2009**
COMPUTER ENVIRONMENTS INC			

Permit Renewal	**40262**	**DALLAS**	**08/17/2009**
EASTMAN COGENERATION LP			
Permit Renewal	**39842**	**HARRISON**	**08/17/2009**
BRUMLEY MANUFACTURING LLC			
New Permit	**87761**	**WALLER**	**08/11/2009**
COASTAL PLAINS COTTON COMPANY			
Permit Renewal	**41612**	**SAN PATRICIO**	**08/10/2009**
LIBERTY COOPERATIVE GIN			
Permit Renewal	**42071**	**LUBBOCK**	**08/10/2009**
W & W STEEL LLC			
Permit Renewal	**35103**	**LUBBOCK**	**08/07/2009**
BLUDWORTH MARINE LLC			
New Permit	**86174**	**ORANGE**	**08/07/2009**
W & W STEEL LLC			
Permit Amendment	**35103**	**LUBBOCK**	**08/07/2009**
BIGLER LAND LLC			
Permit Amendment	**7278**	**HARRIS**	**08/06/2009**
RIO NOGALES POWER PROJECT LP			
Permit Renewal	**40867**	**GUADALUPE**	**08/06/2009**
VAL-TEX ASPHALT & ENVIRONMENTAL RECYCLING INC			
Change of Location	**89150L001**	**CAMERON**	**08/05/2009**
LOPEZ MARC			
Permit Amendment	**75790**	**STARR**	**08/04/2009**
HELENA CHEMICAL COMPANY			
New Permit	**87626**	**HALE**	**08/03/2009**
UNION CARBIDE CORPORATION			
Permit Renewal	**38481**	**CALHOUN**	**08/03/2009**
K-T GALVANIZING CO INC			

Permit Renewal	**39567**	**JOHNSON**	**07/30/2009**
KALYN/SIEBERT LP			
Permit Renewal	**29229**	**CORYELL**	**07/27/2009**
FLINT HILLS RESOURCES LP			
Flexible Permit Amendment	**6308**	**NUECES**	**07/27/2009**
THE DOW CHEMICAL COMPANY			
Permit Renewal	**37884**	**BRAZORIA**	**07/27/2009**
FLINT HILLS RESOURCES LP			
Flexible Permit Renewal	**19082**	**BEXAR**	**07/27/2009**
HUNTSMAN PETROCHEMICAL CORPORATION			
Permit Renewal	**5952A**	**JEFFERSON**	**07/27/2009**
APAC-TEXAS INC			
Permit Renewal	**6224G**	**JASPER**	**07/27/2009**
ACME BRICK COMPANY			
Change of Location	**86984L001**	**TAYLOR**	**07/27/2009**
HUNTSMAN PETROCHEMICAL CORPORATION			
Permit Amendment	**5952A**	**JEFFERSON**	**07/27/2009**
THOMPSON, BOBBY			
Change of Location	**76663L004**	**DEAF SMITH**	**07/27/2009**
KALYN/SIEBERT LP			
Permit Amendment	**29229**	**CORYELL**	**07/27/2009**
TRANSIT MIX CONCRETE & MATERIALS COMPANY			
Change of Location	**81350L005**	**HARDIN**	**07/27/2009**
GIPSON CONSTRUCTION			
New Permit	**87305L001**	**GILLESPIE**	**07/24/2009**
M & R COTTON PARTNERSHIP LTD			
Permit Renewal	**40118**	**MITCHELL**	**07/23/2009**
TOTAL PETROCHEMICALS USA INC			

Permit Amendment	**46396**	**JEFFERSON**	**07/22/2009**
TOTAL PETROCHEMICALS USA INC			
PSD Permit Amendment	**PSDTX1073M1**	**JEFFERSON**	**07/22/2009**
NACOGDOCHES POWER LLC			
Flexible Permit Amendment	**77679**	**NACOGDOCHES**	**07/21/2009**
ALAMO CONCRETE PRODUCTS LTD			
Permit Renewal	**38600**	**BEXAR**	**07/21/2009**
NACOGDOCHES POWER LLC			
New HAP Permit	**HAP55**	**NACOGDOCHES**	**07/21/2009**
PENRECO			
Permit Renewal	**36481**	**GALVESTON**	**07/20/2009**
FLINT HILLS RESOURCES LP			
Flexible Permit Amendment	**18105**	**HARRISON**	**07/20/2009**
HPC MECHANICAL & COATINGS LLC			
New Permit	**87382**	**SMITH**	**07/20/2009**
PLEASANT HILL COOP GIN			
Permit Renewal	**41739**	**CROSBY**	**07/20/2009**
ATRIUM COMPANIES INC			
Permit Renewal	**42072**	**COLLIN**	**07/20/2009**
FLINT HILLS RESOURCES LP			
Flexible Permit Amendment	**8803A**	**NUECES**	**07/16/2009**
MOTIVA ENTERPRISES LLC			
Flexible Permit Amendment	**8404**	**JEFFERSON**	**07/13/2009**
FORMOSA PLASTICS CORPORATION TEXAS			
Permit Amendment	**19166**	**CALHOUN**	**07/13/2009**
NUSTAR LOGISTICS LP			
Flexible Permit Renewal	**54984**	**NUECES**	**07/13/2009**

FROST CRUSHED STONE COMPANY INC			
New Permit	**86518L001**	**LIMESTONE**	**07/13/2009**
RHODIA INC			
Permit Amendment	**9565**	**HARRIS**	**07/13/2009**
RHODIA INC			
PSD Permit Amendment	**PSDTX695M2**	**HARRIS**	**07/13/2009**
FOAM FABRICATORS INC			
Permit Renewal	**35668**	**TARRANT**	**07/13/2009**
NUCOR CORPORATION			
Permit Renewal	**41135**	**KAUFMAN**	**07/13/2009**
ONEOK WESTEX TRANSMISSION LLC			
Permit Renewal	**9005**	**WHEELER**	**07/13/2009**
BLUE STAR MATERIALS LLC			
New Permit	**88090**	**WISE**	**07/09/2009**
AKZO NOBEL POLYMER CHEMICALS LLC			
Permit Renewal	**7700**	**HARRIS**	**07/07/2009**
UNION CARBIDE CORPORATION			
Permit Renewal	**49004**	**GALVESTON**	**07/07/2009**
UNION CARBIDE CORPORATION			
Permit Renewal	**18369**	**GALVESTON**	**07/07/2009**
MASTERCRAFT WOOD PRODUCTS LP			
Permit Amendment	**79661**	**HARRISON**	**07/06/2009**
NUCOR CORPORATION			
Permit Renewal	**2430**	**LEON**	**07/06/2009**
DEAN WORD COMPANY LTD			
Permit Renewal	**702A**	**COMAL**	**07/06/2009**
INNOVENE USA LLC			
Permit Renewal	**9517**	**BRAZORIA**	**06/30/2009**

INEOS USA LLC			
Flexible Permit Amendment	**95**	**BRAZORIA**	**06/30/2009**
INEOS USA LLC			
PSD Permit Amendment	**PSDTX854M2**	**BRAZORIA**	**06/30/2009**
CLEARWATER INTERNATIONAL LLC			
New Permit	**81694**	**BEXAR**	**06/30/2009**
ENBRIDGE G & P NORTH TEXAS LP			
Permit Renewal	**8935**	**ERATH**	**06/29/2009**
THE PREMCOR REFINING GROUP INC			
New Permit	**86757**	**JEFFERSON**	**06/29/2009**
APAC-TEXAS INC			
Permit Renewal	**5960A**	**DALLAS**	**06/29/2009**
BAILLIET JOHN V			
Permit Renewal	**38654**	**HARRIS**	**06/29/2009**
BROWN TRANSPORT INC			
Permit Renewal	**40399**	**HUTCHINSON**	**06/29/2009**
BASELL USA INC			
Permit Amendment	**19546**	**HARRIS**	**06/23/2009**
CHAMPION TECHNOLOGIES INC			
New Permit	**86563**	**WISE**	**06/23/2009**
ERNA FRAC SAND LC			
New Permit	**86577**	**MASON**	**06/23/2009**
LAMAR POWER PARTNERS II LLC			
New Permit	**83207**	**LAMAR**	**06/22/2009**
LAMAR POWER PARTNERS II LLC			
New PSD Permit	**PSDTX1106**	**LAMAR**	**06/22/2009**
TOTAL PETROCHEMICALS USA INC			
Permit Renewal	**8983A**	**JEFFERSON**	**06/22/2009**

LETOURNEAU TECHNOLOGIES DRILLING SYSTEMS INC			
Permit Amendment	**77623**	**HARRIS**	**06/22/2009**
EQUISTAR CHEMICALS LP			
Permit Renewal	**6257F**	**HARRIS**	**06/22/2009**
MOTIVA ENTERPRISES LLC			
Flexible Permit Amendment	**19035**	**BEXAR**	**06/22/2009**
CITY CONCRETE INC			
Change of Location	**53449L005**	**WICHITA**	**06/22/2009**
PATTILLO BRANCH POWER COMPANY LLC			
New Permit	**83642**	**FANNIN**	**06/17/2009**
PATTILLO BRANCH POWER COMPANY LLC			
New PSD Permit	**PSDTX1115**	**FANNIN**	**06/17/2009**
KNIFE RIVER CORPORATION SOUTH			
Permit Renewal	**39213**	**BURNET**	**06/16/2009**
INGRAM READYMIX INC			
Change of Location	**54819L004**	**LA SALLE**	**06/16/2009**
HARGILL GROWERS GIN INC			
Permit Renewal	**41035**	**HIDALGO**	**06/16/2009**
FLINT HILLS RESOURCES LP			
Flexible Permit Renewal	**6308**	**NUECES**	**06/15/2009**
21C FOODS LLP			
Permit Renewal	**40155**	**POTTER**	**06/15/2009**
EXXONMOBIL OIL CORPORATION			
Code = INITPMTCHG FLEXIBLE G	**49131**	**JEFFERSON**	**06/15/2009**
COWTOWN EXCAVATING COMPANY			
Permit Renewal	**40019**	**TARRANT**	**06/15/2009**
VULCAN CONSTRUCTION MATERIALS LP			

Permit Renewal	**40670**	**BROWN**	**06/15/2009**
OCCIDENTAL CHEMICAL CORPORATION			
Permit Renewal	**7565B**	**DALLAS**	**06/15/2009**
MAGELLAN TERMINALS HOLDINGS LP			
Flexible Permit Amendment	**4850**	**HARRIS**	**06/12/2009**
CHS INC			
New Permit	**87678**	**PARMER**	**06/12/2009**
ARROWHEAD PIPELINE LP			
Permit Renewal	**79228**	**BRAZORIA**	**06/10/2009**
OIL STATES INDUSTRIES INC			
Permit Renewal	**37574**	**HARRIS**	**06/09/2009**
OIL STATES INDUSTRIES INC			
Permit Amendment	**37574**	**HARRIS**	**06/09/2009**
BASF CORPORATION			
Permit Renewal	**7595A**	**BRAZORIA**	**06/09/2009**
BASF CORPORATION			
Permit Amendment	**7595A**	**BRAZORIA**	**06/09/2009**
WTL SAND AND GRAVEL LLC			
New Permit	**87182**	**ROBERTS**	**06/09/2009**
LIPHAM CONSTRUCTION CO INC			
Change of Location	**78420L002**	**DEAF SMITH**	**06/09/2009**
TOTAL PETROCHEMICALS USA INC			
Permit Renewal	**9194A**	**JEFFERSON**	**06/08/2009**
TOTAL PETROCHEMICALS USA INC			
Permit Renewal	**9195A**	**JEFFERSON**	**06/08/2009**
SUNRAY CO-OP			
Permit Renewal	**70147**	**DALLAM**	**06/08/2009**
E R CARPENTER LP			

Permit Amendment	**20625**	**BELL**	**06/08/2009**
HARRIS, DOUGLAS WAYNE			
New Standard Permit for Concrete Batch Plant	**87614**	**HAMILTON**	**06/08/2009**
SUNOCO PARTNERS MARKETING & TERMINALS LP			
Permit Renewal	**40120**	**HARRISON**	**06/08/2009**
WORLDWIDE ALLOY SURFACING II LLC			
New Permit	**85304**	**HARRIS**	**06/04/2009**
GREENS BAYOU PIPE MILL LP			
New Permit	**85893**	**HARRIS**	**06/04/2009**
ALLEN BUTLER CONSTRUCTION INC			
New Permit	**86874**	**MOTLEY**	**06/02/2009**
TEXAS METAL CASTING CO			
Permit Amendment	**76522**	**ANGELINA**	**06/01/2009**
G & S ASPHALT INC			
Permit Renewal	**39841**	**FORT BEND**	**06/01/2009**
CLOSE CITY COOPERATIVE GIN			
Permit Renewal	**41604**	**GARZA**	**06/01/2009**
OK CONCRETE COMPANY			
New Permit	**87643**	**WILBARGER**	**06/01/2009**
RAYTHEON COMPANY			
New Permit	**84943**	**DALLAS**	**05/29/2009**
BASF CORPORATION			
Permit Amendment	**8074A**	**BRAZORIA**	**05/28/2009**
BASF CORPORATION			
Permit Renewal	**8074A**	**BRAZORIA**	**05/28/2009**
EAST TEXAS ASPHALT CO LTD			
Permit Amendment	**23279**	**ANGELINA**	**05/27/2009**

EXPLORER PIPELINE COMPANY			
Permit Renewal	**36100**	**JEFFERSON**	**05/26/2009**
LYONDELL CHEMICAL COMPANY			
Permit Amendment	**9395**	**HARRIS**	**05/26/2009**
US SILICA COMPANY			
New Permit	**77337**	**LIMESTONE**	**05/26/2009**
BLUE LINE CORPORATION			
New Permit	**84176**	**BEXAR**	**05/26/2009**
INTERGULF CORPORATION			
New Permit	**85092**	**HARRIS**	**05/26/2009**
KONECRANES AMERICA INC			
New Permit	**85145**	**HARRIS**	**05/26/2009**
SOUTHERN CLAY PRODUCTS INC			
Permit Amendment	**5168**	**GONZALES**	**05/26/2009**
EQUISTAR CHEMICALS LP			
Permit Renewal	**8125**	**HARRIS**	**05/26/2009**
CLW INC			
New Permit	**87202**	**SAN JACINTO**	**05/26/2009**
B & G MATERIALS LLC			
New Permit	**87155L001**	**BEE**	**05/26/2009**
SMITH FARMERS GIN INC			
Permit Renewal	**41566**	**FORT BEND**	**05/26/2009**
DALLUGE, JEFF			
New Permit	**87461L001**	**SWISHER**	**05/26/2009**
US DEPARTMENT OF THE ARMY			
Permit Renewal	**39616**	**BOWIE**	**05/26/2009**
US DEPARTMENT OF THE ARMY			
Permit Amendment	**39616**	**BOWIE**	**05/26/2009**

US DEPARTMENT OF THE ARMY			
Flexible Permit Amendment	**79097**	**EL PASO**	**05/22/2009**
EASTMAN CHEMICAL COMPANY			
Permit Renewal	**9167**	**HARRISON**	**05/20/2009**
FORMOSA PLASTICS CORPORATION TEXAS			
Permit Amendment	**19871**	**CALHOUN**	**05/20/2009**
PAWS MEMORIAL SERVICE LLC			
New Standard Permit for Concrete Batch Plant	**87481**	**FORT BEND**	**05/20/2009**
ENTERGY TEXAS INC			
New Permit	**83784**	**MONTGOMERY**	**05/19/2009**
ENTERGY TEXAS INC			
New PSD Permit	**PSDTX1116**	**MONTGOMERY**	**05/19/2009**
ENTERGY TEXAS INC			
New NA Permit	**N73**	**MONTGOMERY**	**05/19/2009**
FEDERAL HEATH SIGN COMPANY LLC			
New Permit	**78766**	**CHEROKEE**	**05/19/2009**
SUNRAY CO-OP			
Permit Renewal	**44000**	**DALLAM**	**05/19/2009**
STATE SERVICE CO INC			
Permit Renewal	**33959**	**SAN PATRICIO**	**05/18/2009**
INEOS AMERICAS LLC			
New Permit	**83831**	**JEFFERSON**	**05/18/2009**
STATE SERVICE CO INC			
Permit Amendment	**33959**	**SAN PATRICIO**	**05/18/2009**
WASTE CONTROL SPECIALISTS LLC			
Permit Amendment	**72653**	**ANDREWS**	**05/18/2009**
GEUS			

New Permit	**86301**	**HUNT**	**05/18/2009**
GEUS			
New PSD Permit	**PSDTX1173**	**HUNT**	**05/18/2009**
BEASLEY FARMERS GIN COMPANY			
Permit Renewal	**41466**	**FORT BEND**	**05/18/2009**
SHINTECH INCORPORATED			
New Permit	**82045**	**BRAZORIA**	**05/15/2009**
SHINTECH INCORPORATED			
New PSD Permit	**PSDTX1094**	**BRAZORIA**	**05/15/2009**
SHINTECH INCORPORATED			
New NA Permit	**N68**	**BRAZORIA**	**05/15/2009**
SHINTECH INCORPORATED			
New HAP Permit	**HAP9**	**BRAZORIA**	**05/15/2009**
WESTLAKE LONGVIEW CORPORATION			
Permit Amendment	**19959**	**HARRISON**	**05/11/2009**
TEXAS LIME COMPANY			
Permit Renewal	**7501**	**JOHNSON**	**05/11/2009**
SALTYS MANUFACTURING LTD			
New Permit	**83389**	**SHELBY**	**05/11/2009**
ROCK CRUSHERS INC			
Change of Location	**52388L003**	**WASHINGTON**	**05/11/2009**
MERKEL ELEVATOR AND FARM SUPPLY INC			
New Permit	**87176**	**TAYLOR**	**05/11/2009**
SUPERIOR WELL SERVICES LTD			
New Permit	**87235**	**MIDLAND**	**05/11/2009**
KING-MESA INC			
Permit Renewal	**41773**	**DAWSON**	**05/11/2009**
CAVINESS BEEF PACKERS LTD			

New Permit	**81570**	**DEAF SMITH**	**05/08/2009**
ELEMENTIS CHROMIUM LP			
Permit Renewal	**7736**	**NUECES**	**05/08/2009**
ELEMENTIS CHROMIUM LP			
Permit Amendment	**7736**	**NUECES**	**05/08/2009**
US DEPARTMENT OF ENERGY			
New Flexible Permit	**84802**	**CARSON**	**05/05/2009**
TRANSMONTAIGNE OPERATING COMPANY LP			
Permit Amendment	**7195A**	**CAMERON**	**05/05/2009**
ROHM AND HAAS TEXAS INCORPORATED			
Permit Amendment	**723**	**HARRIS**	**05/05/2009**
INEOS AMERICAS LLC			
Permit Renewal	**5215A**	**JEFFERSON**	**05/05/2009**
CONOCOPHILLIPS COMPANY			
Permit Renewal	**9008**	**TARRANT**	**05/04/2009**
MILE 533 MARINE WAYS INC			
New Permit	**85037**	**SAN PATRICIO**	**05/04/2009**
FORT WORTH CRUSHED STONE LC			
New Permit	**86966L001**	**HOOD**	**05/04/2009**
CHEVRON PHILLIPS CHEMICAL COMPANY LP			
Flexible Permit Renewal	**583A**	**ORANGE**	**05/04/2009**
AGUA DULCE GRAIN CO INC			
Permit Renewal	**4215**	**JIM WELLS**	**04/28/2009**
CAMPBELL, RYAN W			
New Standard Permit for Concrete Batch Plant	**86752**	**HARRIS**	**04/28/2009**
LETOURNEAU TECHNOLOGIES INC			
Permit Amendment	**186**	**GREGG**	**04/27/2009**

LETOURNEAU INC			
New PSD Permit	**PSDTX1102**	**GREGG**	**04/27/2009**
E R CARPENTER LP			
Permit Amendment	**20625**	**BELL**	**04/27/2009**
REGENCY FIELD SERVICES LLC			
Permit Amendment	**9357**	**WARD**	**04/27/2009**
REGENCY FIELD SERVICES LLC			
Permit Renewal	**9357**	**WARD**	**04/27/2009**
E R CARPENTER LP			
Permit Amendment	**4757**	**HARRIS**	**04/27/2009**
CEMEX CONSTRUCTION MATERIALS SOUTH LLC			
Permit Renewal	**639C**	**BRAZORIA**	**04/27/2009**
AMERROCK PRODUCTS LP			
Permit Renewal	**9397**	**BELL**	**04/27/2009**
EI DU PONT DE NEMOURS AND COMPANY			
Permit Amendment	**9629**	**ORANGE**	**04/22/2009**
ROWAN COMPANIES INC			
Permit Amendment	**27937**	**JEFFERSON**	**04/20/2009**
SEADRIFT COKE LP			
Permit Amendment	**70898**	**CALHOUN**	**04/20/2009**
TEXAS ARMY NATIONAL GUARD			
Permit Amendment	**55711**	**TARRANT**	**04/20/2009**
MAJEK BOATWORKS INC			
New Permit	**85144**	**NUECES**	**04/20/2009**
OWENS CORNING ROOFING AND ASPHALT LLC			
Permit Amendment	**81011**	**DALLAS**	**04/20/2009**
THE GOODYEAR TIRE & RUBBER COMPANY			
Permit Renewal	**38755**	**JEFFERSON**	**04/20/2009**

QUALITY SAND INC			
New Permit	**86713L001**	**HUNT**	**04/20/2009**
AMERICAN INDUSTRIAL MINERALS LLC			
New Permit	**87201**	**ORANGE**	**04/20/2009**
TEXAS REFINERY CORP			
Permit Renewal	**3800**	**TARRANT**	**04/20/2009**
ELLWOOD TEXAS FORGE LP			
Permit Renewal	**40256**	**HARRIS**	**04/17/2009**
CAPACITY OF TEXAS INC			
Permit Amendment	**28439**	**GREGG**	**04/13/2009**
OXBOW CALCINING LLC			
Permit Amendment	**5421**	**JEFFERSON**	**04/13/2009**
BIG CITY CRUSHED CONCRETE LP			
Permit Amendment	**21393**	**DALLAS**	**04/13/2009**
SUNRAY CO-OP			
Permit Renewal	**70320**	**HANSFORD**	**04/13/2009**
MARTIN PRODUCT SALES LLC			
New Permit	**86979**	**JEFFERSON**	**04/13/2009**
BLUEBONNET PET CREMATORY LLC			
Permit Renewal	**40398**	**BEXAR**	**04/13/2009**
SUPERIOR FIBERGLASS INC			
Permit Renewal	**40941**	**CHEROKEE**	**04/13/2009**
MOSES GIN I NC			
Permit Renewal	**41540**	**WHARTON**	**04/13/2009**
FLOWER GROVE COOPERATIVE GIN			
Permit Renewal	**41165**	**MARTIN**	**04/13/2009**
LONE STAR INDUSTRIES INC			
New Permit	**82775**	**NOLAN**	**04/10/2009**

LONE STAR INDUSTRIES INC			
New PSD Permit	**PSDTX1101**	**NOLAN**	**04/10/2009**
PRATT & WHITNEY SERVICES INC			
Permit Amendment	**20842**	**TARRANT**	**04/10/2009**
REYNOLDS INTERNATIONAL LP			
New Permit	**75911**	**HIDALGO**	**04/07/2009**
SHATLEY, JACK			
Special Permit Renewal	**17464**	**TARRANT**	**04/06/2009**
MILPRINT INC			
Permit Renewal	**16958**	**GREGG**	**04/06/2009**
ENBRIDGE G & P NORTH TEXAS LP			
Permit Amendment	**6630A**	**EASTLAND**	**04/06/2009**
HAYS ENERGY LIMITED PARTNERSHIP			
Permit Renewal	**40040**	**HAYS**	**04/06/2009**
BLOCK CREEK CONCRETE PRODUCTS LLC			
New Standard Permit for Concrete Batch Plant	**83958**	**KENDALL**	**04/01/2009**
TENASKA GATEWAY PARTNERS LTD			
Permit Renewal	**40039**	**RUSK**	**04/01/2009**
FLINT HILLS RESOURCES LP			
Flexible Permit Renewal	**19079**	**TRAVIS**	**03/31/2009**
ALON USA LP			
Permit Amendment	**53425**	**HOWARD**	**03/31/2009**
REGENCY FIELD SERVICES LLC			
Permit Amendment	**6051**	**HENDERSON**	**03/30/2009**
TEXAS INSTRUMENTS INCORPORATED			
Permit Amendment	**9459**	**FORT BEND**	**03/30/2009**
THE PREMCOR REFINING GROUP INC			

Flexible Permit Renewal	**6825A**	**JEFFERSON**	**03/30/2009**
SOLUTIA INC			
Permit Renewal	**39171**	**BRAZORIA**	**03/30/2009**
NEW NGC INC			
Permit Renewal	**39683**	**TARRANT**	**03/30/2009**
SAN MIGUEL ELECTRIC COOPERATIVE INC			
Permit Renewal	**4180A**	**ATASCOSA**	**03/30/2009**
UNION CARBIDE CORPORATION			
Permit Amendment	**47091**	**CALHOUN**	**03/30/2009**
CONAGRA FOODS INC			
Permit Renewal	**40089**	**TARRANT**	**03/27/2009**
DELTA PETROLEUM COMPANY INC			
Permit Renewal	**38746**	**HARRIS**	**03/25/2009**
BASF CONSTRUCTION CHEMICALS LLC			
Permit Amendment	**78630**	**DALLAS**	**03/23/2009**
TEXAS LIME COMPANY			
Permit Renewal	**5602A**	**JOHNSON**	**03/23/2009**
THOMAS SAND & GRAVEL COMPANY INC			
New Permit	**85856L001**	**POTTER**	**03/23/2009**
JORDAN PLATING INC			
Permit Renewal	**39599**	**BEXAR**	**03/23/2009**
BASF CONSTRUCTION CHEMICALS LLC			
Permit Amendment	**78630**	**DALLAS**	**03/23/2009**
PENCCO INC			
New Permit	**85661**	**AUSTIN**	**03/20/2009**
E I DU PONT DE NEMOURS AND COMPANY			
Permit Amendment	**2446A**	**HARRIS**	**03/18/2009**
TIN INC			

Permit Amendment	**9654A**	**ORANGE**	**03/16/2009**
TIN INC			
PSD Permit Amendment	**PSDTX833M3**	**ORANGE**	**03/16/2009**
TIN INC			
NA Permit Amendment	**N60M2**	**ORANGE**	**03/16/2009**
CSA MATERIALS INC			
Change of Location	**83052L003**	**COLEMAN**	**03/16/2009**
BECK STEEL INC			
Permit Renewal	**39214**	**LUBBOCK**	**03/16/2009**
WILLIAMS GIN & GRAIN INC			
Permit Renewal	**41202**	**NAVARRO**	**03/16/2009**
GULF COAST COOPERATIVE			
Permit Renewal	**40211**	**NUECES**	**03/16/2009**
CSA MATERIALS INC			
Change of Location	**73852L002**	**UPTON**	**03/16/2009**
GULF COAST COOPERATIVE			
New Permit	**87191**	**NUECES**	**03/16/2009**
ARMSTRONG HARDWOOD FLOORING COMPANY			
Permit Amendment	**21144**	**SHELBY**	**03/12/2009**
ALLIED FEEDS INC			
New Permit	**84780**	**BEXAR**	**03/12/2009**
LOUISIANA-PACIFIC CORPORATION			
Permit Amendment	**22377**	**JASPER**	**03/11/2009**
LOUISIANA-PACIFIC CORPORATION			
PSD Permit Amendment	**PSDTX832M5**	**JASPER**	**03/11/2009**
MARTINEZ NOE			
New Permit	**83365**	**BRAZORIA**	**03/10/2009**
MW TEXAS DIE CASTING INC			

Permit Renewal	**39945**	**GREGG**	**03/09/2009**
TIN INC			
Permit Amendment	**1037**	**SABINE**	**03/03/2009**
TIN INC			
PSD Permit Amendment	**PSDTX924M1**	**SABINE**	**03/03/2009**
WELLS CARGO INC			
Permit Renewal	**37339**	**MCLENNAN**	**03/03/2009**
WELLS CARGO INC			
Permit Amendment	**37339**	**MCLENNAN**	**03/03/2009**
SANDEN INTERNATIONAL USA INC			
Permit Renewal	**40519**	**COLLIN**	**03/03/2009**
SUNRAY ETHANOL LLC			
Permit Amendment	**77549**	**MOORE**	**03/03/2009**
TONY LAMA COMPANY			
Permit Renewal	**40036**	**EL PASO**	**03/03/2009**
CATERPILLAR INC			
New Permit	**87118**	**GUADALUPE**	**03/03/2009**
BOSQUE POWER COMPANY LLC			
Permit Amendment	**40620**	**BOSQUE**	**02/27/2009**
BOSQUE POWER COMPANY LLC			
Permit Renewal	**40620**	**BOSQUE**	**02/27/2009**
BOSQUE POWER COMPANY LLC			
PSD Permit Amendment	**PSDTX931M1**	**BOSQUE**	**02/27/2009**
CENTURY ASPHALT LTD			
Change of Location	**83417L002**	**HARRIS**	**02/27/2009**
TETRA PAK MATERIALS LP			
Permit Renewal	**20652**	**DENTON**	**02/26/2009**

TETRA PAK MATERIALS LP			
Permit Amendment	**20652**	**DENTON**	**02/26/2009**
SHELL PIPELINE COMPANY LP			
New Permit	**86605**	**GALVESTON**	**02/24/2009**
EXXON MOBIL CORPORATION			
New Permit	**86719**	**WOOD**	**02/24/2009**
HOSPIRA INC			
Permit Renewal	**40904**	**TRAVIS**	**02/24/2009**
INVISTA SARL			
Permit Renewal	**810**	**VICTORIA**	**02/23/2009**
INVISTA SARL			
Permit Amendment	**810**	**VICTORIA**	**02/23/2009**
JOBE MATERIALS LP			
New Permit	**84441L001**	**EL PASO**	**02/23/2009**
BEE AGRICULTURAL COMPANY			
Permit Renewal	**8179**	**BEE**	**02/23/2009**
ROYAL BATHS MANUFACTURING COMPANY LTD			
Permit Renewal	**42290**	**HARRIS**	**02/23/2009**
WILBUR-ELLIS COMPANY			
New Permit	**86285**	**DEAF SMITH**	**02/19/2009**
GE ENGINE SERVICES-MCALLEN LP			
Permit Amendment	**84073**	**HIDALGO**	**02/17/2009**
PASADENA COGENERATION LP			
Permit Renewal	**37283**	**HARRIS**	**02/16/2009**
TXI OPERATIONS LP			
New Permit	**85868**	**COLORADO**	**02/16/2009**
VALDEZ JR EUGENIO			
New Permit	**86469**	**CAMERON**	**02/16/2009**

LONE STAR READY-MIX LP			
New Standard Permit for Concrete Batch Plant	**86832L001**	**CAMERON**	**02/10/2009**
MARTIN OPERATING PARTNERSHIP LP			
Permit Renewal	**35842**	**JEFFERSON**	**02/09/2009**
MARTIN OPERATING PARTNERSHIP LP			
Permit Amendment	**35842**	**JEFFERSON**	**02/09/2009**
INVISTA SARL			
New Permit	**83695**	**HARRIS**	**02/09/2009**
ALUMAX MILL PRODUCTS INC			
Permit Amendment	**9476**	**BOWIE**	**02/09/2009**
ALUMAX MILL PRODUCTS INC			
PSD Permit Amendment	**PSDTX886M1**	**BOWIE**	**02/09/2009**
NORTH AMERICAN GALVANIZING COMPANY			
Permit Renewal	**38389**	**TARRANT**	**02/09/2009**
BARKENS HARDCHROME INC			
New Permit	**85473**	**JOHNSON**	**02/09/2009**
MALIN INTERNATIONAL SHIP REPAIR & DRYDOCK INC			
New Permit	**85079**	**GALVESTON**	**02/09/2009**
COOPERATIVE GIN ASSN OF LORAINE MITCHELL COUNTY TEXAS			
Permit Renewal	**40639**	**MITCHELL**	**02/09/2009**
MULESHOE COOPERATIVE GIN COMPANY			
Permit Renewal	**40766**	**BAILEY**	**02/09/2009**
ZACH SYSTEM CORPORATION			
Permit Amendment	**83364**	**HARRIS**	**02/09/2009**
VOUGHT AIRCRAFT INDUSTRIES INC			
Permit Renewal	**41403**	**DALLAS**	**02/09/2009**
BARRETTS MINERALS INC			

Permit Renewal	**40503**	**MATAGORDA**	**02/09/2009**
LONGVIEW ASPHALT INC			
Permit Amendment	**38214**	**GREGG**	**02/06/2009**
BASF FINA PETROCHEMICALS LIMITED PARTNERSHIP			
Permit Amendment	**36644**	**JEFFERSON**	**02/05/2009**
DUOLINE TECHNOLOGIES LP			
New Permit	**86968**	**UPSHUR**	**02/05/2009**
CELANESE LTD			
Permit Amendment	**19618**	**HARRIS**	**02/03/2009**
VOUGHT AIRCRAFT INDUSTRIES INC			
Permit Renewal	**40720**	**DALLAS**	**02/03/2009**
NUSTAR LOGISTICS LP			
Permit Renewal	**35764**	**HALE**	**02/02/2009**
ARROW MARBLE LLC			
Permit Amendment	**47669**	**HARRIS**	**02/02/2009**
JOBE MATERIALS LP			
New Permit	**84723**	**EL PASO**	**02/02/2009**
JOBE MATERIALS LP			
New Permit	**84726**	**EL PASO**	**02/02/2009**
STERIS ISOMEDIX SERVICES INC			
Permit Renewal	**38690**	**TARRANT**	**02/02/2009**
WAPITI OPERATING LLC			
New Permit	**85363**	**MONTGOMERY**	**02/02/2009**
SW FOAM LLC			
Permit Renewal	**38876**	**EL PASO**	**02/02/2009**
GREIF PACKAGING LLC			
Permit Renewal	**39946**	**HARRIS**	**02/02/2009**
REPUBLIC PLASTICS LTD			

Permit Renewal	**40212**	**GUADALUPE**	**02/02/2009**
THOMAS REDI-MIX COMPANY INC			
New Permit	**86136L001**	**POTTER**	**01/27/2009**
POWELL INDUSTRIES INC			
Permit Renewal	**40834**	**HARRIS**	**01/27/2009**
CITY OF BRYAN			
Permit Renewal	**4415**	**BRAZOS**	**01/27/2009**
LOADCRAFT INDUSTRIES LTD			
New Permit	**82943**	**MCCULLOCH**	**01/26/2009**
SOLUTIA INC			
Permit Renewal	**38336**	**BRAZORIA**	**01/26/2009**
US PLY INC			
New Permit	**85680**	**TARRANT**	**01/26/2009**
GUADALUPE POWER PARTNERS LP			
Permit Renewal	**38659**	**GUADALUPE**	**01/26/2009**
KINDER MORGAN PRODUCTION COMPANY LLC			
Permit Renewal	**9608**	**PECOS**	**01/26/2009**
GOLDEN SPREAD REDI-MIX INC			
New Standard Permit for Concrete Batch Plant	**81432L007**	**NOLAN**	**01/26/2009**
SOUTH TEXAS ELECTRIC COOPERATIVE INC			
New Permit	**84824**	**FRIO**	**01/23/2009**
SOUTH TEXAS ELECTRIC COOPERATIVE INC			
New PSD Permit	**PSDTX1133**	**FRIO**	**01/23/2009**
SRW COGENERATION LIMITED PARTNERSHIP			
Permit Renewal	**40496**	**ORANGE**	**01/22/2009**
G & P SEED CO INC			
Permit Renewal	**38331**	**HILL**	**01/21/2009**

P&WC AEROSPACE US INC			
Permit Renewal	**38383**	**WICHITA**	**01/20/2009**
P&WC AEROSPACE US INC			
Permit Amendment	**38383**	**WICHITA**	**01/20/2009**
CHEVRON USA INC			
Permit Renewal	**9319**	**STERLING**	**01/20/2009**
COLORADO MATERIALS LTD			
Permit Renewal	**38479**	**VICTORIA**	**01/20/2009**
HESS CORPORATION			
Permit Renewal	**9235**	**GAINES**	**01/20/2009**
WTG GAS PROCESSING LP			
Permit Renewal	**8461**	**HOWARD**	**01/20/2009**
HUNTON ENERGY FREEPORT HOLDINGS LLC			
New Permit	**85209**	**BRAZORIA**	**01/16/2009**
OXY USA WTP LP			
Permit Amendment	**20660**	**KENT**	**01/16/2009**
WACO COMPOSITES I LTD			
New Permit	**80500**	**MCLENNAN**	**01/15/2009**
PENCCO INC			
New Permit	**85567**	**ELLIS**	**01/15/2009**
WTG GAS PROCESSING LP			
Permit Renewal	**36189**	**HOWARD**	**01/12/2009**
VENABLES WELDING & ROUSTABOUT INC			
New Permit	**86290L001**	**OLDHAM**	**01/06/2009**

You can contact us at airperm@tceq.state.tx.us if you have any questions.

List of Texas Utilities (Water or Sewer)

Utility Name: White Shed Search Advanced Search

CCN or Registration #:

Total Active Water Utilities: 3196
Total Active Sewer Utilities: 821

Total Active Submetered Properties: 1191
Total Active Allocated Properties: 4504

CCN's begin with a 1 (for water) or a 2 (for sewer). All others are registration numbers.

Utility Name	CCN or Reg#	Activity Status	District
WHITE SHED WSC	10170	ACTIVE	
WHITE TAIL RIDGE LAKES ESTATES	10483	CCN CANCELLED	
WHITECLIFF UTILITIES INC	11914	CCN CANCELLED	
WHITEMOUND WSC	X0619	INACTIVE	
WHITEOAK SHORES SEWER SERVICE CORPORATION	20827	ACTIVE	
WHITEOAK SHORES WATER SERVICE INC	O0570	INACTIVE	
WHITEOAK SHORES WATER SERVICES	O0909	CCN CANCELLED	
WHITEROCK	S4243	ACTIVE	
WHITEWATER SPRINGS WATER SYSTEM	A1332	PROPOSED	
WHITHARRAL WSC	12505	ACTIVE	
WHITT WSC	12276	ACTIVE	
WHITTFILED APARTMENTS	S3788	ACTIVE	
WICHITA VALLEY WSC	10268	ACTIVE	
WICKSON CREEK SUD	11544	ACTIVE	WICKSON CREEK SUD
WIEDENFELD WATER WORKS	O0530	CCN CANCELLED	
WIEDENFELD WATER WORKS INC	12052	ACTIVE	
WILBARGER CREEK MUD 1	P1378	ACTIVE	WILBARGER CREEK MUD 1
WILCO WATER CO	12366	CCN CANCELLED	
WILDERNESS SOUND	11699	ACTIVE	
WILDEWOOD APTS	S5126	ACTIVE	
WILDEWOOD SUBDIVISION	N0003	ACTIVE	
WILDEWOOD WATER CO INC	11620	CCN CANCELLED	
WILDFLOWER APARTMENT HOMES	S4799	ACTIVE	
WILDFLOWER APARTMENTS	S0648	ACTIVE	
WILDFLOWER APARTMENTS	S4527	ACTIVE	
WILDFLOWER APTS	S4509	INACTIVE	
WILDFLOWER GREEN HOMEOWNERS ASSOCIATION INC	S1815	ACTIVE	
WILDFLOWER VILLAS APTS	S5432	ACTIVE	
WILDORADO WSC	11343	ACTIVE	

WILDWOOD	S2582	ACTIVE
WILDWOOD ACRES WSC	11169	CCN CANCELLED
WILDWOOD APARTMENTS	S4395	ACTIVE
WILDWOOD BRANCH	S4690	ACTIVE
WILDWOOD CIRCLE PROPERTY OWNERS ASSOCIATION INC	11789	ACTIVE
WILDWOOD ESTATES WATER SUPPLY	O0240	CCN CANCELLED
WILDWOOD FOREST APARTMENTS	S0761	ACTIVE
WILDWOOD PROPERTY OWNERS ASSOCIATION	10107	ACTIVE
WILDWOOD PROPERTY OWNERS ASSOCIATION	20044	ACTIVE
WILEY CAMERON P RANCH	A1023	INACTIVE
WILKE LANE UTILITY COMPANY	X0728	INACTIVE
WILKINS CONTRACTING INC	20679	ACTIVE
WILL CLAYTON MANOR APARTMENTS	X0312	INACTIVE
WILLARD STREET APARTMENT	S3762	ACTIVE
WILLIAM SWINNEY & COMPANY	X0190	INACTIVE
WILLIAMS BURG APARTMENT HOMES	S4244	ACTIVE
WILLIAMS COVE	S1655	ACTIVE
WILLIAMS RUN APARTMENTS	S3142	ACTIVE
WILLIAMS TOWN APARTMENTS	S3939	ACTIVE
WILLIAMS WSC	10818	CCN CANCELLED
WILLIAMSBURG CONDOMINIUMS	S1467	ACTIVE

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Texas Coastal Management Program

The Texas Coastal Management Program (CMP) seeks to ensure the long-term environmental and economic health of the Texas coast through management of the state's coastal natural resource areas. The Coastal Coordination Council, a public/private council chaired by the Texas Land Commissioner, manages the CMP. On behalf of the Council, the General Land Office (GLO):

- Awards approximately 2.2 million annually in grants
- Reviews federal actions in the Texas coastal zone to ensure consistency with the goals and policies of the CMP
- Supports protection of natural habitats and wildlife
- Provides baseline data on the health of gulf waters

GLO Administers:

- **Grants Program**: awards National Oceanic and Atmospheric Administration (NOAA) grant funds to local entities for projects that support access to beach, bays, and other coastal natural resources areas
- **Non-point Source Pollution Control Program**: supports and protects natural habitats and wildlife by identifying sources of coastal non point source (NPS) pollution and developing recommendation for its prevention.
- **Coastal Permit Service Center (PSC)**: provides direct access to permitting agency staff and offering project specific technical assistance during the pre-application process;
- **Beach Watch Program**: provides Texans with baseline data on the health of the Gulf waters by analyzing water samples.
- **Coastal Impact Assistance Program** (CIAP): Funding of two hundred and fifty million dollars divided annually among the coastal states of Alabama, Alaska, California, Louisiana, Mississippi and Texas for fiscal year 2007, 2008, 2009 and 2010.
- **309 Coastal Management Program Enhancement Funds**: funding available to fund projects related to wetlands, coastal hazards, public access and other impacts.

GLO Coordinates:

- **Federal Consistency Review**: the review of federal coastal projects to ensure that they meeting state standards outlined inthe coastal zone management plan through a process called federal consistency review. Federal consistency review is required for most projects that 1) are in or can reasonably be expect of affect a use or resource of the Texas coastal zone; and/or 2) Require certain federal licenses or permits, receive certain federal funds, or are a direct action of a federal agency.
- **Coastal Preserve Program**: is designed to protect unique

coastal areas and fragile biological communities, including important colonial bird nesting sites.

GLO Participates In:

- **Artificial Reef Program:** planning and development of artificial reefs in a cost effective manner to support fishery management.
- **Resource Management Codes**: codes assigned to state tracts assist potential bidders by providing the best available information on natural resource concerns that may be associates with leasing the tracts of state owned land.

Additional Resources:

Texas Beach & Bay Access Guide
Texas Administrative Code: rules that help guide decision-making by entities that regulate or manage natural resource use on the coast
Coastal Natural Resource Areas (CNRAs)
Texas Coastal Wetlands
Coastal Coordination Council
Publications: produced for the CMP with federal funding from NOAA
Maps and Aerial Photography of the Texas Coastal Zone
GIS Data of the Coastal Zone from the GLO

For more information, please contact the Coastal Coordination Council at 1-800-998-4GLO or (512) 463-9212.

Last updated on 29 January 2010.

For more information, contact us.

CHAPTER 19

Hydropower

INTRODUCTION

Hydropower is the most common source of renewable electricity in the United States. In 2005, even with the recent expansion of the renewable energy sector from sources such as wind, solar and biomass, hydropower still comprised 73 percent of the nation's renewably generated electricity.

Hydropower is the most common source of renewable electricity in the United States.

Large-scale hydroelectric power generation is, however, concentrated in certain geographic regions in the U.S., most notably the Pacific Northwest.[1] Texas hydroelectric power has played an important role in the past, particularly in bringing electricity and jobs to rural areas of the state in the mid-1900s. Currently, however, it is a tiny portion of the state's electricity supply with little economic impact and limited prospects for expansion.

History

Human beings have harnessed the power of moving water for millennia, originally for purposes such as grinding grain and sawing wood. They have been employing its power to generate electricity since the 19th century, near the very beginning of the electric age. For example, Niagara Falls, New York began powering its street lights with hydroelectricity in 1881. In the following year, the world's first hydroelectric power plant opened in Appleton, Wisconsin.[2]

Until the development of effective transmission technology in 1893, however, hydroelectricity was limited to uses near its water source.[3]

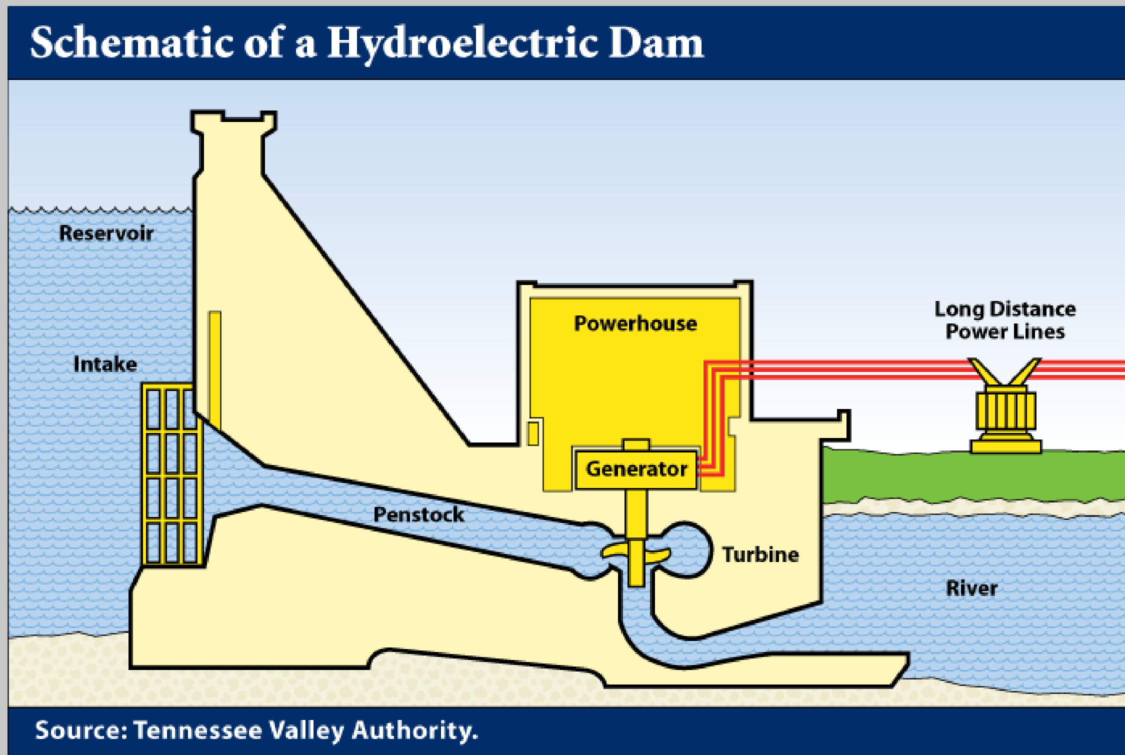
Uses

Most American hydroelectric power is generated through the force of falling water, by damming a stream or river to raise its water level and then allowing the water to fall against a turbine connected to a generator. Thus, the potential energy of the elevated water is transformed into kinetic energy of the falling water, which becomes mechanical energy in the turbine, and transformed again into electric energy in the generator (**Exhibit 19-1**).

Another type of what is called "conventional" hydroelectric power comes from "run-of-river" facilities that rely on the strength of the river's flow to drive turbines, without raising the water level with a dam. To provide significant amounts of electricity in this way requires a fast-flowing river, usually found in steep terrain or where a large stream is confined in a narrow bed.

Hydroelectricity made its largest impact on Texas in the mid-1930s, as part of the rural electrification efforts of the New Deal.

Exhibit 19-1

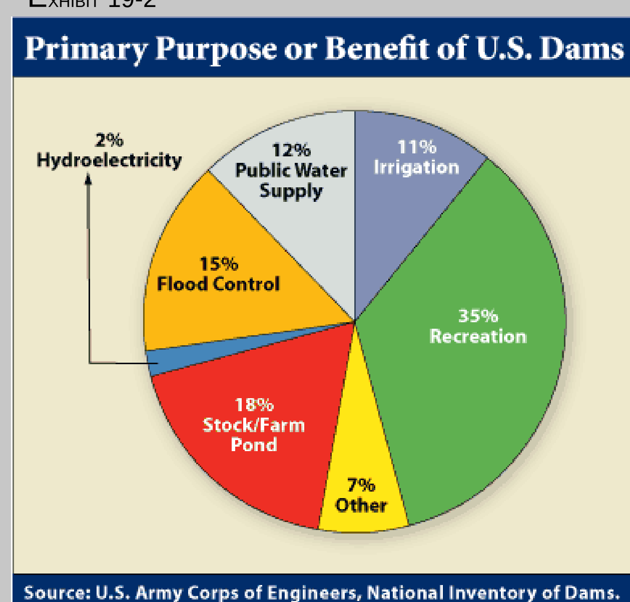


[View Exhibit 19-1: Schematic of a Hydroelectric Dam in Text Format.]

Still another form of hydroelectric power is created through what is called "pumped storage," in which water is moved from a lower-elevation storage facility (either a reservoir or a purpose-built container) to a higher elevation for release during peak demand. Although pumping the water uphill consumes more electricity than is generated by the water flowing back down, the financial return for the peak power is higher than the cost of pumping water during off-peak times.[4] Furthermore, this procedure can be used to store the energy from intermittent or variable sources such as wind and solar power, a technical challenge receiving a lot of attention; this use for pumped storage is currently being tested in Europe.[5] Consequently, hydroelectric power in this pumped-hydro configuration becomes an enabler for bringing online greater capacity from non-hydroelectric renewable sources.

For most common types of hydroelectric power, the amount of electricity generated is in direct proportion to the volume of water in motion and the distance it falls; in other words, doubling the amount of water or the height of the water's fall will double the amount of electricity that can be produced.[6] Because of the site requirements for power production, most dams in the U.S. do not generate any electricity, but instead were built for flood control and irrigation (**Exhibit 19-2**).

Exhibit 19-2



Hydropower requires no transportation or fuel combustion. As with other methods of generating electricity, transmission capacity is needed to deliver hydropower to the electric grid. Most hydroelectric plants have been around for so long, however, that their transmission infrastructure is well established. If an existing plant were to require new transmission capability, issues of access, rights of way and property ownership might arise. In the case of new dams and reservoirs, however, developing transmission lines is a minor obstacle compared to site selection, land acquisition and potential displacement of people, property and wildlife.

View Exhibit 19-2: Primary Purpose or Benefit of U.S. Dams.

Hydropower in Texas

Hydroelectricity made its largest impact on Texas in the mid-1930s, as part of the rural electrification efforts of the New Deal.[7] With the fresh example of the federally funded Tennessee River Authority's hydroelectric dams, and aided by the considerable political clout held by Texans in Washington, the Lower Colorado River Authority (LCRA) was able to build four of an eventual six dams on the Colorado River between 1935 and 1941.[8]

Economic Impact

Hydroelectricity brought jobs as well as electricity to the Hill Country and other areas of the state. Nevertheless, other sources of power soon dwarfed the contribution of dams. At the end of 1946, 15 percent of Texas' electricity came from hydropower; its share fell to less than half of that within about seven years.[9]

Because reservoirs in Texas are used primarily for water storage, dam operators can choose to release water through the power plant at the times when the resulting electricity is more valuable. Consequently, hydropower often is used to supplement the electrical grid during times of peak demand; the power plants can start generating within seconds. Hydropower's availability for use during peak demand enhances its economic value, but in largely semi-arid Texas, water usually is not released from reservoirs solely to generate electricity, so its economic potential is not always realized.

In the long run, the role of Texas dams in controlling flooding and preventing property damage has proven more economically important to the state than hydroelectric power.

Production

In current usage, "hydropower" refers solely to electricity generated by water, most often through a dam. As of 2006, Texas has only 23 dams with hydroelectric power plants out of hundreds of medium to large dams around the state. These 23 dams have a total generating capacity of 673 megawatts (MW), although the amount of electricity they actually produce annually is well below the maximum potential of generating 100 percent of the time. In 2004, Texas hydropower plants operated at an average 22 percent capacity factor, and in 2006 the capacity factor averaged only 11 percent. Hydropower production is limited by droughts or other factors that affect surface water flows.[10]

Availability

Most of Texas' terrain does not lend itself to large-scale hydroelectric projects. In 2004, hydro accounted for 0.62 percent of the state's electrical capacity and only 0.34 percent of electricity actually produced.[11] In the absence of additional hydroelectric plants, these percentages will continue to shrink as the state's overall generating capacity grows.

While Texas has some identified potential for additional hydroelectric capacity, the likelihood of its development is not high. Reservoirs can face opposition from the public and policy-makers, and all the new reservoirs being proposed by water planners are intended for storing water supplies. (It should be noted, however, that some of the state's water supply – about 1.5 percent of all Texas water consumed in 2004 – is consumed by traditional power plants in the process of generating electricity.) Even if all of the state's potential hydroelectric sites were dammed and supplied with generators, the total capacity would still be less than 1.5 percent of the current state total. Texas simply does not have many big-river/big-drop settings that would justify overcoming the hurdles of land acquisition, construction cost and ecosystem destruction inherent in dam building and reservoir creation.

More than 12 percent of Texas' hydropower capacity belongs to the Sabine River Authority, which lies in the Southeastern Electric Reliability Council region rather than that of the state's main power grid, the Electric Reliability Council of Texas (ERCOT). Another 10.4 percent of the state's generation capacity flows into the part of the Southwest Power Pool grid, which covers most of the Panhandle and parts of Northeast Texas. LCRA owns six of the 22 hydroelectric plants that feed energy into the ERCOT grid; these comprise more than 65 percent of ERCOT's hydro-generating capacity. Plants owned by the U.S. Corps of Engineers and various river authorities provide the remainder.[12]

Costs and Benefits

The cost of generating hydroelectric power lies almost entirely in the construction of the dam and power plant.[13] Once in place, its costs are largely limited to equipment maintenance, with no further costs for fuel and its transportation, so operating expenses for hydroelectric plants are significantly lower than those for other conventional power plants.

The cost of generating hydroelectric power lies almost entirely in the construction of the dam and power plant.

As long as there is sufficient water to run the turbines, electricity can be produced very cheaply. Compared even to mature nuclear plants, hydropower costs less than half as much to produce, at under 0.9 cents per kilowatt-hour (kWh).[14] It then joins the stream of power transmitted and sold in the wholesale and retail markets at the same prices as electricity generated by other means, complete with premiums for peak demand production.

But dams and reservoirs are expensive to build. The cost of the proposed Marvin Nichols reservoir in northeast Texas, for example, has been estimated at $2.2 billion, with no power plant included.[15] And water dammed for use in city water systems is unlikely to be released for other purposes, even to generate low-cost electricity.

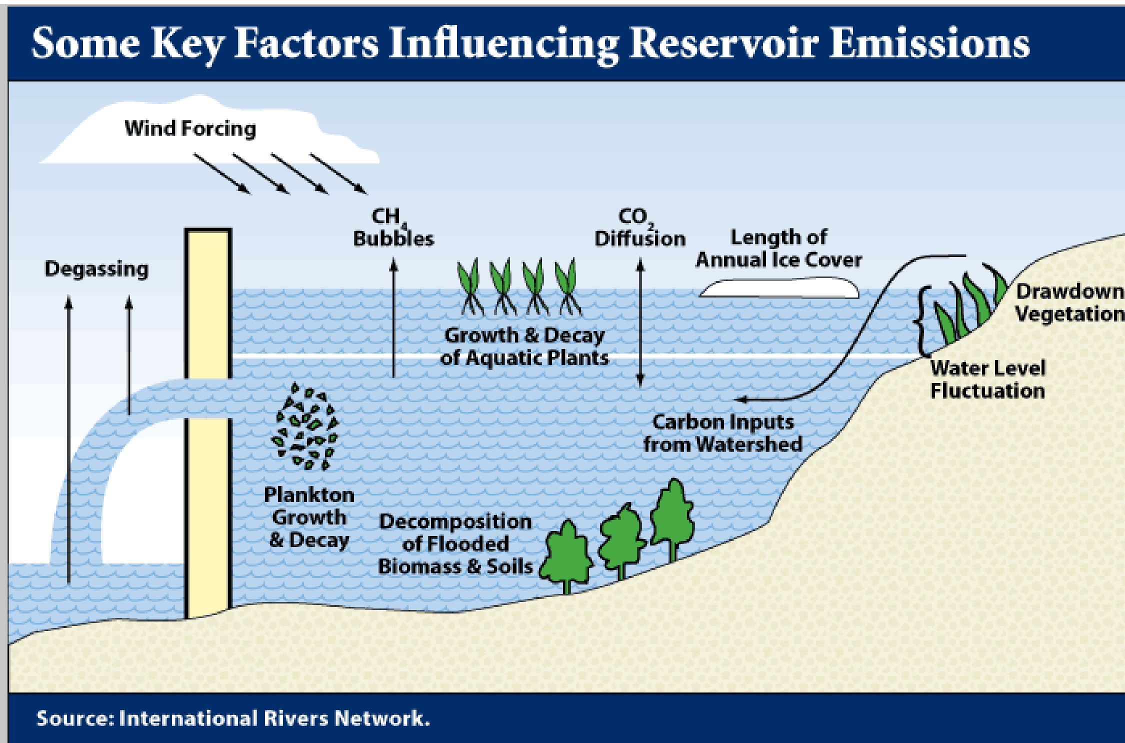
Environmental Impact

The environmental impact of hydropower is mixed. Although a hydroelectric plant uses the motion of water as a renewable fuel, *gathering* that water can have a large impact on the environment. The most obvious impact is the destruction of a river ecosystem and its replacement with a reservoir. This displaces flora and fauna as well as human inhabitants, and disrupts any activity dependent on aspects of the prior ecosystem, such as bottomland timber. In addition, below the dam the instream flow (the amount of water left flowing in the river) is affected, as are downstream water users and bays and estuaries at the coast. And, because reservoirs created behind dams vastly expand the surface area of the water body, evaporative water loss increases significantly.

Reservoirs also collect sediment, concentrating nutrients as well as pollutants; eventually (as can be seen in older Texas reservoirs) these sediments build up, making the reservoirs shallower.[16] And recent research has found that reservoirs and hydroelectric dams, previously thought of as zero-emissions power sources, actually do emit greenhouse gasses, particularly methane from the decomposition of organic materials (**Exhibit 19-3**).[17] Although scientists are debating how much gas is released and under what conditions, there is little disagreement about the fact that it occurs. This phenomenon is particularly relevant in tropical locations with large reservoirs that contain significant amounts of buried biomass.[18]

Exhibit 19-3

Hydroelectricity supplies a very small percentage of Texas' power supply, and that percentage is shrinking as total generating capacity grows.



View Exhibit 19-3: Some Key Factors Influencing Reservoir Emissions in Text Format.

More study is required to accurately compare the environmental impacts of hydroelectricity with other power sources.[19] Some have even proposed ways to tap the methane in reservoirs for use in power production.[20] Overall, hydroelectric dams remain a low-emission method of generating electricity compared to fossil fuel power plants and, as noted at the beginning of this chapter, the largest source of renewable electricity in the United States.

Other Risks

If a dam breaks due to extreme rainfall or inadequate maintenance, it can cause great damage downstream. The safety of aging dams has been the subject of a considerable amount of discussion both domestically and worldwide. The fact that a fairly large portion (25 percent or more) of dams included in the National Inventory of Dams are at least 50 years old is a concern, particularly in light of subsequent improvements in design and construction standards.[21]

State and Federal Oversight

If any new hydroelectric plants were built, most of the laws affecting them would concern the dam and reservoir rather than the generating plant. In Texas, the water in rivers belongs to the state, and state regulation covers dams and reservoirs unless they are built on federal land. Federal environmental regulations concerning wetlands and wildlife protection also could come into play, depending on the site.

Subsidies and Taxes

Hydropower is such a mature technology that it often is not even included in discussions and incentive programs for renewable energy. Nevertheless, renewable energy tax credits are available for hydroelectric power production, and federal ownership of a number of dams allows the U.S. government to set subsidized prices for the electricity they produce. More information on this topic can be found in Chapter 28.

Other States and Countries

Texas has no plans for new hydroelectric facilities, and, according to the Energy Information Administration, through 2010 only four states will add new hydroelectric capacity, for a total additional 16 MW of capacity.[22]

Hydroelectric capacity is still expanding in other parts of the world, with the largest growth occurring in Asia, particularly China and India, and in Central and South America and Canada.

China has several large projects under way, including Three Gorges, which will provide 18,200 MW of hydroelectricity capacity by 2009, and India is adding over 13,000 MW in the next few years. In countries that already rely heavily on hydropower, such as Brazil, greater emphasis and investment is expected on the diversification of electricity sources.[23] Even so, the current administration in Brazil is pushing for large new hydroelectric projects in the Amazon region, stirring much controversy.[24]

Outlook for Texas

Hydroelectricity supplies a very small percentage of Texas' power supply, and that percentage is shrinking as total generating capacity grows. Although the state has some limited potential for additional hydropower, there are no current plans to develop it. The new reservoirs being planned for the state do not include electric generation plants; those plans are about water, not power.

While existing facilities may be able to increase their generating capacity due to efficiency improvements from new turbines or other factors, these gains are likely to be modest. The amount of hydroelectricity Texas generates this year and into the future is more likely to depend on the weather – floods or droughts – than on state demand for electricity. In all likelihood, hydropower has reached its peak in Texas.

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Chapter 15

Wood

Introduction

Wood is an excellent source of energy. It can be used to create biofuels, burned directly, turned into a synthetic gas or pyrolyzed – turned into a liquid to create electricity.

Potential fuel sources for wood-fired power plants include mill residues, sawdust, wood trimmings and construction debris.

Wood-fired power plants can have a positive impact on the economy of some rural areas. At present, Texas has no operating wood-to-electricity facilities, but two are being developed. Nacogdoches Power is building a large wood-burning facility in Sacul, Texas expected to be operational in late 2009. And Mesquite Fuels & Agriculture in Hamlin, Texas plans to establish a smaller-scale wood-gasification facility expected to be operational in spring or summer 2008.[1] These facilities are projected to add about 500 jobs to all sectors of the economy once completed.[2]

Potential fuel sources for wood-fired power plants include mill residues, sawdust, wood trimmings and construction debris. East Texas, home to much of the state's lumber industry, has a particularly large resource base. In 2005, East Texas wood products companies produced 9.5 million tons of logging and mill residues.[3]

History

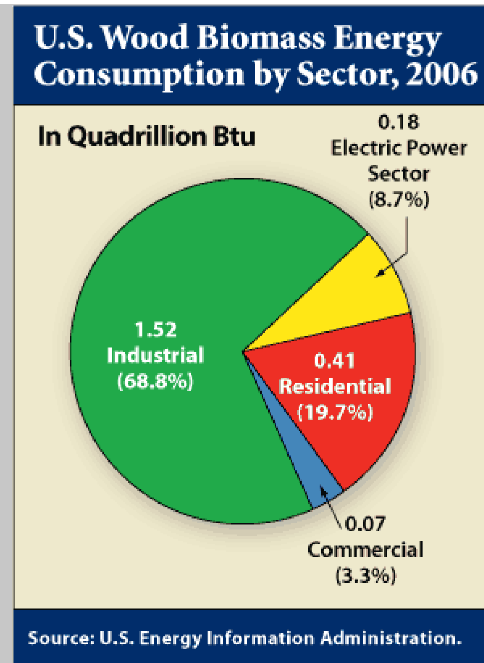
Exhibit 15-1

Biomass is the oldest human energy source. Mankind has burned wood to create heat for tens of thousands of years. By 1890, commercial, residential and transportation sectors counted on wood as the primary fuel supply. The first power plant to generate electricity from wood was the Joseph McNeil generating station in Burlington, Vermont in 1984.[4]

Uses

Biomass (including organic waste, fuels derived from plants and wood) recently surpassed hydroelectric power to become the largest source of renewable energy in the U.S.

Industrial consumers use the majority of the energy



[View Exhibit 15-1: U.S. Wood Biomass Energy Consumption by Sector, 2006 in Table Format.]

In the most common method of electricity generation from biomass, wood waste, is burned in a manner similar to coal or gas firing in a power plant.

generated from biomass. Most of this energy is generated at mills or paper plants that burn their own wood waste for power and heat (**Exhibit 15-1**).

Biomass can be used to create electricity through a variety of methods, including direct firing, gasification and pyrolysis (the liquefaction of biomass to form an oil), among others. Direct firing is the most common of these methods.[5] Although other chapters in this report focus on municipal solid waste and landfill gas; this chapter is devoted to wood biomass only. Electricity generated from wood-fired biomass can be placed on the power grid for residential and commercial use, or used at the source of generation.

Wood Biomass in Texas

Texas produces an estimated 20 million tons per year of biomass that can be used as fuel. This includes forest residues, mill residues, urban wood waste, agricultural residues and dedicated energy crops.[6] According to Mark Kapner, a senior strategy engineer at Austin Energy, this is the equivalent of about 4,600 megawatts (MW) of potential capacity, enough to power more than 2.5 million homes in Texas, based on average electric use in 2006.[7] The U.S. had 6,372 MW of installed capacity (on the grid) of wood-fired biomass in 2006. This is up from 5,844 MW in 2002.[8]

Economic Impact

A 1999 study by the National Renewable Energy Laboratory (NREL) stated that 4.9 full-time jobs are created by every megawatt of generating capacity.[9] Applying this figure to the estimated 4,600 MW of total potential capacity in Texas indicates that the wood-fired energy industry could add more than 22,000 jobs to the state.

A 100 MW wood-fired biomass power plant being developed by Nacogdoches Power in Sacul (discussed below) is expected to create about 490 new jobs.[10] The 8 MW wood gasification power plant being developed by Mesquite Fuels & Agriculture in Hamlin will employ eight to nine people, with additional employees needed to harvest wood. Mesquite Fuels & Agriculture anticipates that employees will be paid between $10 and $14 per hour.[11]

Consumption

Again, Texas currently has no operational wood-fired biomass power plants, although two Texas plants are planned.

Producing Electricity from Wood using Gasification and Pyrolysis

Gasification and pyrolysis are similar processes. Both require high temperatures and a oxygen-limited environment.

Gasification

Gasification converts biomass to combustible gases by heating it at high temperatures in an oxygen-limited environment. The resulting "synthesis" gases contain hydrogen and carbon monoxide.[16] Synthesis gases are mixed with oxygen and burned to heat water and produce steam to turn a turbine and create electricity. Synthesis gases can also be used in gas turbines or converted into other fuels.[17] Gasification of biomass removes pollutants such as ash and other particulates.[18]

Pyrolysis

Pyrolysis is used to convert biomass to a liquid.

In 2006, energy from wood-fired biomass accounted for 2.1 quadrillion Btu, in the U.S., about 31 percent of all renewable energy consumed.[12]

Heating biomass at extremely high temperatures (more than 1,000°F) in an environment with no oxygen produces vapors that can be condensed into a liquid called pyrolysis oil. This oil, a renewable liquid fuel, can be stored and transported easily.[19] It can be burned to create electricity or used to produce chemicals, plastics and other products.[20]

Production

Most direct-fired biomass plants burn wood waste derived from sources such as mill residues, sawdust, wood trimmings and construction debris. This biomass can be burned alone or co-fired with fossil fuels. In the latter case, biomass generally replaces only a small portion of the fossil fuel (about 20 percent).[13]

In addition to trimmings collected off the forest floor after logs are harvested, forests can be "pre-trimmed" prior to logging. This "pre-commercial" trimming can produce biomass for electricity while decreasing the risk of forest fires and insect and disease attack.[14]

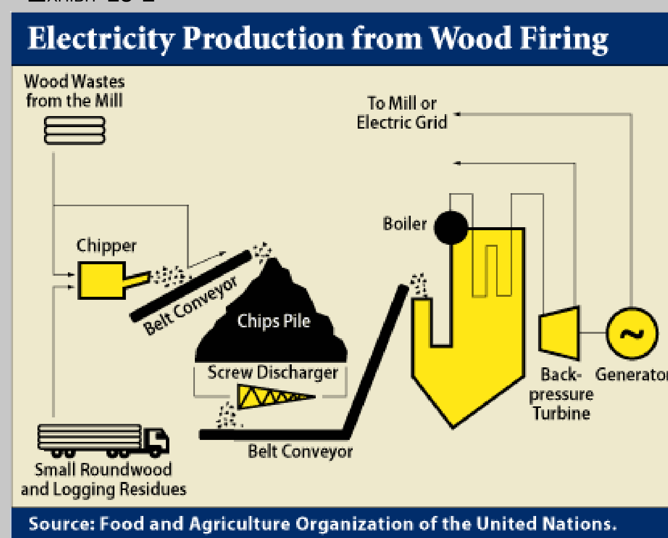
Transportation

Wood-fired biomass power plants usually are located near areas with large amounts of wood waste, to reduce or avoid the cost of transportation. (Transportation costs often account for the majority of the cost of any fuel.) To be economically feasible, wood-fired power plants generally are located within about 50 miles of the wood source.[15]

Power Generation

In the most common method of electricity generation from biomass, wood waste is burned in a manner similar to coal or gas firing in a power plant. The waste is sent through a chipper and then to a boiler where it is burned to heat water, producing steam. The resulting steam spins turbines, which in turn drive generators to produce electricity (**Exhibit 15-2**). In co-firing, fossil fuels and wood waste are burned together to create steam. The wood waste may need to be dried prior to burning to reduce its moisture content.

Exhibit 15-2



View Exhibit 15-2: Electricity Production from Wood Firing in Text Format.

The wood-fired biomass power plant proposed for Sacul, a small town near Nacogdoches, will employ a fluidized bed combustion boiler (FBC).[21] In an FBC, a layer of sand is heated and agitated using upflowing jets of air. The heated sand is used to distribute air evenly throughout the chamber. Wood waste then is injected into the boiler. The jets of air suspend the wood in midair, allowing it to burn on all sides, yielding a more efficient combustion process.[22]

Burning wood biomass for electricity can help to reduce the amount of wood waste sent to landfills.

Selective non-catalytic reduction (SNCR) systems can be used to control wood-fired emissions of NO_X, a known greenhouse gas with adverse health and environmental effects.[23] SNCR involves a chemical reaction that employs NO_X rather than oxygen as its primary reactant. SNCR works by injecting either ammonia (NH_3) or urea into the gas produced during combustion. NO_X then undergoes a reaction in the presence of oxygen; the oxygen is removed from the NO_X and bonds to the hydrogen from ammonia or urea, forming nitrogen gas (the most common gas in the atmosphere) and water vapor. SNCR can reduce NO_X emissions levels by 30 to 75 percent.[24]

Although only a portion could be used for energy generation, Texas has a very large biomass resource base.

Storage and Disposal

Burning wood biomass for electricity can help to reduce the amount of wood waste sent to landfills. Wood waste can be stored in a variety of ways, depending on the scale of the plant and the fuel's moisture content: in open uncovered wood piles, partially covered wood piles (open sheds), or enclosed wood piles (storage bins, hoppers, or silos).[25] Foreign debris in the wood waste, such as stones, nails and other metal, must be removed prior to use.[26]

Availability

Although only a portion could be used for energy generation, Texas has a very large biomass resource base, with more than 12 million acres of forests, mostly of pine, in 43 counties in East Texas alone.

More than 90,000 Texans work in the state's $2.3 billion forest products industry. Texas has more than 1,200 lumber and wood-product mills.[27]

Many sites in the state, such as mills, use wood waste to heat and power their own facilities.

The 100 MW wood-fired biomass power plant being developed in Sacul, located in Nacogdoches County, will use logging residue as its main fuel source, but also could use urban wood waste. Nacogdoches Power estimates that the plant will require 1 million tons of biomass per year.[28] It will be the largest wood-fired power plant in the nation, according to Nacogdoches Power.[29]

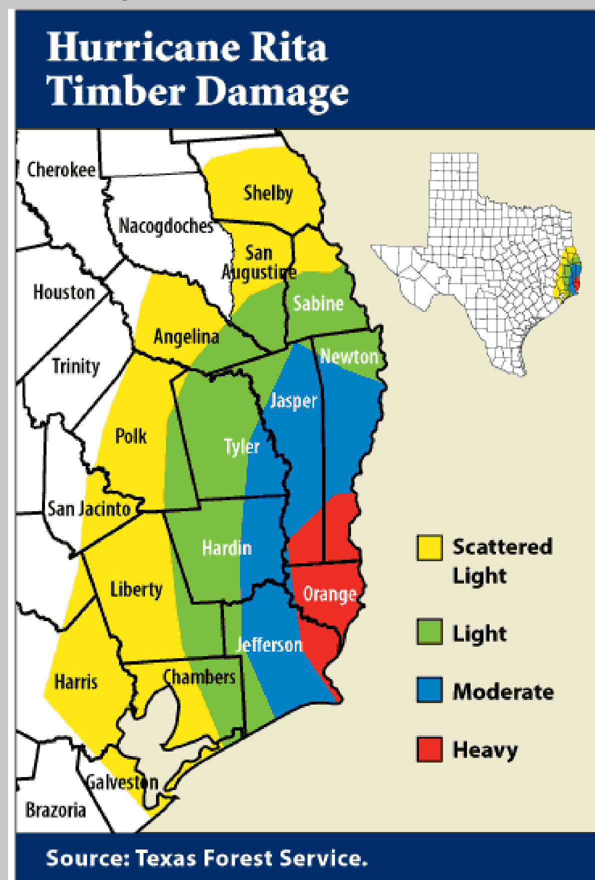
Exhibit 15-3
Logging and Mill Residue in East Texas, 2005
(tons)

Type of Wood	Logging Residue (green tons)	Mill Residue (dry tons)	Total (tons)
Hardwood	1,035,334	978,342	2,013,676
Softwood	2,102,947	5,333,589	7,436,536
Total	3,138,281	6,311,932	9,450,213

Note: Numbers may not total due to rounding.

Sources: Texas Comptroller of Public Accounts and Texas Forest Service.

Exhibit 15-4



[View Exhibit 15-4: Hurricane Rita Timber Damage in Text Format.]

In 2005, 3.1 million green tons of logging residues were available for use in East Texas, as well as 6.3 million dry tons of mill residues (**Exhibit 15-3**). Mill residue is already being used; it can be burned to power and heat mills or sold for landscaping materials, sawdust or pulping material. On the other hand, most logging residue is simply left at the logging site and this, too, could be sold for energy production.[30]

The energy content of this material will vary depending on its moisture content. The moisture content of raw wood that has just been cut is typically between 30 and 40 percent.[31]

Trees damaged in the wake of Hurricane Rita could have been used in a wood-burning power plant. Hurricane Rita caused more damage to East Texas timber than any disaster in recent history, destroying or damaging about 6 percent or 771,000 acres of East Texas timber (**Exhibit 15-4**).[32]

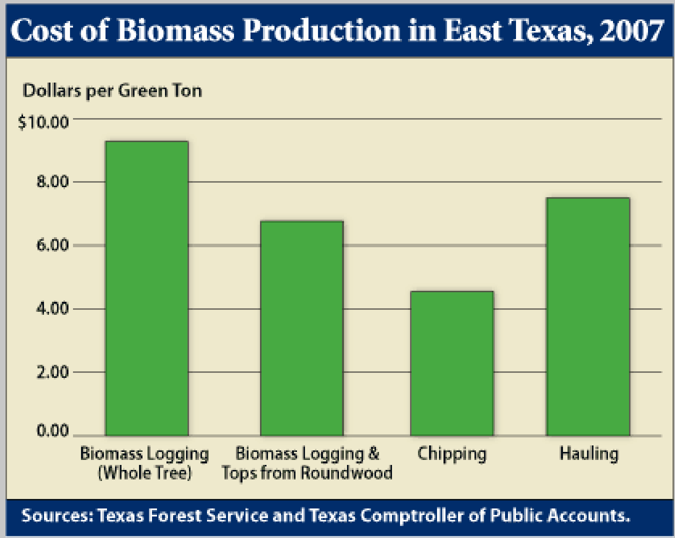
The 2007 Texas Legislature directed the State Energy Conservation Office (SECO) to update a 1995 assessment of Texas renewable energy resources. This report, which will be released before the start of the 2009 Texas legislative session, will include up-to-date data on the availability of various renewable energy resources, including biomass.

Costs and Benefits

Prices for electricity generated from wood-fired power plants tend to range from 5 cents to 7 cents per kilowatt hour (kWh), with a national average cost of about 6 cents.[33] This price includes incentives that are available for this type of electricity generation, including a 1 cent to 2 cent per kilowatt-hour (kWh) federal renewable energy production credit on corporate income tax. More information on this incentive is found in the Incentives, Subsidies, Taxes and Tariffs section of this chapter.

The Sacul plant will cost about $400 million to build, or about $4,000 per installed kilowatt. In addition to construction costs, the costs of fuel and chipping and transporting it must be considered (**Exhibit 15-5**). For example, a ton of chips produced from whole trees would cost an average of $21.35. This figure includes an average cost of $9.29 per ton for the wood, $4.56 per ton for chipping and $7.50 per ton for transporting the wood. In addition, drying costs may be significant depending on the wood's moisture content.

EXHIBIT 15-5



View Exhibit 15-5: Cost of Biomass Production in East Texas in Table Format.

While Nacogdoches Power officials did not provide their expected costs, in Oregon and other areas of the Pacific Northwest, wood-fired electricity costs from 5.2 cents to 6.7 cents per kWh to produce.[38]

Environmental Impact

Wood-fired biomass power plants produce some air and water pollution. The grinding or chipping of wood creates dust, although wetting the wood before chipping can reduce dust levels. Furthermore, burning wood releases volatile organic compounds, or VOCs, which pose a health risk.[41] The amount of air pollutants, including NO_X and SO_2, emitted by wood burning power plants is significantly lower than those emitted by plants using coal.[42]

The amount of ash produced by burning wood varies depending on the type of wood wastes used. Clean chips containing no bark have a low ash content, typically less than 0.5 percent. Wood chips containing bark have a higher ash content of around 1 percent. Sawdust has a low ash content of around 0.5 percent.[43] Ash resulting from burning wood can be sold as a fertilizer or disposed of in landfills. Typically, softwoods such as pine have higher ash contents than hardwoods.[44]

Co-firing biomass with coal can reduce coal's harmful emissions.

On the other hand, co-firing biomass with coal can reduce coal's harmful emissions. In particular, co-firing can reduce sulfur oxides (SO_X), which produce acid rain, on a one-to-one basis; in other words, replacing 10 percent of coal with biomass reduces its SO_X emissions by 10 percent.[45]

Depending upon the plant type, electricity generation from wood biomass requires withdrawals of between 9 gallons and 14,655 gallons per million Btu of heat produced.[46] This is the amount of water extracted from a water source; most of the water withdrawn is returned to that source.

Water consumption refers to the portion of those withdrawals that is actually used and no longer available. Water consumption ranges from zero to 150 gallons per million Btu produced.[47]

Wood Gasification Plant in Texas

Mesquite Fuels & Agriculture is in the process of constructing a wood gasification facility in Hamlin, Texas, that is expected to open in spring or summer 2008. Hamlin is located about 40 miles northwest of Abilene. The facility will cost $2.5 to 3 million per MW; at 8 MW the facility is expected to cost more than $20 million. This facility will employ 8 to 9 people on a permanent basis, as well as other employees needed to harvest and transport wood.[34] The facility will employ gasification

Sugarcane Bagasse to Energy Project

The Rio Grande Valley Sugar Growers, Inc. is turning sugar cane waste into electricity. The facility, located in Santa Rosa, uses waste to produce electricity via steam turbines. Currently, the facility is undergoing a renovation to replace the boilers and turbines with newer, more energy efficient equipment. At an estimated cost of $26.5 million, the project will allow the facility to create enough electricity to run the sugar processing plant (about 9 MW) and to sell the remaining electricity on the grid technology to produce electricity from mesquite. Its generation capacity is expected to be 8 MW.[35]

The plant also will be able to generate steam that could be sold to other industrial consumers in the immediate area.[36] In addition to the first plant in Hamlin, Mesquite Fuels & Agriculture is examining other sites in West Texas, and believes there is enough mesquite in these areas for five or six more facilities.[37]

(about 4.5 MW).[39] In addition, the project will save an estimated 80 percent of natural gas purchases and 90 percent of electricity purchases. This, together with the revenue from selling electricity to the grid, will save an estimated $3.5 to $4 million annually. The use of sugarcane waste to create energy will also save on disposal costs and landfill space.[40]

Other Risks

During the Texas Forestry and Bioenergy Conference held in Nacogdoches in May 2007, participants discussed concerns about fertilizer use in the forestry industry. Logging residue provides natural fertilization for remaining trees as well as for new trees that may be planted at the same site. Foresters are concerned that removing these trimmings and other residues will require them to use more fertilizer, adding to their costs.

Finally, wood fuel typically is transported to the power plants by truck, leading to increased traffic in local areas, high transportation fuel costs and increased emissions. Increased truck traffic in areas without a robust transportation infrastructure leads to heavy wear and tear on existing rural roadways.

State and Federal Oversight

The federal Clean Air Act and Clean Water Act both affect wood-burning power plants. Wood-fired power plants are particularly affected by the National Ambient Air Quality Standards, which quantify the amount of particulate matter that a facility may generate, both in a 24-hour period and annually. Wood combustion produces fine particulate matter (2.5 micrometers in diameter or smaller). The standards also regulate course particulate matter (between 2.5 and 10 micrometers in diameter), such as the dust generated by truck traffic.[48]

The Texas Commission on Environmental Quality grants permits for air and wastewater quality. As with other electricity generation facilities, wood biomass plants require other permits including wetland impact permits, a threatened and endangered species permit and an acid rain permit. Permits required vary by geographical location.

Subsidies and Taxes

The federal Renewable Electricity Production Tax Credit, established in 1992 and extended and renewed several times, is a corporate income tax credit that provides an annually adjusted incentive to utilities that produce power from renewable sources. In 2008, the incentive is 2.0 cents per kWh for many renewable sources such as wind, geothermal and closed-loop biomass (see sidebar). A smaller incentive of one cent per kWh was available for energy produced using open-loop biomass, small irrigation hydroelectric power (generated without a dam and with a capacity of between 150 kW and 5 MW), landfill gas and municipal solid waste.[49]

The 2007 Texas Legislature's House Bill 1090 creates incentives of up to $30 million annually to support electricity produced from biomass and made available to the state's electric grid. H.B. 1090 will provide subsidies of $20 per bone-dry ton of wood, up to $6 million per year, for each qualifying entity.[50] This incentive will be given to wood suppliers (loggers, mills and landfills), who could in turn pass along lower fuel costs to electricity generators. Funding for this program will require an appropriation and will not begin until 2009 at the earliest.

Another 2007 bill, H.B. 1214, would have strengthened the current law stating that 500 MW of renewable power in Texas should come from a source other than wind, making it a requirement rather than a suggestion, but the bill did not pass.

The Energy Policy Act of 2005 defines Closed and Open Loop Biomass:

Closed-loop Biomass: any organic material from a plant that is planted exclusively for use at a qualified facility to produce electricity.

Open-loop Biomass: any agricultural livestock waste nutrients or any solid, nonhazardous, cellulosic waste material or nonhazardous lignin waste material that is segregated from other waste materials and derived from forest-related resources, including mill and harvesting residues, precommercial thinnings, slash and brush or solid wood waste materials. This does not include municipal solid waste, gas derived from the biodegradation of solid waste, paper that is commonly recycled or biomass used in co-firing.

Source: Energy Policy Act of 2005.

More information on subsidies and incentives for wood biomass can be found in Chapter 28.

Other States and Countries

Many states operate wood-fired biomass power plants. California and Michigan have several smaller-scale sites in the range of 10 to 35 MW.[51]

One of the most successful wood biomass operations is the Joseph C. McNeil Generating Station in Burlington, Vermont, a 50 MW electricity plant mostly powered by wood. The facility consumes 180,000 tons of wood per year. Seventy percent of this comes from "low-quality" trees; 25 percent from chip and bark residues; and 5 percent is clean recycled wood. McNeil estimates that the wood it uses costs about $12 to $20 per ton. The facility also has a waste yard where individuals can dispose of wood and yard waste. It sells wood ash to a contractor who mixes it with limestone as a soil conditioner.[52]

Outlook for Texas

Wood-fired biomass has some potential for Texas, particularly East Texas, which has enough potential capacity to produce the majority of the state's suggested goal of 500 MW of non-wind renewable energy capacity. The main obstacle to wood-fired biomass power plants is economic. Without incentives and subsidies, the cost of the fuel is too high to make such plants profitable.

Furthermore, some oppose the use of wood waste for electricity generation. As already noted, some Texas foresters believe that gathering logging residue off the forest floor may require them to use more fertilizer to grow trees, although further study of this issue is needed.

Wood-fired biomass has some potential for Texas, particularly East Texas.

Some Texas mills and paper plants believe that Texas' incentives and subsidies for biomass-generated electricity are unfair.[53] Again, many mills and paper plants produce electricity for their own use from their own wood waste, yet this electricity is not eligible for state incentives and subsidies because it does not go to the power grid.[54]

Other critics oppose a state mandate requiring non-wind renewable sources such as wood-fired biomass because they believe that it will cost more than electricity generated from other sources.[55] Electricity generated from biomass that is placed on the grid becomes part of the mix of the state's energy portfolio; electricity consumers generally do not get to choose from which source their electricity is generated.

Wood-fired biomass may never comprise more than a small percentage of the state's energy portfolio, but it could create jobs in rural areas and stimulate the local economy in East Texas.

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CHAPTER EIGHTEEN — *Municipal Waste Combustion*

CHAPTER 18

Municipal Waste Combustion

INTRODUCTION

Some cities, primarily in the northeastern and mid-Atlantic U.S., burn part of their municipal solid wastes. Hemmed in by major population centers, landfill space there is at a premium, so burning wastes to reduce their volume and weight makes sense. Combustion reduces the volume of material by about 90 percent and its weight by 75 percent.[1] The heat generated by burning wastes has other uses, as well, as it can be used directly for heating, to produce steam or to generate electricity.

In Texas, municipal waste combustion facilities have had little to no economic impact on the state as a whole. Texas had two permitted waste incinerators in 2006, and one waste-to-energy facility in Carthage.[2] The Carthage plant is now owned by a private company that uses the facility to incinerate medical waste.

History

In 1885, the U.S. Army built the nation's first garbage incinerator on Governor's Island in New York City harbor. Also in 1885, Allegheny, Pennsylvania built the first municipal incinerator. As their populations increased, many cities turned to incinerators as a convenient way to dispose of wastes.

Combustion reduces the volume of solid waste material by about 90 percent and its weight by 75 percent.

These incineration facilities usually were located within city limits because transporting garbage to distant locations was impractical. By the end of the 1930s, an estimated 700 incinerators were in use across the nation.[3] This number declined to about 265 by 1966, due to air emissions problems and other limitations of the technology. In addition, the popularity of landfills increased.[4]

In the early 20th century, some U.S. cities began generating electricity or steam from burning wastes. In the 1920s, Atlanta sold steam from its incinerators to the Atlanta Gas Light Company and Georgia Power Company.

Europe, however, developed waste-to-energy technologies more thoroughly, in part because these countries had less land available for landfills. After World War II, European cities further developed such facilities as they rebuilt areas ravaged by war. U.S. cities interested in converting waste to energy tended to acquire European technologies when they built or improved their incinerators.

In the 1970s, the Arab oil embargo and increasing energy prices encouraged the development of waste combustion. The U.S. Navy, for instance, built waste-to-energy plants at two Virginia naval stations, one of which is still in use.

Federal laws and policies aided the development of the waste-to-energy industry. The 1970 Clean Air Act authorized the end of open burning at U.S. landfills. City incinerators also were required to install pollution controls or cease operation, and a number of the worst polluters were closed down. Losing incinerators forced cities to consider waste-to-energy plants and look again to Europe for technology. In 1975, the first privately built waste-to-energy plant opened in Massachusetts; it experienced a number of operational problems at first as engineers sought to adapt it to the contents of American waste and made other operational changes.

In the late 1970s, the federal government started to fund feasibility studies for local governments interested in setting up new waste-to-energy plants.

The 1978 Public Utility Regulatory Policies Act (PURPA), which required the Federal Energy Regulatory Commission to guarantee a market for electricity produced by small power plants, allowed new waste-to-energy projects to find financing. PURPA made waste-to-energy projects financially viable, since projects could find buyers for the electricity they generated.[5]

The 1980 Energy Security Act appropriated funds to support biomass energy projects and required federal agencies to prepare a plan for maximizing its production and use. The act provided insured loans, loan and price guarantees and purchase agreements for biomass projects, including waste-to-energy projects using municipal solid waste. It also directed the U.S. Department of Energy to prepare a municipal waste energy development plan and support it with construction loans, and loan guarantees, price support loans and price guarantees. The act also authorized research and development for promoting the commercial viability of energy recovery from municipal waste.[6]

While the majority of this funding was rescinded in the 1980's, some federal money flowed to businesses and local governments, and about 46 new waste-to-energy facilities were built.[7]

The 1986 federal Tax Reform Act simultaneously benefited and harmed the development of waste-to-energy facilities. The act extended federal tax credits available for waste-to-energy facilities for ten years, but also repealed the tax-free status of waste-to-energy plants financed with industrial development bonds.[8]

The use of municipal waste combustion for energy is not common; the nation had only 87 such facilities in 2007.

In the 1990s, after the tax credits extended in 1986 finally ended, fewer waste-to-energy plants were built.

Uses

The heat generated by burning waste can be used directly for heating; to produce steam; or to produce electricity.

Municipal Waste Combustion in Texas

Space for landfills has been plentiful in the past, but is becoming harder to find in large urban areas. Recycling programs have reduced the amount of matter going into landfills, but combustion may become more viable in some urban areas if landfill sites become scarce or if energy prices make combustion more economically viable.

Economic Impact

Municipal waste combustion facilities in Texas have had little economic impact on the state as a whole. Texas sole permitted waste-to-energy facility does not produce electricity. At this time, the Sharps Environmental Service Solid Waste Incineration Facility has the capability of producing steam for sale, but it is currently operating the facility only as an incinerator.[9] A 50 MW waste-to-energy plant in Polk County, Florida, has an estimated $6 million annual regional economic impact, according to its operator, Wheelabrator Ridge Energy, Inc.[10] A similarly-sized plant in Texas would have comparable economic impact.

Consumption

The use of municipal waste combustion for energy is not common; the nation had only 87 such facilities in 2007.[11] Even so, about 31.4 million tons of solid waste were channeled to these plants in 2006, representing 12.5 percent of all municipal solid waste disposal.[12]

Texas' sole permitted waste-to-energy facility processed 387 tons of waste in 2006.[13]

In addition, a 2006 agreement between two energy contractors will lead to the development of another waste-to-energy power plant supplying Dyess Air Force Base in Abilene.[14] About a third of Abilene's solid waste – some 35,000 tons a year – will be fired, along with garbage from the base and the nearby city of Tye. Dyess will buy discounted energy from the contractor operating the waste-to-energy plant, saving nearly half of its current energy costs.[15] The Air Force contract totals over $39 million and includes the waste-to-energy plant plus diesel back-up generators.[16]

Production

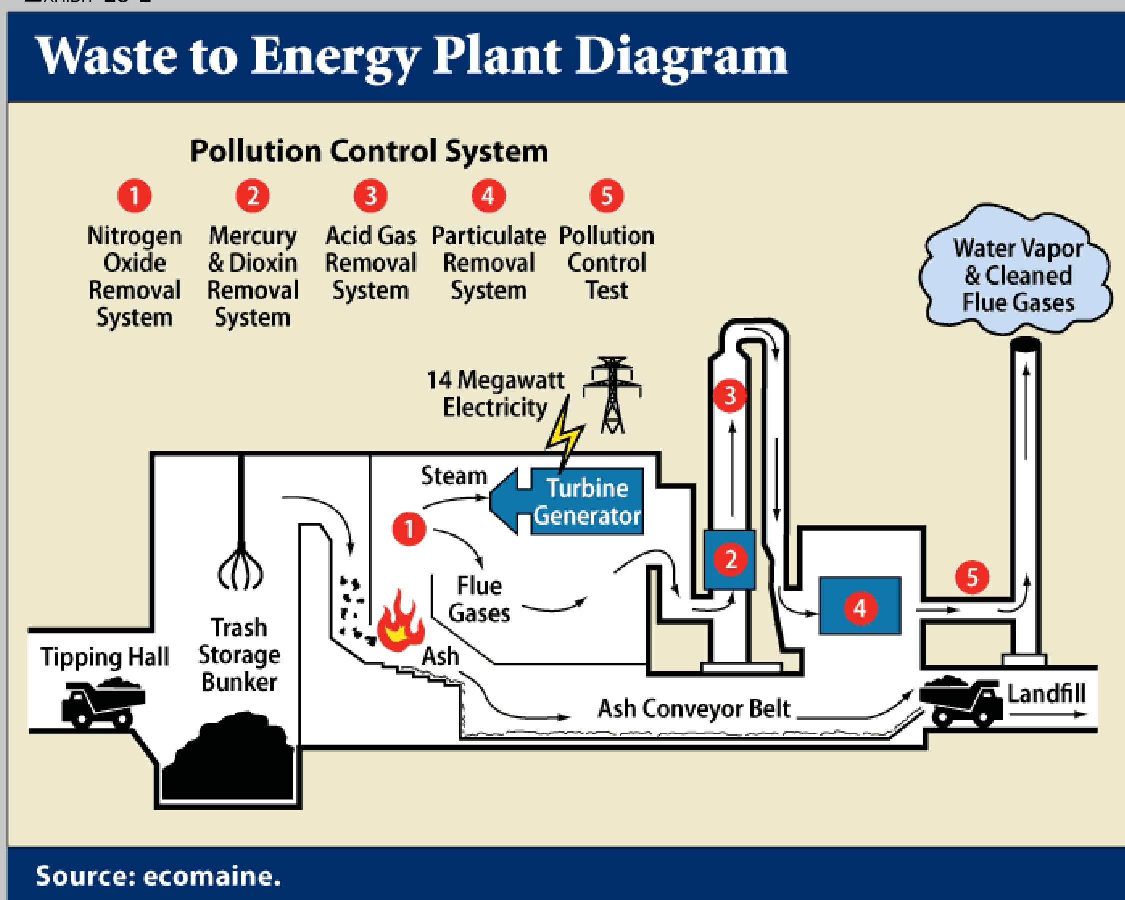
Waste-to-energy facilities tend to be built near the landfills of large urban centers. A few facilities are modular units, smaller plants built off-site and transported to wherever they are needed.

Waste-to-energy plants generate electricity by burning municipal wastes in large furnaces to produce steam, which in turn drives a steam turbine to generate electricity. On average, one ton of waste produces 525 kilowatt-hours (kWh) of electricity. This is equivalent to the energy produced by a quarter-ton of coal or one barrel of oil.[17]

One type of waste-to-energy plant is called a *mass burn facility* (**Exhibit18-1**). These facilities use solid waste directly off garbage trucks, without shredding or processing the materials. The solid waste is then fired in large furnaces to produce steam, which turns a steam turbine to generate electricity.[18]

A typical waste-to-energy plant generates about 500 to 600 kWh per ton of waste.

Exhibit 18-1



View Exhibit 18-1: Waste to Energy Plant Diagram in Text Format.

Less than a fifth of the U.S. municipal solid waste incinerators recover glass, metals and other recyclable materials and then shred the combustible materials before firing. This type of plant is called a *refuse-derived fuel* (RDF) plant.[19] Sometimes, refuse-derived fuel is prepared at one facility and then transported to another for burning.[20] The shredded waste also may be added as a fuel to boilers that burn fossil fuels.

Mass burn and RDF plants are the most common facilities in use today. A new technology called *thermal gasification*, however, changes waste into synthesis gas, a mixture of hydrogen and carbon monoxide. Contaminants are removed from this gas, which can then be burned as fuel.[21] The Dyess Air Force Base project will be a thermal gasification project.[22]

Storage

The energy or hot gas produced by waste-to-energy plants is not stored. It is used to produce energy, either to sell to an electric company or business or to produce steam for other purposes.

Availability

The nation's 87 waste-to-energy facilities are mostly located in the Northeast, but 25 states have at least one. Their generating capacity is a total of 2,720 megawatts of power, enough electricity to power all the homes in Maine, New Hampshire, Vermont, Rhode Island and most of Massachusetts. They can process 28.7 million tons of waste each year.[23] Most sites burn all types of solid waste, but some burn material separated from the main waste stream, such as tires, wood or paper.

Exhibit 18-2
U.S. Waste Disposal

	EPA Estimate 2006	BioCycle Estimate 2004
Amount of Waste Generated	251.3 million tons	388 million tons

Mode of Disposal	EPA Estimate, 2006 (Percent)	BioCycle Estimate, 2004 (Percent)
Combusted	12.5%	7.4%
In Landfills	55.0%	64.1%
Recycled or composted	32.5%	28.5%

Sources: U.S. Environmental Protection Agency and BioCycle Magazine.

According to a Columbia University survey published in *BioCycle* magazine, the U.S. generated about 388 million tons of municipal solid waste in 2004. Of this amount, about 28.5 percent was recycled and composted; about 7.4 percent was burned in waste-to-energy plants; and the majority, 64.1 percent, was put in landfills (**Exhibit 18-2**).[24]

The U.S. Environmental Protection Agency (EPA), using a different methodology, estimates that the U.S. generated 251.3 million tons of garbage in 2006. Of this amount, 81.8 million tons (32.5 percent) were recycled and composted; and 31.4 million tons (12.5 percent) were burned for energy production. The remaining 138.2 million tons (55 percent) were placed in landfills (**Exhibit 18-2**).

The waste-to-energy industry has been outpaced by the growth of recycling and composting. In 1990, recycling and composting accounted for 33.2 million tons of waste; that rose to 81.8 million tons in 2006, an increase of 146 percent. The amount of waste burned for energy recovery in 2006 (31.4 million tons) is only slightly larger than that in 1990, 29.7 million tons – a 0.3 percent average growth rate.[25]

Costs and Benefits

In 2005, an official of one of the leading U.S. companies operating municipal waste combustion facilities, American Ref-Fuel Company, testified before Congress that a new facility that can generate 60 megawatts of electricity from about 2,250 tons of trash daily would cost about $350 million. Its operating costs would be about $28 million a year.[26] This would be a very large plant; only fourteen locations in the U.S. have the capacity to combust more than 2,250 tons of trash per day.[27]

A typical waste-to-energy plant generates about 550 kWh per ton of waste. At an average price of four cents per kWh, revenues per ton of solid waste would be $20 to $30.

A Renewable Resource?

Should waste-to-energy be regarded a

renewable source of energy? Fifteen states have categorized waste-to-energy as a renewable resource in their renewable portfolio standards and some federal laws have categorized it as a renewable resource.[36] On the other hand, some federal and state tax advantages given to other renewable resources are not available to waste-to-energy facilities. In Texas, some consumer groups have opposed including waste-to-energy in Texas's renewable energy goals.[37]

Even so, waste-to-energy plants are undeniably expensive. According to the Waste-to-Energy Research and Technology Council (WTERT), capital costs to build a facility range from $110,000 to $140,000 per daily ton of capacity. Thus a plant that processes 1,000 tons of municipal solid waste per day might cost from $110 million to $140 million. It would also require a staff of about 60, and materials, supplies and the cost of ash disposal also would add to operating costs.[28]

Due in part to the high cost of their construction, no new U.S. waste-to-energy facilities have been built in the last ten years. But rising energy costs and tax and other incentives enacted in the Energy Policy Act of 2005 have prompted some existing waste-to-energy facilities to expand their capacity, and the industry is encouraging governments to build new ones. In Florida, the Lee County Solid Waste Resource Recovery Facility in Fort Meyers has begun an expansion of its facility that will expand its operations by 50 percent.[29]

The economic benefits generated by such plants include the value of the energy generated; the trash disposal fees paid by communities contracting with the waste-to-energy company; and the value of scrap collected.[30] Both the fees paid to the plant for trash disposal and fees paid for generating electricity are key to the facilities' economic success, but these are not sufficient to cover the total costs of building new facilities. Federal tax credits help to make up the difference.[31]

Environmental Impact

Burning solid waste produces nitrogen oxides and sulfur dioxide as well as trace amounts of toxic pollutants such as mercury compounds and dioxins.

The nature of the waste burned affects the composition of its emissions. If batteries or other materials containing heavy metals are burned, particularly toxic materials can be released into the air.[32] Some of these materials, such as dioxins, furans and metals, do not degrade quickly when released, and may be deposited on plants and in water. Animals and fish may absorb them, and humans may be exposed if they eat the contaminated animals or fish. Particulate matter, hydrogen chloride, carbon monoxide and nitrogen oxides also can be released into the air and absorbed into the environment.[33]

Waste-to-energy power plants use water in boilers and in cooling. When this water is discharged, its higher temperature and pollutants it contains can harm aquatic life and reduce water quality.

Scrubbers – devices that use a liquid spray to neutralize acid gases – and filters to remove particles are used to treat the emissions created when solid waste is burned. Ashes representing about 25 percent of the weight of the original combustible material are generated when waste is burned. Metals must be removed from this ash, and the ash must be tested to ensure that it meets environmental standards before it is recycled for use in roadway construction or placed in a landfill. Ash may be used as daily cover at landfills, but its disposal still represents a considerable operational cost for most waste-burning facilities.[34]

Scrubbers – devices that use a liquid spray to neutralize acid gases – and filters to remove particles are used to treat the emissions created when solid waste is burned.

In 1995, EPA ordered waste-to-energy facilities to meet maximum pollution control standards by 2000. This required the facilities to significantly reduce their emissions of dioxin, mercury, lead, cadmium, hydrochloric acid and particulates. Between that time and the present, EPA estimates that these requirements reduced emissions of dioxins and furans from waste-to-energy plants by more than 99 percent; metals by more than 93 percent; and acid gases by more than 91 percent. In 2006, EPA further tightened standards for large municipal waste burners.[35]

Noise also may be an issue with waste-to-energy plants. Trucks that bring solid waste to the facility, plant operations and fans can be sources of noise pollution.

In addition, electricity generation from waste can require some water. Estimates of water use place many biomass waste products – wood biomass, feedlot waste, municipal solid waste – in a single category. Depending on the plant type, electricity generation from waste requires withdrawals of between zero and 14,658 gallons per million Btu of heat energy produced. This is the amount of water extracted from a water source; most of the water withdrawn is returned to that source.

Water consumption refers to the portion of those withdrawals that is actually used and no longer available. Electric generation using waste consumes between zero and 150 gallons of water for each Btu of heat energy produced.

Other Risks

The expense of waste-to-energy plants poses a considerable financial risk. Assessments of their viability should include accurate projections of the amount of waste that is available to burn; the potential price for the energy produced; and potential customers for this energy.[38]

Subsidies and Taxes

A federal production tax credit of one cent per kWh is available for energy produced from municipal solid waste. Chapter 28 contains more information on biomass subsidies.

State and Federal Oversight

Federal and state pollution laws regulate waste-to-energy power plants. As mentioned previously, EPA ordered waste-to-energy facilities to reduce their emissions of dioxin, mercury, lead, cadmium, hydrochloric acid and particulates significantly.[39]

These facilities are also regulated under Texas' environmental pollution laws in the Health and Safety Code, which establishes air quality and environmental standards to protect public health and the environment.[40]

Other States and Countries

Again, most municipal solid waste combustion facilities are in the Northeastern or mid-Atlantic states.

Federal statistics for power generation from waste-to-energy plants are combined with those for power generation from landfill gas. In combination, Florida generates more energy from waste-to-energy facilities and landfill gas than any other state – an estimated 3.0 billion kWh in 2005. New York, with 2.2 billion kWh and Pennsylvania, with 2.1 billion kWh were second and third in 2005. Texas generated only 207 million kWh and most of this was from landfill gas.[41]

In 2005, there were over 430 waste-to-energy plants in Europe burning about 50 million metric tons of waste.[42] This is more than one-and-a-half times the 33.4 million tons of materials the U.S. burned in 2005.[43]

Japan incinerated 69 percent and Denmark incinerated as much as 54 percent of its solid waste for energy in 2003 (latest figure available); France and Belgium burned 32 percent each, in 2005 and 2003, respectively.[44]

Outlook for Texas

The primary advantage of waste-to-energy plants is that they consume wastes from highly populated urban areas, relieving the burden on landfills. The electricity the plants generate, however, is more costly than energy produced by coal, nuclear or hydropower plants.[45] In addition, the costs of waste-to-energy facilities are much greater than the cost of landfills – if the latter are available.[46]

The primary advantage of waste-to-energy plants is that they consume wastes from highly populated urban areas, relieving the burden on landfills.

The potential pollution problems of waste-to-energy facilities involve perceptions as well as realities. The public is likely to perceive these facilities as more polluting than other types of energy. Any new waste-to-energy plant would require zoning, air and water permits, and many communities might reject such a proposal on the basis of air pollution, noise or odors.[47]

Many urban areas in Texas already have air pollution problems, and a new waste-to-energy facility could add to them. Yet, new waste-to-energy plants must be located near large cities, because they require large amounts of waste, and the cost of transporting waste from remote locations would be prohibitive. Also, increases in recycling could affect the financial viability of waste-to-energy facilities, which depend upon dumping fees from users.

In all, the outlook for waste-to energy plants in Texas is challenging. The expense of building plants, the availability and lower costs of landfill space, air pollution problems and other issues pose considerable obstacles.

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Chapter 12

Biomass: Overview

Biomass is any plant or animal matter used to produce energy. Many plants and plant-derived materials can be used for energy production; the most common is wood. Other sources include food crops, grasses, agricultural residues, manure and methane from landfills.[1]

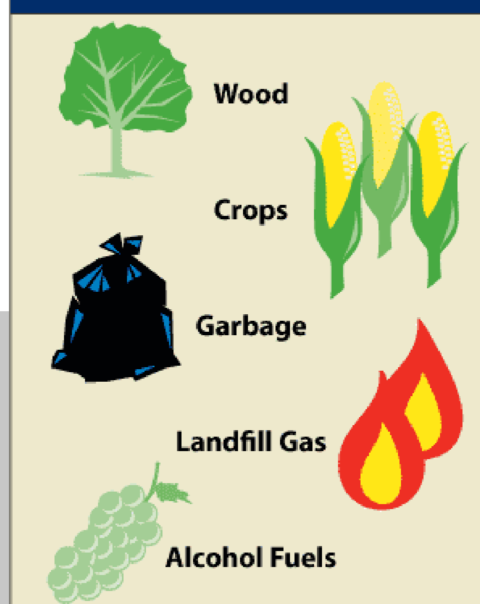
As an agricultural state, Texas has many resources for biomass energy production.

As an agricultural state, Texas has many resources for biomass energy production. Crops used to produce biomass energy – cotton, corn and some soybeans – are all grown in Texas.[2] Texas has 21 landfill gas energy projects and the potential to develop more.[3] Forests in East Texas also provide fuel for energy production. And Texas has significant quantities of manure (feedlot biomass), especially in the High Plains area where there are numerous feedlots.

While cattle manure has the most potential for power use, other forms of agricultural waste have significant possibilities, too. These include poultry litter, rice straw, peanut shells, cotton gin trash and corn stover. In fact, a recent report from the Houston Advanced Research Center estimated that Texas agricultural wastes have the potential to produce 418.9 megawatts of electricity, or enough to power over 250,000 homes, based on average Texas electric use in 2006.[4]

Exhibit 12-1

Types of Biomass

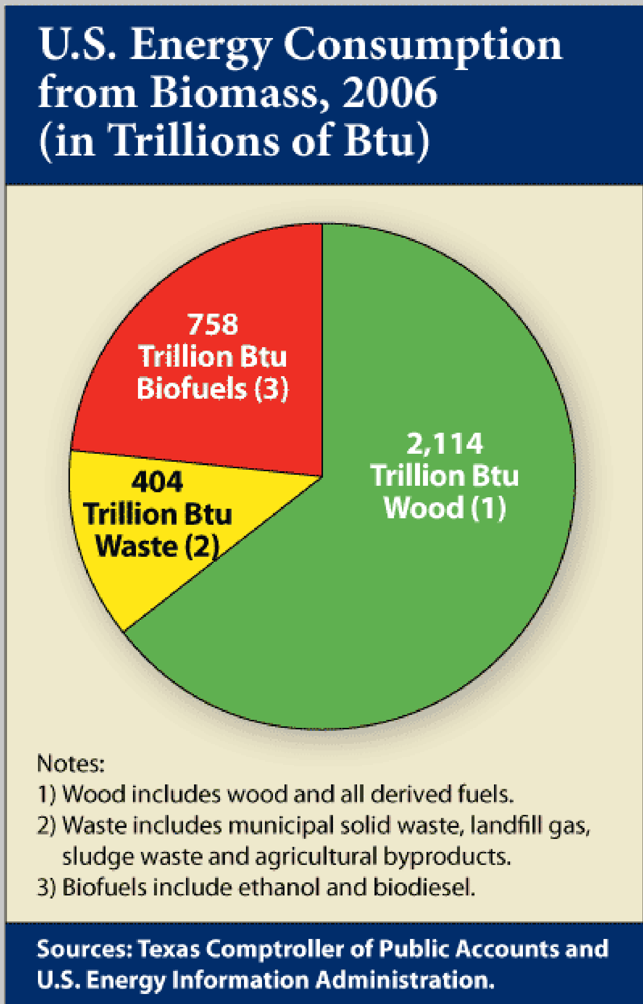


Source: U.S. Energy Information Administration.

In the U.S., the primary biomass fuels are wood, biofuels and various waste products. Biofuels include alcohols, synfuels and biodiesel, a fuel made from grain and animal fats. Waste consists of municipal solid waste, landfill gas, agricultural byproducts and other material (**Exhibit 12-1**). Most biomass energy used in the U.S. – 65 percent – comes from wood.[5] Another 23 percent of biomass energy used comes from biofuels while the remaining 12 percent comes from waste energy.

Energy generated from biomass is the nation's largest source of renewable energy, accounting for 48 percent of the total in 2006. The U.S. consumed 3,277 trillion British thermal units (Btu) of biomass energy in 2006 (**Exhibit 12-2**).[6] The next largest source of renewable energy is hydroelectric power, with 2,889 trillion Btu consumed in 2006.

EXHIBIT 12-2



View Exhibit 12-2: U.S. Energy Consumption from Biomass, in Text Format.

View Exhibit 12-1: Types of Biomass, in Text Format.

In 2005, Texas consumed 73 trillion Btu of biomass energy from wood and waste, and 2.4 trillion Btu from ethanol.[7] Currently, biomass energy accounts for less than one percent of electrical power production in Texas.[8] Texas ranked 22nd in ethanol consumption (691,000 barrels), well behind California (21,864,000 barrels), which was ranked first.[9] Two ethanol plants opened in Texas this year and others are currently under construction and will be in production by 2008. Texas is the largest producer of biodiesel in the nation.[10]

In the U.S., most renewable energy is used primarily to generate electricity, but biomass energy is an exception. In 2005, about 63 percent of biomass energy was used for heating, 26 percent for electricity generation and 11 percent as transportation fuel.[11]

Biomass energy consumption varies by sector of the economy and by state. Industry uses most of the biomass energy available in the U.S., accounting for 55 percent of total biomass energy consumption in 2006 (**Exhibit 12-3**).[12] In Texas, this pattern is more pronounced with industry accounting for 72 percent of total biomass energy consumption in 2005, the most recent data available (**Exhibit 12-4**).[13] The industrial sector, particularly the paper, chemical and food processing industries, often uses the biomass it produces in its operations to generate electricity, heat and steam that it uses on site.[14]

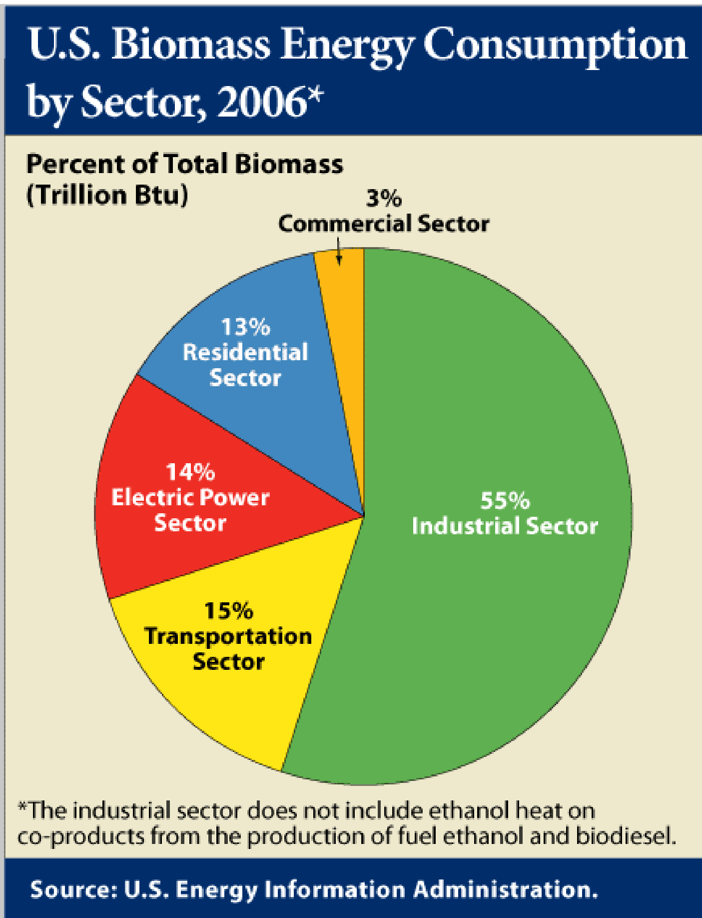
At the national level, the transportation sector is the second-largest user, accounting for another 15 percent of the nation's biomass energy consumption. In comparison, Texas' transportation sector only accounts for 3 percent of biomass energy consumption in the state. The second-largest user of biomass energy in Texas is the residential sector, which accounts for 18 percent of consumption.

The electric power sector – electric utilities – accounts for about 14 percent of the nation's biomass energy consumption, compared to just 4 percent in Texas. The commercial sector accounts for 3 percent of biomass energy consumed in the U.S and Texas.[15]

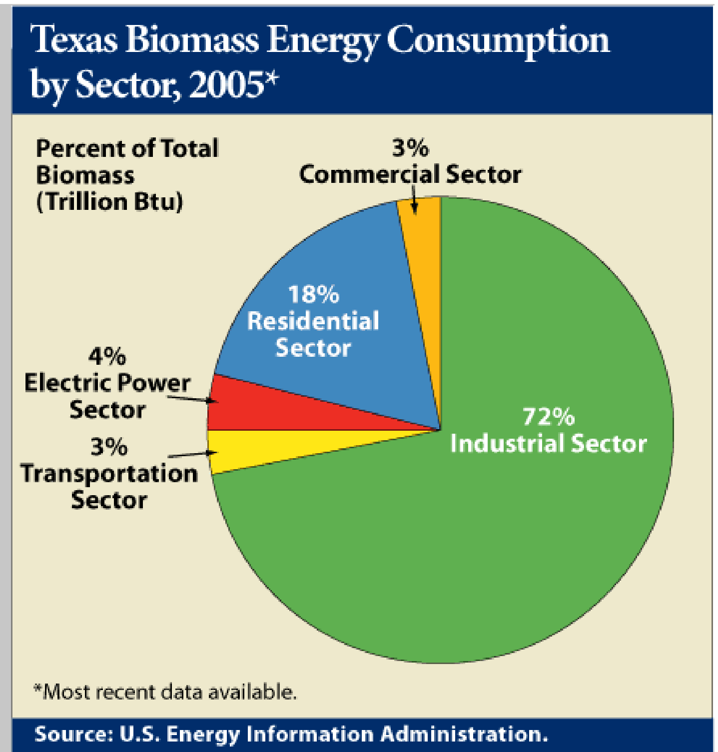
While biomass energy accounts for the majority of renewable energy production and consumption in the U.S., it is growing at a slow rate. Between 2001 and 2006, total biomass energy production and consumption both rose by an average of about 4 percent annually. Within the biomass energy category, biofuels experienced the fastest average annual growth in consumption – 24 percent – while wood and waste energy consumption expanded by an average of 1 percent and 2 percent, respectively.[16]

EXHIBIT 12-3

EXHIBIT 12-4



View Exhibit 12-3: U.S. Biomass Energy Consumption by Sector, in Table Format.



View Exhibit 12-4: U.S. Biomass Energy Consumption by Sector 2005, in Table Format.

Federal subsidies of $0.51 per gallon of ethanol and $1.00 per gallon of biodiesel have contributed to their recent dramatic production growth. For a complete discussion of subsidies, see Chapter 28.

This growth trend in consumption may continue. The Texas Agricultural Experiment Station expects the use of biofuels to grow more rapidly than other forms of biomass energy.[17] In the U.S., ethanol made from corn currently accounts for the majority of biofuel consumption in the transportation sector. In the future, however, "lignocellulosic" biofuels made from crop residue, grasses, wood products, sorghum, "energy cane" and agricultural waste are expected to supplement corn ethanol. These are commonly referred to by the shorthand term "cellulosic." Public and private funding for new research in cellulosic biofuels is increasing. Corn ethanol requires significant amounts of fertilizers, pesticides, energy and water to grow; cellulosic biofuel production promises to be much more efficient.

The amount of energy needed to produce corn ethanol is a subject of ongoing debate. Improved corn production practices and better ethanol plants, however, have led to a more efficient process. The production of cellulosic ethanol and other biofuels is expected to be significantly more energy-efficient than producing corn ethanol. At present, cellulosic ethanol is cost-prohibitive, but at least eight companies are working on technologies that may make it competitive with other fuels within five years.[18]

The Texas Agricultural Experiment Station expects the use of biofuels to grow more rapidly than other forms of biomass energy.

The rapid expansion of ethanol has resulted directly in increased corn production and higher prices. In 2006, 20.1 percent of the U.S. corn crop went to ethanol production, rising to 23.7 percent in 2007. The effect of using food crops for fuel has resulted in economic effects beyond corn, however. According to the U.S. Department of Agriculture, other field crops, livestock production costs, and food prices have been affected by corn ethanol as well. For example, higher corn prices led some soybean producers to plant more corn, reducing the amount of soybeans available. At the same time demand for soybean oil increased to make biodiesel, thereby increasing soybean prices. Also, cotton plantings were reduced by 4 million acres in 2007.

Though rising energy prices have also been a factor, the result of these trends is that animal feed prices for cattle, hogs, and poultry have risen and ultimately consumer food costs have risen, too. About 55 percent of the U.S. corn crop is used for animal feed. The effects of higher grain prices on animal feeders vary somewhat depending on the ability of some species to use a byproduct of ethanol production – distiller's grains. Beef and dairy cattle can digest this product better than hogs or poultry, for example. Ultimately, USDA projects higher farm income and retail food prices as a result of these trends and reduced profitability for livestock producers. In fact, Pilgrim's Pride, Inc., based in Pittsburg, Texas, announced that it would close a chicken processing plant in Siler City, North Carolina, and 6 of its 13 distribution centers. The company said record high prices for corn and soybean meal combined with an oversupply of chicken made it necessary to cut costs, resulting in elimination of 1,100 jobs.[19]

Higher food prices have been moderated somewhat by price competition by grocery retailers and the fact that for some food products the value of the agricultural commodity is low compared to packaging, advertising, processing, transportation and other costs.[20]

An upcoming study of the potential of all renewable resources, including biomass, mandated by the Texas Legislature, is expected to be released by the State Energy Conservation Office by early 2009.

Endnotes

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[2] U.S. Department of Agriculture, Texas Fact Sheet, www.nass.usda.gov/Statistics_by_State/Texas/index.asp. (Last visited April 21, 2008.)

[3] U.S. Environmental Protection Agency, Landfill Methane Outreach Program , "Energy Projects and Candidate Landfills," http://epa.gov/lmop/proj/index.htm. (Last visited April 21, 2008.)

[4] Houston Advanced Research Center "Combined Heat and Power Potential using Agricultural Wastes, January 2008, p.ix-x, prepared for State Energy Conservation Office, http://www.seco.cpa.state.tx.us/zzz_re/re_biomass_chp-report2008.pdf. (Last visited April 21, 2008.)

[5] U.S. Department of Energy, Energy Information Administration, Annual Energy Review 2006 (Washington, D.C., June 2007), pg. 279, http://www.eia.doe.gov/aer/pdf/aer.pdf. (Last visited April 21, 2008.)

[6] U.S. Department of Energy, Energy Information Administration, Annual Energy Review 2006 (Washington, D.C., June 2007), http://www.eia.doe.gov/emeu/aer/pdf/pages/sec10_3.pdf. (Last visited April 21, 2008.)

[7] Energy Information Administration, State Energy Data System, "Table F13a: Wood, Waste, and Ethanol Consumption Estimates by Sector, 2005. http://www.eia.doe.gov/emeu/states/sep_fuel/html/pdf/fuel_use_ww_en.pdf.

[8] E-mail communication from Linda Shirey, senior planning analyst, Electric Reliability Council of Texas, June 12, 2007.

[9] Energy Information Administration, State Energy Data System, "Table F13a: Wood, Waste, and Ethanol Consumption Estimates by Sector, 2005. http://www.eia.doe.gov/emeu/states/sep_fuel/html/pdf/fuel_use_ww_en.pdf.

[10] Texas State Energy Conservation Office, "Biodiesel Fuel," http://www.seco.cpa.state.tx.us/re_biodiesel.htm (last visited August 2007.); and EIA, Distillate Fuel Consumption Estimates by Sector, 2005, (Washington, D.C., August 2007) www.eia.doe.gov/emeu/states/sep_fuel/html/fuel_use_df.html (Last visited April 21, 2008.)

[11] Email communication from Paul Hesse, U.S. Energy Information Administration, Washington, D.C., October 17, 2007.

[12] U.S. Energy Information Administration, Annual Energy Review 2006 (Washington, D.C., June 2007), p. 279, http://www.eia.doe.gov/emeu/aer/pdf/pages/sec10_3.pdf. (Last visited April 21, 2008.)

[13] Energy Information Administration, State Energy Data System, "Table F13a: Wood, Waste, and Ethanol Consumption Estimates by Sector, 2005. http://www.eia.doe.gov/emeu/states/sep_fuel/html/pdf/fuel_use_ww_en.pdf. (Last visited April 21, 2008.)

[14] U.S. Department of Energy, Energy Information Administration, "Biomass Program: Industrial Process Heat and Steam," http://www1.eere.energy.gov/biomass/industrial_process.html. (Last visited April 21, 2008.)

[15] U.S. Energy Information Administration, Annual Energy Review 2006 (Washington, D.C., June 2007), p. 279. and Energy Information Administration, State Energy Data System, "Table F13a: Wood, Waste, and Ethanol Consumption Estimates by Sector, 2005.

[16] U.S. Energy Information Administration, Annual Energy Review 2006 (Washington, D.C., June 2007), p. 279.

[17] Interview with Bob Avant, program manager, Texas Agricultural Experiment Station, Texas A&M University System, College Station, Texas, October 26, 2007.

[18] Interview with Bob Avant.

[19] "Pilgrim's Pride Corporation to Close Chicken Processing Complex and Six Distribution Centers," (Pittsburg, Texas: March 12, 2008) News Release, www.pilgrimspride.com/ (last visited April 21, 2008.) http://phx.corporate-ir.net/phoenix.2html?c=68228&p=irol-newsarticle&id=1117942. (Last visited April 21, 2008.)

[20] Westcott, Paul, Amber Waves, U.S. Department of Agriculture, Economic Research Service, "U.S. Ethanol Expansion Driving Changes Throughout the Agricultural Sector." (Washington D.C., September 2007) Pages.1-7 http://www.ers.usda.gov/AmberWaves/September07/Features/Ethanol.htm (last visited March 3, 2008) and Leibtag, Ephraim, Amber Waves, U.S. Department of Agriculture, Economic Research Service, "Corn Prices Near Record High, But What About Food Prices?" (Washington D.C., February 2008) Pages 1-5. http://www.ers.usda.gov/AmberWaves/november07/features/biofuels.htm (Last visited April 21, 2008).

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BOYD (BY)

Correctional Institutions Division - Prison

ACA Accredited Unit Since January 1998

Unit Address and Phone Number:	200 Spur 113, Teague, Texas 75860-2007 (254) 739-5555 (**051)
Unit Location:	Four (4) miles west of Fairfield on Highway 84, Spur 113 in Freestone County
Senior Warden:	Kay Sheeley
Regional Director:	Brian Rodeen, Region II
CI Division Deputy Director:	William L. Stephens
Date Unit Established or On Line:	August 1992
Total Employees *:	325
Security Employees *:	222
Non-Security Employees *:	55
Windham Education Employees *:	20
Contract Medical and Psychiatric Employees *:	Medical = 25; Psychiatric = 3
Offender Gender:	Male
Maximum Capacity*:	1,330
Custody Levels Housed:	G1, G2, G4, Safekeeping
Approximate Acreage:	734
Agricultural Operations:	Security Horses/Dogs, Unit Garden
Manufacturing and Logistics Op.:	Stainless Steel Plant
Facility Operations:	Unit Maintenance
Additional Operations:	Windham Region II Administrative Office; Laundry Services provided to local Texas Youth Commission facility.

Medical Capabilities:	Ambulatory medical, dental and mental health services with 12 wheelchair accommodated beds. Telemedicine Services available. All services on a single level. Managed by UTMB.
Special Treatment Programs:	Physically Handicapped Offender Program (PHOP)
Educational Programs:	Literacy (Adult Basic Education/GED), Special Education, CHANGES/Pre-Release, English as a Second Language, Cognitive Intervention, Life Matters, Project RIO Career and Technology Programs: Automotive Specialization (Transmission); Construction Carpentry; Landscape Design, Construction and Maintenance
Additional Programs/Services:	Adult Education Program (upon availability), HIV Peer Education
Community Work Projects:	Services provided to city and county agencies, local organizations, the Texas Department of Transportation and Texas Parks and Wildlife.
Volunteer Initiatives:	Substance Abuse Education, Support Groups, Life Skills, Religious/Faith Based Studies and Activities

* Data as of July 31, 2009

[Return to Unit Directory]

TEA School Finance Website

▶ ARRA Title XIV State Fiscal Stabilization Fund (Posted July 31, 2009)
This is a formula grant administered by the Division of Formula Funding. For program guidelines and information click here and search for "2009-2010 ARRA Title XIV State Fiscal Stabilization Funds Grant Application"

▶ The Texas Permanent School Fund Bond Guarantee Program will re-open in early 2010 (Posted December 22, 2009)

Missed Instructional Days - Districts who have missed instructional days as a result of responding to the threat of Hurricane Ike are eligible to receive an expedited waiver for the missed instructional days. Information related to missed instructional days can be found at http://www.tea.state.tx.us/hurricane/index.html.

The new application for Missed Instructional Days for the 2008-2009 school year is posted at http://www.tea.state.tx.us/waivers/instdays/08-09AppExcInsDayMis.doc. Questions concerning the submission of this waiver should be directed to the State Waivers Division at (512) 463-9630.

▶ Hurricane Ike School District Closings

▶ School-Finance Related Correspondence to School Districts & Charter Schools

▶ School Finance Presentations

▶ House Bill 1 Salary Increase and Health Insurance

▶ Link to the School Finance Summit, Tuesday, July 29, 2008 (Audio) from the TEA Press Conferences and Briefings webpage (Posted July 30, 2008)

State Funding

A State Funding Updates Listserv has been established to provide email notification to our customers of updates to the school finance website. To subscribe to the list follow this link to http://miller.tea.state.tx.us/list, enter your name and email address, select State Funding from the drop-down list, and click on the Join a List button.

Foundation School Program

- ▶ Foundation School Program Payment System
- ▶ School District Summary of Finances and Supporting Documents
- ▶ State Funding Calendar
- ▶ 2006-2007 Near Final Settle-Up Information (Posted November 15, 2007)
- ▶ 2005-2006 Settle-Up Information (Posted April 13, 2007)
- ▶ 2004-2005 Settle-Up Information (Posted September 2, 2005)
- ▶ 2003-2004 Settle-Up Information (Posted September 3, 2004)
- ▶ 2002-2003 Settle-Up Information (Updated April 9, 2004)
- ▶ 2006-07 FINAL High School Allotment (PDF Report) | (Excel Report) (Posted May 28, 2008)
- ▶ 2008-09 ADA by District and ESC Region (PDF Report) | (Excel Report) (Posted November 12, 2009)
- ▶ 2007-08 ADA by District and ESC Region (PDF Report) | (Excel Report) (Posted November 4, 2008)
- ▶ 2006-07 ADA by District and ESC Region (Excel Version) (Posted October 19, 2007)

(District HTML Version) (Region HTML Version)

- 2005-06 ADA by District and ESC Region (Posted October 11, 2006)
- Schedule Of Monthly Foundation School Fund Payments
- Square Miles as of the Consolidations for tax year 2001
- Consolidations and Annexations for Texas Public Schools from 1983-84 to 2005-06
- Per Capita Rates 1949-50 through 2006-07
- 2006-07 Wealth Per ADA Ranking (Updated July 24, 2006)
- 2008-09 Wealth Per ADA Ranking (Updated July 10, 2008)
  (PDF Version) (Excel Version)
- 2008-09 District Payment Class
- Estimated Tuition Limit
- CPTD Tax Final (as of July, 2008): Tax year 2007 and School Funding Year 2008-2009 (Reposted June 30, 2009)
  (PDF Version) (Excel Version)
- CPTD Tax Final (as of July 2,2007): Tax Year 2006 and School Funding Year 2007-2008
  (Posted July 17, 2007)
- CPTD Tax Final: Tax Year 2005 and School Funding Year 2006-2007
- CPTD Tax Final: Tax Year 2004 and School Funding Year 2005-2006
- CPTD Tax Final: Tax Year 2003 and School Funding Year 2004-2005
- CPTD Tax Final: Tax Year 2002 and School Funding Year 2003-2004
- CPTD Tax Final: Tax Year 2001 and School Funding Year 2002-2003
- Compensatory Education Allotment - Alternative Funding Procedures (Updated June 3, 2009)
- State Funding Worksheets

Forecasting and Fiscal Analysis

- Downloadable PEIMS Financial Data (Updated August 5, 2009)
- PEIMS Financial Reports (Updated April 9, 2009)
- District Performance Summary Reports (Updated April 9, 2009)
- Expenditure Targets (Updated May 5, 2009)

Bonds

- PSF Guarantee of School Bonds
- Permanent School Fund Website
- Texas Bond Review Board's Website - School District Debt Information

Facilities Funding and Standards

- Science Laboratory Grant Program
- Existing Debt Allotment (EDA)
- 2005-2006 & 2006-2007 EDA Eligible Debt Service Report (Updated November, 2007)
- Instructional Facilities Allotment (IFA)
- Qualified School Construction Bond Program (QSCB)
- Qualified Zone Academy Bond Program (QZAB) The QZAB Documents are being updated (Posted July 30, 2009)
- New Instructional Facilities Allotment (NIFA) (Updated June 3, 2009)
- Facilities Standards and Guidelines

Chapter 41 Wealth Equalization

- Chapter 41 Overview Presentation - TASA/TASB Convention in Houston - October 2009 Posted October 22, 2009
  (PowerPoint Version) (text Version)
- Manual for Districts Subject to Wealth Equalization (Chapter 41) 2009-2010 Posted September 17, 2009
  (Word Version) (PDF Version)
- Manual for Districts Subject to Wealth Equalization (Chapter 41) 2008-2009 Posted 08/01/2008
- Chapter 41 Districts 2007-2008 Posted July 17, 2007
- Chapter 41 Districts 2008-2009 - Equalized wealth at $319,500 Posted July 29, 2008
- Chapter 41 Districts 2008-2009 - Equalized wealth at $374,200 Posted July 29, 2008
- Chapter 41 Districts 2006-2007 (**HB1, The Third Called of the 79th Legislature Session**) Posted July 21, 2006
- Potential Partner District Data 2009-2010 (PDF Report) | (Excel Report) Posted September 22, 2009
- Potential Partner District Data 2008-2009 Posted August 05, 2008
- Potential Partner District Data 2007-2008 Posted Septmeber 12, 2007
- Potential Partner District Data 2006-2007 Posted July 21, 2006
- Chapter 41 Districts and Partner Districts 1993-1994 to 2005-2006 Updated April 26, 2005
- Comptroller's Instructions for Wiring Funds
- Chapter 41 Cost of Options Report

Charter Schools

- Charter Schools Funding

School Transportation

- School Transportation Funding
- Bus Accident Reporting System (BARS)

Other School Finance Topics

- Template for Chapter 313, Economic Development Act, Estimate of Tax Credit Impact
  (PDF Version) | (Excel Version) (Posted May 13, 2009)
- Request for Additional State Aid for Ad Valorem Tax Credit (Updated April 29, 2009)
- Student Attendance Accounting Handbook (Updated October 20, 2009)
- Rider 32 Funding for 2009-10 (Posted October 30, 2009)
  (PDF Version) (Excel Version)
- Rider 34 Funding for 2008-2009 (Posted October 28, 2008)
  (PDF Version) (Excel Version)
- Rider 34 Funding for 2007-2008
- Rider 36 Disciplinary Alternative Education Program Funding
- PreK and Kindergarten Expansion Grant Program
- Administrative Cost Ratios School Years 1995-2002
- Optional Flexible Year Program (OFYP) (Updated November 24, 2009)
- Optional Flexible School Day Program (OFSDP) (Updated December 10, 2009)
- County-Level ADA Report 2008-2009 (Posted November 4, 2009)
- County-Level ADA Report 2007-2008 (Posted October 29, 2008)
- County-Level ADA Report 2006-2007 (Posted October 25, 2007)
- County-Level ADA Report 2005-2006 Posted September 26, 2006

▶ Public School Employee Health Insurance (Updated December 18, 2006)

School Financial Audits

School Financial Audits web information has moved to a new web address:

▶ School Financial Audits Web Page

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please contact our office by email: sfinance@tea.state.tx.us or by phone: (512) 463-9238.

School Finance & Fiscal Analysis
Send comments or suggestions to: sfinance@tea.state.tx.us

This page last updated December 22, 2009

TPWD District Fisheries Office

11942 FM 848
Tyler, Texas 75707
(903) 566-2161
Rick Ott, Biologist

About the Area

Local Information

- Fairfield Area Chamber of Commerce
  PO Box 912
  Fairfield, Texas 75840

Nearby State Parks:

- Fairfield Lake
  123 State Park Rd 64
  Fairfield, Texas 75840
  (903) 389-4514

More Texas Lakes

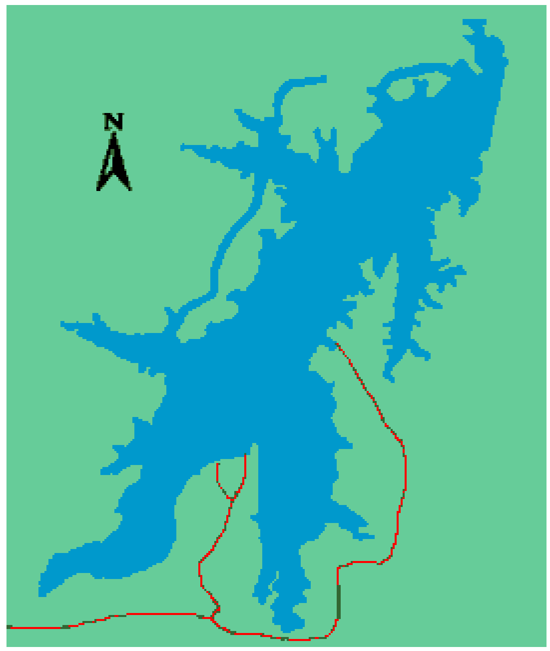
State Map
Prairies & Lakes Region
Community Fishing Lakes

Fairfield Lake

Quick Links: Fishing Regulations | Angling Opportunities | Cover & Structure | Tips & Tactics

Lake Characteristics

Location: 5 miles northeast of Fairfield off FM 488
Surface area: 2,159 acres
Maximum depth: 49 feet
Impounded: 1969



Public Access Facilities

Water Conditions

Conservation Pool Elevation: 310 ft. msl
Fluctuation: 4 feet
Normal Clarity: Moderately clear

Reservoir Controlling Authority

TXU
1601 Bryan Street
Dallas, Texas 75201
(214) 812-8699

Aquatic Vegetation

Hydrilla light along shoreline; with American lotus, common cattail, common reed and marine naiad moderate to heavy in shallow areas

Predominant Fish Species

- Largemouth bass
- Red drum
- Catfish
- Tilapia for bow fishing

Lake Records
Current Fishing Report

Stocking History

Lake Maps

None available

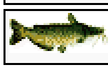
Fishing Regulations

Most fishes are currently managed under **statewide regulations**. Two **exceptions** are:

- for largemouth bass, a minimum length limit of 18 inches
- for red drum, a minimum length of 20 inches, with no maximum length and a daily bag limit of 3 fish

Angling Opportunities

Anglers should not miss the opportunity to fish for red drum in a location that does not require travel to the coast. The freshwater record (36.83 lbs) was caught in Lake Fairfield. Largemouth bass angling is excellent due to the abundant forage and year-round growing season in this heated water. Channel catfish grow rapidly and provide opportunity for high catch rates of large fish.

Species	Poor	Fair	Good	Excellent
Largemouth Bass				
Catfish				
Red Drum				

Fishing Cover/Structure

Inundated timber is abundant in the upper end of the lake and in both coves on the east side. Hydrilla forms a fringe around the reservoir out to approximately 5 feet. Pockets of native pondweed provide openings in the hydrilla and make good ambush points. The heated cove in this power plant cooling lake provides warm water even in the winter. Emergent cattails and cutgrass grow in shallow water on the shoreward side of the hydrilla.

Tips & Tactics

Largemouth bass angling starts December-February, earlier in the year than most lakes due to the heated water. Many anglers report success using jigs and pigs or lizards pitched into the openings behind cattails and cutgrass. Fishing for **catfish** can be productive by drifting live bait across the points along the area opposite of the TXU picnic area. Trolling along the west shoreline and along the dam can be productive for **red drum**.

Texas Parks and Wildlife Department, 4200 Smith School Road, Austin, TX 78744
Toll Free: (800) 792-1112, Austin: (512) 389-4800
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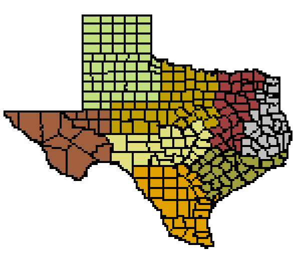
Wildlife Management in the Texas Post Oak Savannah

- Wildlife District
- Landowner Assistance
- Wildlife Management Areas
- Habitat Management
- White-tailed Deer
- Upland Game
- Waterfowl
- Pastures for Upland Birds
- Texas Wildlife

Navigate To Another Wildlife District

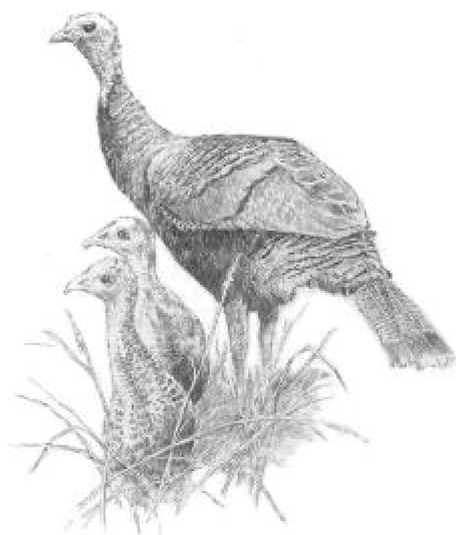
1. Trans Pecos
2. High Plains/Panhandle
3. Cross Timbers
4. Hill Country
5. Post Oak Savannah
6. Pineywoods
7. Oak Prairie
8. South Texas Plains



Texas Parks and Wildlife Department
Wildlife Division District Map

Post Oak Savannah and Blackland Prairie Wildlife Management

Historical Perspective



Wildlife Division District 5 encompasses a 31 county area extending south from the Red River to Grimes, Brazos, Burleson and Milam Counties. The district is bordered by the Cross Timbers and Prairies Ecoregion to the west, and the Pineywoods Ecoregion to the east. The western 13 counties, or portions thereof (see Texas Ecoregion Map), fall within the Blackland Prairie Ecoregion. The remaining 18 counties fall within the Post Oak Savannah Ecoregion. Average annual rainfall ranges from approximately 35 inches in the western counties to 45 inches in the eastern counties. The terrain is nearly level to gently rolling with elevations ranging from 300 ft. above mean sea level in the south to 800 ft. in the north.

There are 13 counties in the western portion of the district that are associated with the Blackland Prairie Ecoregion. Pre-settlement conditions of this region were that of a true prairie grassland community dominated by a diverse assortment perennial and annual grasses and forbs (weeds). Many early settlers who first encountered the Blackland prairie described it as a vast endless sea of grasses and wildflowers with sparsely scattered trees or mottes of oaks on uplands. Forested, or wooded areas were restricted to bottomlands along major rivers and streams, ravines, protected areas, or on certain soil types.

The remaining 18 counties within the district are part of the Post Oak

Savannah Ecoregion. As the name implies, the original plant community associated with this region was a savannah dominated by native bunch grasses and forbs with scattered clumps of trees, primarily post oaks. Forested areas were generally restricted to bottomlands along major rivers and creeks, or in areas protected from fire. Soils within the area are unique. Sands and sandy loams are predominantly found on upland sites, while clay or clay loams are typically associated with bottomlands. A dense clay pan, that is almost impervious to water, underlies all soil types within the region at depths of only a few feet.

The Blackland prairie and Post Oak Savannah landscapes were formed and maintained by two major forces: frequent fire and grazing of bison. Recurrent fires ignited either by lightning or humans (American Indian) were the major force that molded the prairie and savannah landscapes. These fires were typically very large in scale and would traverse the countryside until they reached landforms or conditions that would contain them (rivers, creek bottoms, soil change, topographical change, climatic change, or fuel change). Fire maintained these plant communities by suppressing invading woody species and stimulating growth of prairie grasses and forbs. Large herds of bison, sometimes as large as 1,000 animals, ranged the prairies and savannahs, where they would consume large quantities of grasses, trample organic matter, and then distribute seed into the disturbed soil. The grazing pressure was not continuous, however, and the large herds would move on allowing the range time to recover.

One of the earliest uses of the Blackland Prairies and Post Oak Savannah by early settlers was grazing livestock, primarily cattle and horses. Farming was also common but did not become a major use until the 1870's. During this time, with the advancement of the railroads and improved market conditions for agriculture, the prairies were plowed under and cotton replaced ranching as the principle land use. The rich soils of the Blackland Prairie were ideal for growing cotton and in a relatively short time, a majority of the desirable land was cultivated, leaving only small remnants of the original prairie intact. In the Post Oak Savannah, the land was cleared and tilled by farmers and ranchers and the use of fire was all but eliminated. The result has been a high density of mostly smaller trees with a thick understory of yaupon. Farming is still a major land use in the Blackland Prairies region today, but a large portion of the previously farmed land has been converted to pastureland (mostly monocultures of Old World bluestems, bermudagrass, or bahaiagrass) for grazing livestock. Today, the Post Oak Savannah, much like the Blackland Prairie, has been converted into vast acreages of improved pastures consisting of Bermudagrass and/or Bahaia grass.

The changes to the land that have occurred over the last 100 or so years, have dramatically altered the flora and fauna of these regions. The once diverse wildlife communities that occurred on the prairies and savannahs have been reduced dramatically, and continue to decline. With continued growth and urbanization within these regions, wildlife populations are at risk now more than ever. However, private landowners provide the key to securing the future of wildlife in these regions. With a sound, holistic approach to land management, the diversity of flora and fauna can be maintained or even enhanced over the coming decades. Aldo Leopold stated it best in his 1933 textbook Game Management. "…game can be restored by the creative use of the same tools which have heretofore destroyed it –ax, plow, cow, fire and gun." Therefore, our task as land managers is to understand the basic principals that make our system function as a whole and to apply the necessary tools in the manner in which they are needed.

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Schmidly, D. J. 2002, Texas Natural History: A Century of Change. Texas Tech University Press, Lubbock, Texas. (pp 371-374).

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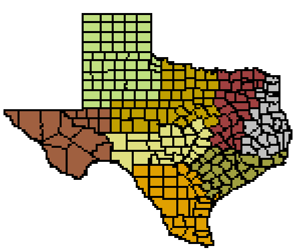

Texas Parks and Wildlife Department
Wildlife Division District Map

Oak-Prairie Wildlife Management

Historical Perspective

The Oak-Prairie wildlife district, as the name implies, spans parts of 2 different ecoregions. The northern third of the district consists of what is typically considered Post Oak Savannah, whereas the remainder of the district lies in the Coastal Prairies. This is an ecologically diverse part of Texas, and pockets of habitat more characteristic of South Texas brush country and the Pineywoods can even be found in the western and eastern reaches of the Oak-Prairie district, respectively.

The original savannahs in the northern part of the Oak-Prairie region were characterized by native grasses such as little bluestem, silver bluestem, and brownseed paspalum with scattered clumps of trees. Post oak trees dominated, but other species included blackjack oak, water oak, winged elm, hackberry, and yaupon. Fire working in concert with other factors such as drought, herbivory, and competition from grasses restricted shrub and tree growth and maintained the savannah. The natural fire frequency on level to rolling topography appears to have ranged from 5 to 10 years and on topography dissected with breaks and rivers the fire frequency may have been 20 to 30 years. Since the early 1800s, the suppression of fire, and soil disturbance and land clearing practices by farmers and ranchers have resulted in a higher density of smaller trees and more thick undergrowth of vegetation, especially yaupon. Bottomlands in the early 1800s were typically composed of large hardwoods with very little understory vegetation. Many bottomlands have now been cut over and cleared. Others have thick understories resulting from timber cutting or various soil disturbances, or are relatively open due to continuous grazing. According to written accounts from early explorers and settlers in 1800s, white-tailed deer, wild turkey, bison, black bear, squirrel, mountain lion, and red wolf were once common in the Post Oak Savannah.

The most striking change to the savannah has been the degradation or loss of the native range grasses from overgrazing and the clearing of the native range to plant monocultures of improved grasses, such as coastal Bermudagrass, for cattle. The rich diversity of grasses and weeds in the native savannah provided food and cover for many wildlife species and the conversion to "improved pastures" is responsible for the decline and even disappearance of species such as the bobwhite quail in much of the area.

The Coastal Prairie of Texas is a tallgrass prairie similar in many ways to the tallgrass prairie of the Great Plains. It is estimated that, in pre-settlement times, there were nine million acres of Coastal Prairie, of which 6.5 million acres were in Texas. Today less than one percent of the Coastal Prairie remains.

Nearly 1,000 plant species have been identified in the Costal Prairie, but no one knows how many species have followed the prairie vole and the Louisiana Indian paintbrush to extinction. The Coastal Prairie historically was home to herds of bison and pronghorn antelope, and red wolves roamed among the riverine forests that crisscrossed the area. Coastal Prairie and its adjacent marsh habitat provide immense space for waterfowl and thousands of other forms of wildlife. Even in its altered state, Coastal Prairies routinely host more red-tailed hawk, northern harriers, white ibis, and white-faced ibis than any other region in the United States. The Coastal Prairie is home to the federally endangered Attwater's prairie chicken (North America's most endangered bird) and is the exclusive wintering ground of the whooping crane.

Whereas factors such as soil type and rainfall contribute to the formation of a prairie, fire is the natural mechanism by which prairie renews itself. Fire prevents woody plants from establishing, stimulates seed germination, replenishes nutrients, and allows light to reach young leaves. Historically, prairie fires occurred in the summer as a result of lightning strikes, and the fires, along with drought and competition from herbaceous plants, prevented the establishment of woody plants to maintain a grass-dominated ecosystem.

Although much of the prairie has been converted to improved pasture for cattle grazing, the majority has been altered for growing rice, sugarcane, forage, and grain crops. Much of the Coastal Prairie that remains in Texas is because it was used for cattle production and never plowed. Many species, however, have been lost through overgrazing. Continued threats to what remains of the Coast Prairie include conversion to other kinds of agriculture and development. Most remnants are privately owned with only a small percentage preserved on government land. The prairie remnants that escape conversion or paving face overgrazing or becoming overgrown with shrubs due to the suppression of fire.

Like most of Texas, the future of the Post-oak Savannah and Coastal Prairies is in the hands of the private landowners. The good news is that landowners are becoming increasingly interested in wildlife and habitat management. More landowners earn income from other professions and depend less on the land for making a living. The major challenge is that land ownership is becoming increasingly fragmented. With each generation of our growing population, ranches and farms get smaller. Most landowners no longer own enough acreage to effectively manage for wildlife without cooperating with their neighbors. The solution is **Wildlife Management Associations** (PDF 642.7 KB) , also known as Wildlife Co-ops, which are groups of local landowners working together for their common wildlife interests. The Oak-Prairie Wildlife District leads the state in Wildlife Co-ops and the future of wildlife in this region of Texas depends largely of their success.

References:

Rideout, D. W. 1994. The post oak savannah deer herd: past, present, future. Texas Parks and Wildlife Department Publication PWD RP W7100-237B (9/94), Austin, Texas, USA.

Grafe, V., L. Allain, M. Vidrine, C. Allen, and S. Johnson. 2000. Paradise Lost? the coastal prairie of Louisiania and Texas. U.S. Fish and Wildlife Service Pamphlet, Arlington, Virginia, USA.

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Plant Guidance by Ecoregions

Ecoregion 4 – The Blackland Prairies

The fertile dark clay soils of the Blackland Prairies are some of the richest soils in the world. They are found in gently rolling to nearly level regions just west of and, in some cases, surrounded by the Post Oak Savannah of ecoregion 3. Pecan, cedar elm, various oaks and hackberry dot the landscape with some mesquite invading the southern reaches. The dominant grass of this true tall grass prairie is little bluestem, but big blue stem, Indiangrass, eastern gammagrass, switchgrass and side oats grama can also be found. Annual rainfalls of 30 to 40 inches and temperatures of 66 to 70 degrees are average for this region.

Today, this region is almost entirely under the plow, with only 5000 of the original 12 million acres remaining in true prairie condition. This region truly represents some of the rarest landscapes in Texas!

Like many prairie communities comprising the Great Plains of North America, the Blackland Prairies harbor few rare plants or animals, though the prairie itself is significantly in decline. The special and unique feature of this ecosystem today are the grasslands communities themselves.

People are often surprised to learn that trees comprised a part of the prairie ecosystems, but several tree species, including some of significant sizes, will show in this list.

Plants for the Blackland Prairies

- **Trees**
  - Pecan
  - Black Walnut
  - Sycamore
  - Eastern Cottonwood
  - Burr Oak
  - Shumard Red Oak
  - American Elm
  - Cedar Elm
  - Common Persimmon
  - Deciduous Holly

(PDF 237.1 KB)
- **Texas Wildscapes: Gardening for Wildlife Brochure** (PDF 1.7 MB)

  - Red Mulberry
  - Carolina Buckthorn
  - Huisache
  - Red Buckeye
  - Eastern Redbud
  - Mexican Plum
  - American Elderberry
  - Eastern Red Cedar
- **Shrubs**
  - American Beauty-berry
  - Buttonbush
  - Fragrant Sumac
  - Autumn Sage
- **Succulents**
  - Pale-leaf Yucca
- **Vines**
  - Cross-vine
  - Trumpet Creeper
  - Coral Honeysuckle
  - Virginia Creeper
  - May Pop
  - Prairie Rose
- **Grasses**
  - Big Bluestem
  - Sideoats grama
  - Canada Wildrye
  - Big Muhly
  - Indiangrass
  - Little Bluestem
- **Wildflowers**
  - Columbine
  - Purple Coneflower
  - Coralbean
  - Cardinal Flower
  - Turk's Cap
  - Scarlet Sage
  - Indian Paintbrush
  - Texas Bluebonnet
  - Brown-eyed Susan

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Texas Wildscapes Links:

- Certification Programs
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  - Certification as a Best of Texas Backyard Habitat
- Technical Guidance
  - Resources
  - Plant Selection and Purchase
    - Plant Guidance by Ecoregions
    - Buffalograss
    - Invasive Species That Should Be Avoided
  - Planning and Layout
    - Home Lot Development
      - Design Tips
      - San Antonio Demonstration
- Courses and Workshops
- Fostering Environmental Stewardship
- Purchase Texas Wildscapes Book
- Get FREE Interactive Wildscapes DVD
- Texas Plant Information Database (TPID)

Additional Information:

- PWD-906: Texas Wildscapes Backyard Habitat Application (PDF 170.5 KB)
- PWD-857: Best of Texas Backyard Habitat Application for Certification (PDF 195.6 KB)
- The Dangers of Invasive Species Brochure (PDF 5.2 MB)
- Best of Texas Backyard Habitats Brochure

Plant Guidance by Ecoregions

Ecoregion 2 – Gulf Coast Prairies and Marshes

A narrow band about 60 miles wide along the Texas coast from the Louisiana border to Brownsville roughly outlines the Gulf Coast Prairies and Marshes. This area is characterized by long and continual confrontations with the sea, wind and rain. These confrontations shape this place creating a tapestry of shallow bays, estuaries, salt marshes, dunes and tidal flats. Because of this proximity to the Gulf of Mexico, the plants of this region must be highly salt tolerant or halophytic.

Coastal areas are rich in wildlife. Coastal marshes harbor hundreds of thousands of wintering geese and ducks and provide critical landfall in the spring for neotropical migratory birds. Several important wildlife sanctuaries and refuges are located in this region including refuges for the endangered Attwater's Prairie-chicken and the Whooping Crane. Coastal dunes may serve as sentry roosts for north bound Peregrine Falcons in the fall. Coastal waters are often graced by willets, sanderlings, gulls, terns and Black Skimmers.

Plants for the Gulf Coast Prairies and Marshes

- **Trees**
  - Sugarberry
  - Water oak
  - Willow oak
  - Shumard red oak
  - Southern live oak
  - American elm
  - Yaupon
  - Red mulberry
  - Wax myrtle
  - Flameleaf sumac
  - Red buckeye
  - Eastern red cedar
  - Short-leaf pine
  - Loblolly pine
  - Shrubs
    American beautyberry
    Buttonbush

(PDF 237.1 KB)
- Texas Wildscapes: Gardening for Wildlife Brochure (PDF 1.7 MB)

Lantana
Dwarf Palmetto

- **Succulents**
  - Prickly-pear cactus
  - Spanish dagger
- **Vines**
  - Pipevine
  - Cross-vine
  - Trumpet creeper
  - Carolina Jessamine
  - Coral honeysuckle
  - May-pop
  - Muscadine grape
- **Grasses**
  - Big blue stem
  - Bushy bluestem
  - Inland sea-oats
  - Sugarcane plumegrass
  - Gulf cordgrass
  - Eastern gammagrass
- **Wildflowers**
  - Lance-leaf coreopsis
  - Coralbean
  - Spider lily
  - Cardinal flower
  - Turk's cap
  - Gulf Coast penstemon
  - Scarlet sage
  - Indian paintbrush
  - Beach evening primrose
  - Showy evening primrose
  - Meadow pink

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Big Lake Bottom WMA Public Use Links:

- Big Lake Bottom WMA Home
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- Maps & Directions
- Activities at a Glance
  - Hunting
  - Fishing
  - Wildlife Viewing

Wildlife Management Area Links:

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    - Equestrian
    - Fishing
    - Hiking
    - Hunting
    - Wildlife Viewing
- Wildlife Management Area Calendar
- Required Permits

Big Lake Bottom WMA

Phone: (903) 389-7080
Address:
1670 FM 488
Streetman, TX 75859

Contact: Jamie Killian

Dates Open: Open year round except closed for Special Permit Hunts.
Entire area closed: October 7-11, 23-27, and October 30 - December 15, 2006.

Description

The Big Lake Bottom WMA is owned and operated by the Texas Parks and Wildlife Department (TPWD). The 2,870-acre management area lies adjacent to the Trinity River and is located about 10 miles southwest of Palestine in Anderson County. It was purchased by TPWD to preserve the rapidly disappearing Post Oak Savannah's bottomland hardwood habitat. Currently 2,870 acres of the area are accessible and open for public use. The management area is not totally contiguous, but fragmented by private tracts of land. It is accessible from county roads at two locations.

The topography, soil types, and vegetation of the area are representative of the Post Oak Savannah river bottoms. Soils are of poorly drained clays, common on flood plains that are unprotected from flooding. Since the terrain is flat and lies within the river's flood plain, the area is often covered by shallow slow moving floodwaters. The area is normally inaccessible several times a year for extended periods due to high water or wet soil conditions. Over 90 percent of the management area is bottomland habitat of mature hardwood timber. A systematic inventory of the management area's plant community has cataloged over 450 plant species.

Principal wildlife species found on Big Lake Bottom WMA include white-tailed deer, feral hog, ducks, mourning dove, fox squirrel, gray squirrel, bobcat, raccoon, skunk, armadillo, coyote, gray fox, and many species of reptiles and migratory birds.

Please note:

- Public use of the area is allowed during daylight hours only.
- Caution should be taken since area is often muddy or under water.
- Entry is restricted to designated entry points only.

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Caddo National Grasslands WMA

Phone: (903) 328-9597
Address:
525 Madewell Rd
Paris, TX 75462

Contact: Jack Jernigan

Dates Open: Open year round.

Description

The Caddo National Grasslands WMA is administered by the US Forest Service and is managed under a cooperative agreement with Texas Parks and Wildlife.

The WMA is located in Fannin County and is divided into two units, the 13,360 acre Bois d' Arc Creek Unit and the 2,780 acre Ladonia Unit. The Bois d' Arc Creek Unit comprises six separate land tracts and the Ladonia Unit has twelve land tracts. Parks and Wildlife manages the wildlife hunting opportunities with permitted hunts. The Ladonia Unit tracts, whose boundaries are sometimes hard to find has habitat that attracts mostly doves and quail. Hunting is limited because of the boundary issues. The Bois d' Arc Creek Unit has a more diversified habitat with two lakes and four streams. This Unit is used mainly to hunt white-tailed deer, squirrels and waterfowl. Feral hogs, dove, other migratory game birds, quail, rabbit, hare, predators, furbearers, and frogs are also present. Hunting is by Annual Public Hunting Permit (APH). See the current Public Hunting Lands Map Booklet for legal species, seasons and bag limits. Trapping predators and furbearers are also permitted with a US Forest Service Permit.

Coffee Mill Lake and Lake Davy Crockett offer fishing for perch, crappie, catfish and largemouth bass with Florida largemouth bass in Lake Crockett.

Please note:

- Restroom facilities and drinking water are provided at area campgrounds.
- Boat ramps for lake fishing are provided.
- Wheel chair accessible restrooms and campgrounds are provided at Lake Crockett-East.

- For campground and equestrian information contact US Forest Service at (940) 627-5475.

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Fairfield Lake State Park

Skip Links

- History
- Activities
  - Calendar of Events
- Campsites & Other Facilities
  - Fees
  - Map of Park
    (PDF 132.6 KB)
- Natural Features
- Schedule & Directions

Check Availability / Make Reservations for Fairfield Lake S.P.
You can also make E-mail Reservations, Fax Reservations or Phone Reservations

Other Nearby T.P.W.D. Destinations:

- Fort Parker State Park
- Texas Freshwater Fisheries Center

Parks & Historic Sites - Anchor Links:

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- Park Maps
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- Special Promotions & Events
- Feature Park
- Volunteer, Concession, & Employment

Fairfield Lake State Park

123 State Park Rd 64
Fairfield TX 75840
903/389-4514

Watch video of Fairfield Lake S.P.

History: Fairfield Lake State Park is 1460 acres northeast of the City of Fairfield in Freestone County. The park was acquired in 1971 - 1972 by lease from Texas Utilities and was opened to the public in 1976.

The history of the area around Fairfield Lake State Park resembles that of much of rural eastern Texas. Long occupied by Native Americans who exploited its waterways, the land was first broken in the mid-nineteenth century and planted in cotton and corn by Anglo farmers and, about a third of the time, their African-American slaves. Following the Civil War, the crop-lien system took root. Blacks and whites alike worked in the service of the cotton crop until after World War II, when changes in American agriculture and increased employment opportunities away from the farm brought an end to the era of widespread cotton farming. Since that time, cattle ranching has prevailed throughout the region. The human population of the Brown Creek area, never large, is now widely scattered over the region. In this sparsely populated area, Texas Utilities built its dam, creating Fairfield Lake as a cooling system for its new power plant.

Activities: Activities include camping, backpacking, hiking, day use equestrian, nature study, bird watching, boating on this 2400-acre lake, water skiing, jet skiing, fishing, and lake swimming in a large, buoyed, sandy area.

Fishing: Fairfield Lake is warmed

Information
- Wi-Fi at Parks
- Texas State Parks Pass

by the TXU Big Brown power plant. Because of our warm water, people come from all over Texas to enjoy some fantastic winter fishing opportunities. From November through February, we have tournaments every weekend. Fishing Clubs from the Dallas/Fort Worth, Houston, Waco, Austin, and Tyler areas host tournaments here. Why drive all the way to the Texas Gulf Coast to enjoy fishing for Red Drum! What makes Fairfield different then most lakes is that, because of the warm winter temperatures, it is stocked with Red Drum (aka Red Fish). The state record for Inland Red Drum was taken here at Fairfield Lake. (44 inches, 36.83 lbs.)

- Watch video of Fairfield Lake State Park.
- Check the Calendar for events and access restrictions scheduled within the next 3 months.
- Detailed fishing & lake information for Fairfield Lake.
- More Information on outdoor activities from the Experience Texas page.

Area Attractions: Nearby points of interest include Texas State Railroad, Fort Parker State Park; Old Fort Parker (operated by the City of Groesbeck), and Confederate Reunion Grounds State Historic Site; the Cities of Rusk, Palestine, and Fairfield (where the Freestone County Museum in the century-old jail is located). While you are in the area, visit the Texas Freshwater Fisheries Center in Athens a unique TPWD facility showcasing aquatic life and sport fishing in Texas.

Campsites & Other Facilities: There are campsites with water (most on the lakefront); campsites with water and electricity; a hike-in primitive camping area (at the end of a 6-mile, round-trip hiking trail); picnicking; an overflow camping area; restrooms with and without showers; a lighted fishing pier; a fish-cleaning shelter; a fish-cleaning table; boat ramps; a trailer dump station; playgrounds; a group dining hall for day-use only; and an amphitheater.

A six-mile trail has connected an older 9-mile trail to provide a continuous 15 miles of trailways that provide multi-use (hiking, mountain biking, and equestrian) access from one end of the park to the other. Much of the trail is adjacent to the 2400-acre Fairfield Lake. There is also a 2-mile nature trail and 1 mile of bird watching trail.

Firewood, ice and park-related merchandise can be purchased at the State Park Store. There is an honor box to collect park use fees after office hours.

- Fees
- Map of Park (PDF 132.6 KB).

Check availability/make reservations for Fairfield Lake S.P.
You can also make e-mail reservations, fax reservations or phone reservations.

Natural Features: Surrounding woods are

oak, hickory, cedar, elm, dogwood, and
redbud, which offer sanctuary for many species of birds, and mark the transition zone between the pine forests to the east and the prairie grasslands to the north and west. Wildlife found in the park include osprey (year-round), bald eagles (November through February), white-tailed deer, raccoons, foxes, beavers, squirrels, and armadillos. Popular catches include catfish, bass, carp, freshwater redfish, and other varieties.

More information on the wildlife mentioned here:

- Texas Wildlife Factsheets.

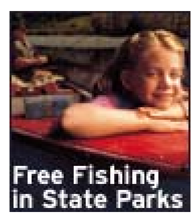
Elevation: 461 ft.
Weather: July average high is 95; January average low is 35; April and May are wettest months; first/last freeze: November 29/March 11.

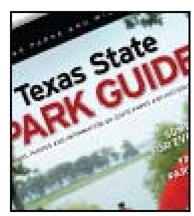
- National Weather Service forecast for this area.

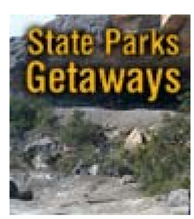
Schedule: Open: 7 days a week year-round, except for Public Hunts. Check the Calendar for events and access restrictions scheduled within the next 3 months. Busy season: March through November.

Directions: The park is 6 miles northeast of Fairfield off FM 2570 on FM 3285 adjacent to Fairfield Lake. 90 miles south of the Dallas/ Fort Worth area, 150 miles north of the Houston area, and 60 miles east of Waco. The park is located just a few miles from Interstate 45, northeast of the city of Fairfield, Texas.

Current conditions including, fire bans & water levels, can vary from day to day. For more details, contact the park.







More Promotions.

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Gus Engeling WMA Public Use Links:

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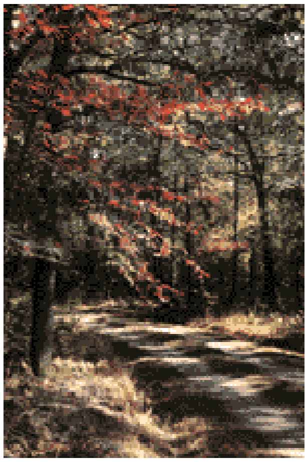
Gus Engeling WMA (GEWMA)

Phone: (903) 928-2251
Address:
16149 North US Hwy 287
Tennessee Colony, TX 75861

Contact: Wes Littrell

Dates Open: Open year round, **except area closed during special hunts.**

Description



Gus Engeling Wildlife Management Area (GEWMA) is located in northwest Anderson County, 21 miles northwest of Palestine. This 10,958 acre area was purchased from 1950 to 1960 under the Pittman-Robertson Act using Federal Aid in Wildlife Restoration Program funds. The (GEWMA)'s primary purpose is to function as a wildlife management, research and demonstration area for the Post Oak Savannah Ecoregion. The area is comprised of 2,000 acres of hardwood bottomland floodplain and almost 500 acres of natural watercourse, 350 acres of wetlands: marshes and swamps and nearly 300 acres of sphagnum moss bogs. The (GEWMA) is an island of Post Oak Savannah surrounded by coastal bermuda grass pastures, harvested timberlands, and fragmented wildlife habitat. It's rolling sandy hills dominated by post oak uplands, bottomland hardwood forests, natural springs, pitcher plant bogs, sloughs, marshes, and relict pine communities contain a rich variety of wildlife. Sound wildlife management tools like prescribed burning grazing, brush control and hunting are used to demonstrate the results of proven practices to resource managers, landowners, and other interested groups or individuals.

History:

Historically, the upland sites of the Post Oak Savannah were open and dominated by waist-high grasses and large scattered trees. In addition, early observers reported large oak "motts" or islands of continuous hardwoods scattered throughout the grassland prairie. Bottomlands were dominated by mature massive oaks that prefer deep, rich, moist soils. Both uplands and bottomlands supported an abundance of wildlife before man's intervention. By the mid-1800's European settlement produced dramatic changes in East Texas. Timber operations, prevention of wildfires, damming of streams and rivers, and clearing of land for pasture and crops changed the land. The first barbed wire fence was constructed in 1888. Within two years most of the land had been fenced and was severely overgrazed by hogs and cattle. Hardwoods in the bottomlands were logged during these years. The trees which made the best homes for wildlife, such as large and vigorous white oaks, walnuts, and hickories, were the first taken. Although not marketable, many good wildlife trees, such as young hardwoods and old pines, were removed and replaced by loblolly pines for timber. These loblolly pines invaded the flood free bottoms below dams, reducing the numbers of hickories and oaks. Cavity dwelling wildlife, such as wood ducks, woodpeckers, raccoons, squirrels, and many other birds and mammals, found fewer homes after the loggers passed. Most cultivated land was planted in cotton at this time, with some small farms growing row crops.

The turn of the century marked the beginning of the livestock industry in this area. Most of the land was severely overgrazed by hogs and cattle for the first half of the century. In the mid-1900's, there was an increase in livestock production resulting in the clearing of large tracts of hardwoods for pasture. Livestock production continues to be the principal land use in this part of Texas. Although still called the Post Oak Savannah, this part of East Texas is now quite different from the countryside seen by the first settlers.

Most of the land comprising the GEWMA was purchased by the then Texas Game, Fish and Oyster Commission between 1950 and 1960. Much of this land was purchased from Milze L. Derden, hence the original name Derden Wildlife Management Area. The GEWMA was purchased under the Pittman-Robertson Act as a wildlife research and demonstration area for the Post Oak Savannah Ecoregion where trained personnel could study wildlife management practices.

The area was renamed in 1952 after Gus A. Engeling, the first biologist assigned to the area, was shot and killed by a poacher on December 13, 1951.

The GEWMA has not suffered from man's presence as much as most of the Post Oak Savannah. Although the land was used for livestock for many years, it was not extensively cleared. Mature bottomland forests still dominate Catfish Creek. Five hundred acres of post oak uplands have nearly been returned to its original Post Oak Savannah state through 35 years of prescribed burning.

Goals:

The initial goal and intended purpose of the Gus Engeling WMA was to serve as a wildlife research and demonstration area where trained biologists could study and evaluate wildlife and habitat management practices. Around 1990 the majority of staff duties shifted from research to public use activities and development. Future activities will return to research and demonstration designed to benefit people interested in wildlife management in the Post Oak Savannah.

In 1989, the following goals were adopted by the Wildlife Division and are used as guidelines for preparing WMA management plans. The goals are listed in priority order.

- To develop and manage wildlife habitats and populations of indigenous wildlife species.
- To provide a site where research of wildlife populations and habitat can be conducted under controlled conditions.
- To provide areas to demonstrate habitat development and wildlife management practices to landowners and other interested groups.
- To provide natural environments for use by educational groups, naturalists, and other professional biological investigators.
- To protect populations of endangered or threatened migratory wildlife, plant species, related habitats, unique natural sites and relic vegetation communities.
- To provide public hunting and appreciative use of wildlife in a manner compatible with the resource.

Natural Resources - Flora/Fauna:

The GEWMA is representative of the Post Oak Savannah Ecoregion which encompasses approximately 13,300 square miles of Texas reaching from Red River County in the northeast to Guadalupe County in the south. Upland soils are generally light-colored, deep, rapidly permeable sands and sandy loams. Bottomland soils are mostly mixed alluvial clays and clay loams, gray brown in color and moderately permeable. Topography is gently rolling to hilly with a well-defined drainage system that empties into Catfish Creek which is a tributary of the Trinity River. Eight miles of Catfish Creek have been designated as a "Natural National Landmark" by the US Department of the Interior. The drainage system encompasses approximately 2,000 acres of bottomland. Average annual rainfall is approximately 40 inches. Generally, rainfall is fairly evenly distributed throughout the year with less occurring during July and August.

Vegetation present in the uplands includes a dense overstory of oak, hickory, elm, and gum with a shade tolerant understory of flowering dogwood, American beautyberry, greenbriar, farkleberry, yaupon, possumhaw, dewberry, and hawthorn. Common grasses include little bluestem, broomsedge bluestem, slender Indiangrass, purpletop, beaked panicum, and spike uniola. Some dominant forbs include tickclover, wildbean, goldenrod, and doveweed. Oak trees, mostly water and willow oak, are the dominant tree species in the bottomlands. Common wetland plants include yellow lotus, common duckweed, sedges, rushes, pondweed, giant cutgrass, and plumegrass. Depending on rainfall and weather conditions, spring displays of flowering dogwood and wildflowers can be spectacular.

Between 1860 and 1920, year-round hunting with no bag limits greatly reduced the deer and turkey number. From 1948 to 1950, 280 white-tailed deer, 128 Rio Grande turkey, and 13 beavers were released on the area. The deer population steadily increased resulting in the opening of a deer season in 1955. This population remains healthy and provides a major source of recreation. Beavers are now abundant and have created many acres of wetlands on the GEWMA and surrounding lands. Wild turkeys did not prosper; so several more releases were made. The result was a small, unstable population of hybrids between pen-raised Eastern gobblers and Rio Grande hens. More recently, releases were made in 1988, 1995 and 1996. The first Eastern wild turkey hunt was held in 2003.

The GEWMA has a rich variety of wildlife. Currently 37 mammals, 156 birds, 54 reptiles and amphibians, 57 fishes and 900 plant species have been documented. There's no guarantee, but the observant visitor may see white-tailed deer, Eastern wild turkey, gray squirrels, fox squirrels, raccoons, beavers, wood ducks, or pileated woodpeckers just to name a few.

Cultural Resources:

The stewardship role of TPWD staff regarding archeological resources and historic resources is defined in the Antiquities Code of Texas (Title 9, Chapter 191 of the Texas Natural Resources Code of 1977), which calls for the location and protection of all archeological sites owned by the State of Texas. Any violation of the terms of the Antiquities Code is a criminal act, punishable by a fine and/or jail term.

Research Activities:

One of the principle goals of the Gus Engeling Wildlife Management Area is to provide a site where research of wildlife populations and habitat may be conducted under controlled conditions. Through such studies biologists hope to gain a better understanding of the interrelationships between native wildlife species, domestic livestock, and habitat resources. This will enable biologists to make recommendations for a sound multiple-use management program tailored to the Post Oak Savannah region of Texas. As of 1997, 35 approved research projects have been conducted on the Engeling WMA involving such topics as:

- White-tailed deer aging techniques
- Factors affecting white-tailed deer fawn survival
- Comparisons of feeding habits between white-tailed deer and cattle
- Site-specific competition between feral hogs and white-tailed deer
- Primitive weapon hunting techniques
- Effects of selective clearing on wildlife habitat
- Quail population responses to habitat manipulation
- Controlled burning to improve woodland habitat for wildlife

Current projects are investigating the usefulness of feral hog control measures in aiding nesting success of Eastern turkeys and conducting a complete vegetation analysis and Geographical Information System (GIS) mapping of the entire Area.

Recreational Opportunities :

Anglers and hunters interested in waterfowl and small game need only possess an

APH Permit and valid fishing or hunting license to gain access on designated days during the appropriate season. Deer hunters, both archery and gun, are randomly selected during the Special Permit drawing to avoid over harvesting of the resource.

Visitors may enjoy nature viewing, bird watching, photography, hiking, camping and the general beauty of nature. Botanists and wildflower enthusiasts may revel in the dazzling spring and fall displays. The GEWMA also serves as an outdoor laboratory for local colleges, universities, elementary, and secondary schools.

A self-guided auto tour takes a visitor through 10 stops which address wildlife, habitat and management techniques. In addition, the Beaver Pond Nature Trail and Dogwood Nature trail offer visitors the chance to personally experience the lush green mysteries of East Texas. But be warned, all four varieties of venomous snakes occur in this area - so please watch your step. Visitors seventeen years of age and older must posses either an **Annual Public Hunting (APH) Permit** or **Limited Public Use (LPU) Permit** to utilize the WMA (no permit required for the driving tour and nature trails). These permits are available at all license sale locations in Texas or by calling **1-800 TXLIC4U (895-4248)**. Permits are not for sale at the WMA. Refer to Outdoor Recreational Opportunities on WMAs for additional information about opportunities on the Gus Engeling WMA.

Please note:

- **All users must perform on-site daily registration.**
- Bring your own drinking water.
- The wildlife observation blind and the restrooms are wheelchair accessible.
- Walking in the bog area is prohibited.
- Insecticide and sunscreen are advised.
- Alligators inhabit some areas and should be considered dangerous.

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Richland Creek WMA

Phone: (903) 389-7080
Address:
1670 FM 488
Streetman, TX 75859

Contact: Matthew Symmank

Dates Open: Open year round, except closed for Special Permit hunts.

Description

The Richland Creek WMA was named for Richland Creek, a tributary to the Trinity River, which flowed through the property prior to the construction of Richland-Chambers reservoir. Richland Creek Wildlife Management Area was created to compensate for habitat losses associated with the construction of Richland-Chambers Reservoir. The Area is owned and managed by Texas Parks and Wildlife Department. The mission of RCWMA is to develop and manage populations of indigenous and migratory wildlife species and their habitats and to provide quality consumptive and non-consumptive public-use in a manner that is not detrimental to the resource.

Richland Creek Wildlife Management Area is located in an ecotone separating the Post Oak Savannah and Blackland Prairie ecological regions and the Area lies almost entirely within the Trinity River flood plane. The Area is subject to periodic and prolonged flooding. Average annual rainfall is 40 inches. Soils consist primarily of Trinity and Kaufman clays. These bottomland soils are highly productive and support a wide array of bottomland and wetland dependant wildlife and vegetation communities.

Vast bottomland hardwood forest communities characterized by cedar elm, sugarberry, and green ash dominate the area. Honey locust, boxelder, and black willow are also common. Pockets of bur oak, shumard oak, overcup oak, water oak, willow oak, and native pecan also occur. The understory is dominated by hawthorn, cat briar, poison ivy, and rattan with shade tolerant grasses and forbs comprising the herbaceous layer. Large non-forested areas also occur and are characterized by diverse herbaceous communities.

The vast bottomland hardwood forests serve as nesting and brood rearing habitat for many species of neotropical birds. The Area has numerous marshes and sloughs, which provide habitat for migrating and wintering waterfowl, wading birds and shore birds, as well as diverse aquatic life.

Please note:

- Bring your own drinking water.
- Restrooms unavailable.
- Flooding may occur during heavy rains, so be prepared to move to higher ground.
- ATV's allowed only during special permit hunts.
- Each permit holder may possess one dog while hunting waterfowl, squirrels or rabbits. Companion dogs must be leashed or confined within designated campsites.

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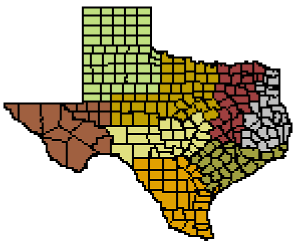
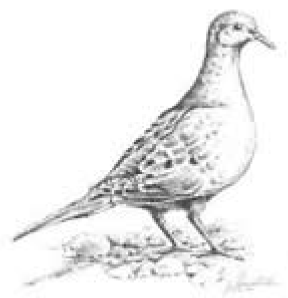


Texas Parks and Wildlife Department
Wildlife Division District Map

Oak-Prairie Wildlife Management

Upland Game



Changing land use practices over the years has reduced upland game species habitat in the Oak-Prairie Regulatory District. Historically, many of the northern counties in the district had a lot of small farms. These farms provided excellent habitat for doves and quail. Today the small-scale farmer is almost extinct. The farms that remain are usually large-scale operations. Modern farming practices are quite different from the day of the small farm operation. These large farms use modern techniques that are not beneficial to wildlife species.

Another major change that has occurred over large areas of the district has been the conversion of native pastures to improved grasses to enhance cattle production. As a result, native pastures have become rare in many areas. Broadleaf plants or forbs (weeds) are extremely important to wildlife species, particularly quail and doves. Forbs are usually abundant on native pastures, but low in numbers on improved grasslands or native pastures that are constantly overgrazed by cattle.

The absence of small farms and the conversion to improved pastures has greatly reduced the quail population. However, there are still areas that have fairly good quail numbers in the southwestern part of the district, where there are still large ranches that have not converted their native pastures to improved grasslands and that do not overstock their pastures. The native clump grasses (little bluestem, big bluestem, Indian grass), when properly managed, provide the best quail nesting habitat and will support the high populations.

Dove hunting is still quite popular in many parts of the Oak-Prairie region. However, dove numbers are directly related to food supply. Planting food plots to attract doves is becoming more popular in the area. Good feeding areas provided by native weeds such as Croton (dove weed), sunflowers, etc. often result in a limit of birds for the dove hunter. During some years the winter dove season also provides a lot of shooting. However, just as in the fall season, there must be a good food supply available to attract and hold the birds in an area.

There are two species of turkeys in the Oak-Prairie wildlife district. The eastern tier of counties has been stocked with the eastern turkey. Reproduction has been quite limited in this population. However, it is too early to tell if the stocking will be a success or failure. The Rio Grande turkey is found in many of the counties of the district. Although widespread, most counties do not support a large number of birds. Many areas do not provide adequate turkey habitat. The birds are usually found along the major creek and river drainages. Most counties have only a spring turkey season, although several have a fall season as well.

Management

- **Habitat Management**
- **Learn About Turkey** (**PDF** 350.3 KB)
- **Rio Grande Turkey Management** (**PDF** 1.9 MB)
- **Bobwhite Quail in Texas** (**PDF** 412.2 KB)

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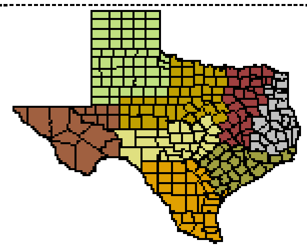
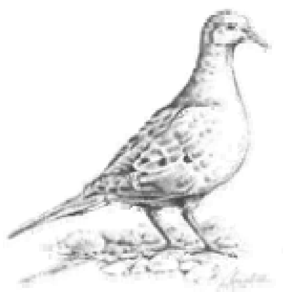


Texas Parks and Wildlife Department Wildlife Division District Map

Upland Game of the post Oak Savannah and Blackland Prairie



Upland game generally refers to wild game species (species with a regulated hunting season) whose habitat is primarily found on upland sites (high ground). In the Post Oak Savannah and Blackland Prairie ecological regions of Texas, the most abundant upland game species is the mourning dove (Zenaida macroura). Although not as numerous as mourning dove, wild turkey, (Meleagris gallipavo) and bobwhite quail (Colinus virginianus) are also found in localized areas where adequate habitat and space exists.

To learn more about the upland game species of the Post Oak Savannah and Blackland Prairie, their habitat and management, please note the additional links provided on the sidebar.

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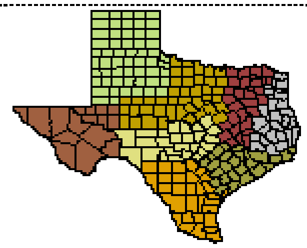
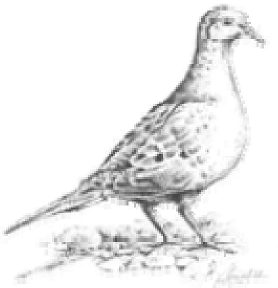


Texas Parks and Wildlife Department
Wildlife Division District Map

Mourning Dove in the Post Oak Savannah and Blackland Prairie

Mourning Dove



The mourning dove is common throughout the Post Oak Savannah and Blackland Prairie regions, but populations are generally highest in the western counties where more open habitat exists.

As with all wildlife, dove habitat must provide adequate food, cover, and water. Since doves are capable of traveling long distances to fulfill all of their habitat needs, individual habitat components (food, cover, and water) do not have to be located in one centralized area to be of benefit. However, doves can often be attracted to areas where all habitat components are present in a localized area.

Food

The primary diet of mourning doves is seeds produced from native and introduced plants. Plants common to the Post Oak Savannah and Blackland Prairie regions that are important to mourning dove include: sunflower, croton (goat weed or dove weed), ragweed and partridge pea. Introduced plants important to dove, planted as part of agricultural operations, include: grain sorghum (milo), forage sorghum (hay-grazer), corn, wheat and Johnsongrass.

Simply disturbing the soil after the first freeze will encourage native annual plants that are important food source for doves. Disking, plowing and prescribed burning are all practices that can be used to promote important annual native seed producing plants. In addition to promoting seed producing plants, these practices also expose some bare ground making it easier for dove to forage.

Agricultural fields that grow grain sorghum, wheat, and corn are important food sources for doves. These fields can be manipulated by harvesting strips at different times, to spread out the availability of seed over a longer period. Also, leaving stubble until the following growing season will provide some cover that will make the fields more desirable to doves.

Food plots can also be planted to attract and provide food for doves. Planting desirable seed producing plants, such as sunflowers, milo and dove prozo millet in May will often produce productive dove fields. However, plots planted with native sunflower will germinate best when planted in fall. Food plots should be at least 25 acres in size and adequately fenced off from cattle. Shredding strips through food plots, beginning in mid August, will improve access to seed for doves and make it easier to locate harvested birds.

Cover

Unlike other game species, such as bobwhite quail, wild turkey or white-tailed deer, doves do not require much cover to meet their habitat needs. In fact, doves prefer fairly open habitat with only scattered trees for perching and nesting. Therefore, providing a savannah type of habitat with plenty of seed producing plants and scattered trees 10 to 30 feet tall will provide dove with all of the cover they require.

Water

The Post Oak Savannah and Blackland Prairie regions contain numerous small stock ponds scattered throughout rural areas. Mourning doves are swift fliers, capable of covering long distances in a relatively short period of time and for this reason, water is generally not considered a limiting factor of dove habitat in these regions. However, existing stock ponds can be manipulated to make them more favorable for usage by doves. Doves will generally water twice daily and prefer watering sites that do not contain tall, concealing vegetation. Also, doves prefer several feet of fairly level bare soil up to the water edge for a landing area.

Providing a habitat with all of the daily requirements (food, cover and water) will attract more doves to your hunting area and also improve reproduction for this popular Texas upland game bird.

For assistance in developing a habitat management plan for your property, please contact your local Texas Parks and Wildlife Biologist.

To locate the Texas Parks and Wildlife biologist in your area .

To learn more about the upland game species of the Post Oak Savannah and Blackland Prairie, their habitat and management, click on the appropriate link located on the sidebar.

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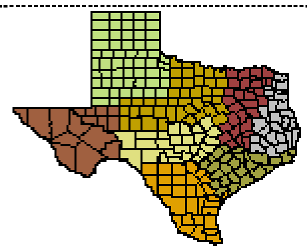
- Landowner Assistance
- Wildlife Management Areas
- Habitat Management
- White-tailed Deer
- Upland Game
- Waterfowl
- Pastures for Upland Birds
- Texas Wildlife

Upland Game in the Post Oak Savannah and Blackland Prairie

Bobwhite Quail
Mourning Dove
Wild Turkey

Navigate To Another Wildlife District



Texas Parks and Wildlife Department
Wildlife Division District Map

Post Oak Savannah and Blackland Prairie Wildlife Management

Wild Turkey

There are two sub-species of wild turkey that occur in the Post Oak Savannah and Blackland Prairie regions:

1. Eastern Wild Turkey (Meliagris gallopavo sylvestris), and
2. Rio Grande Wild Turkey (Meleagris gallopavo intermedia).

Beginning in 1987, Eastern wild turkeys were re-stocked into most counties of the Post Oak Savannah where enough suitable habitats were present. Rio Grande wild turkey have been re-stocked throughout Texas where average annual precipitation is less that 35 inches. Re-stocking efforts have since concluded and populations of Eastern and Rio Grande wild turkeys have been re-established in several counties in the Post Oak Savannah and Blackland Prairie regions. Eastern wild turkeys are currently present in the northern and eastern counties of the Post Oak Savannah. Rio Grande wild turkeys are present in counties along the western edge of the Blackland Prairie region and southern counties of the Post Oak Savannah region.

As with all wildlife, habitat is the single most important factor in maintaining healthy and viable populations of wild turkey in the Post Oak Savannah and Blackland Prairie regions. The wild turkeys are members of the same family as the bobwhite quail (Family Galliformes), therefore, many of the same habitat factors that limit bobwhite populations also limit wild turkey populations, especially those concerning nesting and brood rearing habitat.

Wild turkeys are a resident non-migratory species, with a home range that averages about 2,000 to 5,000 acres and changes seasonally. During spring and summer, which is the nesting and brood rearing period, turkeys tend to be widely dispersed in habitats that contain scattered thickets of low growing brush, patches of residual herbaceous vegetation and a diverse grass/forb plant community that produces abundant seed and insects. During fall and winter, turkeys tend to congregate into large flocks that have ranges centered around riparian areas (flood plains of major creeks and rivers) containing large stands of mature hardwood trees.

Habitat management for wild turkeys should be concerned with the availability and distribution of food, cover, and water. The following sections will outline the basic habitat components for wild turkeys and the management practices used to establish or maintain them.

Food

Wild turkeys are opportunistic feeders, meaning they will generally eat what is available as they encounter it. The diet of the wild turkey is also omnivorous, meaning that it consist of a wide variety of plant and animal matter. However, the principal food items of the wild turkeys include mast (acorns and nuts), fruits, seeds, green plant matter, agricultural crops and animal matter (insects). Some important plants for wild turkeys include:

1. Oaks (acorns),
2. Hickories and pecan (nuts),
3. Partridge pea (seed),
4. Croton (seed),
5. Mesquite (seed),
6. Dogwood (fruit),
7. Sumac (fruit),
8. American beauty-berry (fruit),
9. Grape (fruit),
10. Blackberry and dewberry (fruit),
11. Hackberry (fruit),
12. Cedar elm (fruit),
13. Paspalum grasses (seed), and
14. Panicum grasses (seed).

Production of important seed and mast producing plants can be encouraged by implementing practices such as prescribed burning, fallow disking, rotational grazing, food plots, and timber management.

Cover

Cover requirements for wild turkey can be broken down into three distinct categories:

1. Nesting Cover
2. Brood rearing cover, and
3. Roosting Cover

Nesting cover for wild turkey typically contain a dense herbaceous layer and some shrubs, or brush, cover near ground level. Turkey nests are generally located close to openings near some type of structure. Nesting cover for turkeys can be promoted by excluding areas along woodland edges from mowing or grazing and protecting areas with existing brush or dense herbaceous vegetation from disturbance.

Brood rearing cover, commonly referred to as bugging areas, is the most important component of the wild turkey's habitat and is typified by areas having a diverse mixture of grasses and forbs that produce abundant insects. As with quail chicks, turkey poults require a high protein diet of insects and spiders during the early stages of growth. Additionally, good brood rearing habitat needs to be tall enough to conceal the poults from predators, yet short enough for the hen to see over (about 3 feet tall). Brood rearing habitat can be maintained by rotating livestock on native pastures, prescribed burning (3-year rotation), and fallow disking.

Wild turkeys prefer to roost in large, mature hardwood or coniferous trees with large horizontal limbs. Therefore, care should be taken to protect these trees from land clearing operations, especially along creeks, drainage areas, and wetlands.

Water

Turkeys, like all other terrestrial animals, require water for survival. Wild turkeys are able to get water from green plant material, fruits, insects, dew and free water from puddles, ponds, creeks and rivers. In the Post Oak Savannah and Blackland Prairie, water is generally not considered a limiting factor in habitat, except during extreme periods of drought.

Summary

For the most part, wild turkey restoration efforts in certain portions of the Post Oak Savannah and Blackland Prairies regions have been a success. However, with the imminent threat of land fragmentation, the future of wild turkeys in these regions is not certain. To perpetuate the wild turkey in these regions, land managers must be able to recognize the habitat components essential to these birds, and implement the land management practices necessary in maintaining a healthy habitat. Also, in dealing with the issues of land fragmentation, landowners will need to work together more than ever. Therefore, landowner wildlife management associations (co-op's) will be an important part of wildlife habitat management as we progress through the 21st century.

For assistance in developing a habitat management plan for your property, please contact your local Texas Parks and Wildlife Biologist.

To locate the wildlife biologist in your area **CLICK HERE**.

To learn more about the upland game species of the Post Oak Savannah and Blackland Prairie, their habitat and

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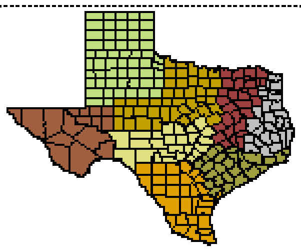

Texas Parks and Wildlife Department Wildlife Division District Map

Bobwhite Quail in the Post Oak Savannah and Blackland Prairie

Bobwhite Quail

Historically, bobwhite quail were common throughout the Blackland Prairie and Post Oak Savannah regions of Texas. However, over the last 3 to 4 decades, quail numbers have declined dramatically within these regions and have even disappeared in some localities. The loss of quail is not restricted to these two regions, but is occurring across the state and even throughout the birds' natural range in other states. Statewide, data collected from the U. S. Fish and Wildlife Service's annual Breeding Bird Survey indicate that the bobwhite population has declined at an average rate of 5 % per year from 1980 to 2000. Nationally, the Breeding Bird Survey data indicates that numbers have declined at an average rate of 4 % per year from 1982 to 1999. This decline is staggering, and in some regions of Texas, it is expected that the bobwhite could vanish totally within the next two decades unless changes are made to turn the decline around.

Although there are many factors that have contributed to the bobwhites' decline, the major limiting factor in the Post Oak Savannah and Blackland Prairie regions is the scarcity of quality nesting and brood-rearing cover. Bobwhites will typically build their nests in and around the bases of native bunch grasses such as little bluestem, big bluestem, and Indiangrass. Brood rearing cover is slightly different than nesting cover and is typified by weedy fields that attract numerous insects, provide overhead concealment while feeding, and have bare ground underneath for easy movement. Throughout these two regions, much of this type of habitat has been replaced with exotic warm and cool season pasture grasses (ie. Coastal bermudagrass, annual ryegrass), suppressed by continuous and/or overgrazing of livestock, eliminated by large scale farming practices, or has grown too thick from the lack of disturbance. All of the factors that have reduced or eliminated quality nesting and brood rearing cover are correctable, and with careful planning can be restored. Some practices that could be implemented to restore or improve quail habitat include:

1. Restoring improved pastures, or portions thereof, to native grasses and forbs.
    a. Cost-share assistance is available through TPWD for restoring native vegetation on improved pastures and hayfields.
2. Stock rangeland with livestock at the recommended NRCS stocking rate for the area.
3. Rotate livestock through multiple pastures to allow individual pastures time to recover from grazing.
4. Thin dense upland woodlands and forest to promote growth of desirable grasses and forbs.
5. Control rank understory vegetation, such as yaupon, in upland woodlands and forests.
    a. Rank understory vegetation can typically be controlled by with prescribed fire, mechanical clearing, or chemical application.
6. Allow fencerows and cropland borders to grow up with brush, native grasses, and forbs.
7. Allow some cropland to lay fallow for at least one year to provide good brooding cover.
8. Delay mowing or shredding, of pastures and roadsides until at least the end of June to improve successful nesting attempts.
9. Plant erodable areas, and field borders on cropland with a mixture of native bunch grasses and forbs.
10. Burn, or disk pastures every 2 - 3 years to remove excessive plant litter, improve production from native grasses, and encourage forbs, especially legumes.

The loss of adequate low growing woody cover (less than 6 ft. tall), such as plum, sumac, grape, and greenbriar thickets, has also negatively impacted the bobwhites' habitat. Low growing cover of this type is very important to the bobwhite because it protects them from predators and the elements. Cover patches should be in close proximity to one another, typically about 30-100 feet apart. Additionally, cover needs to be close to, or adjacent to, a food source such as a weedy field or cultivated crop. Good low growing cover can be easily provided with brushy thickets, overgrown fencerows, constructing brush piles, or protecting patches of prickly pear cactus. When possible, cover should be disbursed throughout openings and not only along the edges. Cover patches distributed throughout openings will make the entire area usable for quail rather than being limited only to the edges.

Cropland, especially those planted with grain sorghum, corn, or wheat can be very beneficial to bobwhites if managed in a fashion suitable to the birds needs. Bobwhites can thrive in cultivated areas where acreage is relatively small, irregular in shape, and is broken up by idle areas. Idle areas such as fencerows, ditches, and field borders that break up vast cultivated acreage's are very important to making the land suitable to bobwhites. Idle areas must consist of native vegetation, such as perennial bunch grasses, seed producing forbs, and brush. Idle areas planted or seeded with exotic grasses, such as bermudagrass, are of no value to bobwhites. Other practices that will make cultivated land more quail friendly include:

1. Leave a few rows on the outer edge of fields un-harvested.
2. Avoid treating field borders and the outer few rows with chemicals.
3. Reduce field size by leaving 15-30 ft. wide fallow strips throughout.
4. Allow a few fields to lay fallow 1-2 years to provide good brooding habitat.
5. Establish native grasses, forbs, and brush in erodable areas, field borders and along waterways.

Cost share assistance is available through the USDA's Conservation Reserve Program (CRP) and the Environmental Quality Incentive Program (EQIP) for establishing filter strips, riparian buffers, and grass waterways.

Although the future for bobwhite quail in the Post Oak Savannah and Blackland Prairie regions currently appears bleak, it is not too late make the necessary changes. The key to bringing back the bobwhite lies in the hands of the farmers and ranches of these regions. By understanding the specific habitat needs of the bobwhite, and managing the land to provide for these needs on a year round basis, hopefully we can bring the population of this popular game bird back to where it was 20 years ago.

For assistance in developing a habitat management plan for your property, please contact your local Texas Parks and Wildlife Biologist.

Locate the Texas Parks and Wildlife biologist in your area .

To learn more about the upland game species of the Post Oak Savannah and Blackland Prairie, their habitat and management, click on the appropriate link located on the sidebar.

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Last modified: February 9, 2007, 2:30 pm

AUSTIN COUNTY

AMPHIBIANS

		Federal Status	State Status
Houston toad	*Bufo houstonensis*	LE	E

endemic; sandy substrate, water in pools, ephemeral pools, stock tanks; breeds in spring especially after rains; burrows in soil of adjacent uplands when inactive; breeds February-June; associated with soils of the Sparta, Carrizo, Goliad, Queen City, Recklaw, Weches, and Willis geologic formations

BIRDS

		Federal Status	State Status
American Peregrine Falcon	*Falco peregrinus anatum*	DL	T

year-round resident and local breeder in west Texas, nests in tall cliff eyries; also, migrant across state from more northern breeding areas in US and Canada, winters along coast and farther south; occupies wide range of habitats during migration, including urban, concentrations along coast and barrier islands; low-altitude migrant, stopovers at leading landscape edges such as lake shores, coastlines, and barrier islands.

Arctic Peregrine Falcon — *Falco peregrinus tundrius* — DL

migrant throughout state from subspecies' far northern breeding range, winters along coast and farther south; occupies wide range of habitats during migration, including urban, concentrations along coast and barrier islands; low-altitude migrant, stopovers at leading landscape edges such as lake shores, coastlines, and barrier islands.

Attwater's Greater Prairie-Chicken — *Tympanuchus cupido attwateri* — LE — E

this county within historic range; endemic; open prairies of mostly thick grass one to three feet tall; from near sea level to 200 feet along coastal plain on upper two-thirds of Texas coast; males form communal display flocks during late winter-early spring; booming grounds important; breeding February-July

Bald Eagle — *Haliaeetus leucocephalus* — DL — T

found primarily near rivers and large lakes; nests in tall trees or on cliffs near water; communally roosts, especially in winter; hunts live prey, scavenges, and pirates food from other birds

Henslow's Sparrow — *Ammodramus henslowii*

wintering individuals (not flocks) found in weedy fields or cut-over areas where lots of bunch grasses occur along with vines and brambles; a key component is bare ground for running/walking

Interior Least Tern — *Sterna antillarum athalassos* — LE — E

subspecies is listed only when inland (more than 50 miles from a coastline); nests along sand and gravel bars within braided streams, rivers; also know to nest on man-made structures (inland beaches, wastewater treatment plants, gravel mines, etc); eats small fish and crustaceans, when breeding forages within a few hundred feet of colony

Mountain Plover — *Charadrius montanus*

breeding: nests on high plains or shortgrass prairie, on ground in shallow depression; nonbreeding: shortgrass plains and bare, dirt (plowed) fields; primarily insectivorous

Peregrine Falcon — *Falco peregrinus* — DL — T

AUSTIN COUNTY

BIRDS		Federal Status	State Status

both subspecies migrate across the state from more northern breeding areas in US and Canada to winter along coast and farther south; subspecies (F. p. anatum) is also a resident breeder in west Texas; the two subspecies' listing statuses differ, F.p. tundrius is no longer listed in Texas; but because the subspecies are not easily distinguishable at a distance, reference is generally made only to the species level; see subspecies for habitat.

Western Burrowing Owl	*Athene cunicularia hypugaea*		

open grasslands, especially prairie, plains, and savanna, sometimes in open areas such as vacant lots near human habitation or airports; nests and roosts in abandoned burrows

White-faced Ibis	*Plegadis chihi*		T

prefers freshwater marshes, sloughs, and irrigated rice fields, but will attend brackish and saltwater habitats; nests in marshes, in low trees, on the ground in bulrushes or reeds, or on floating mats

White-tailed Hawk	*Buteo albicaudatus*		T

near coast on prairies, cordgrass flats, and scrub-live oak; further inland on prairies, mesquite and oak savannas, and mixed savanna-chaparral; breeding March-May

Whooping Crane	*Grus americana*	LE	E

potential migrant via plains throughout most of state to coast; winters in coastal marshes of Aransas, Calhoun, and Refugio counties

Wood Stork	*Mycteria americana*		T

forages in prairie ponds, flooded pastures or fields, ditches, and other shallow standing water, including salt-water; usually roosts communally in tall snags, sometimes in association with other wading birds (i.e. active heronries); breeds in Mexico and birds move into Gulf States in search of mud flats and other wetlands, even those associated with forested areas; formerly nested in Texas, but no breeding records since 1960

FISHES		Federal Status	State Status
Sharpnose shiner	*Notropis oxyrhynchus*	C	

endemic to Brazos River drainage; also, apparently introduced into adjacent Colorado River drainage; large turbid river, with bottom a combination of sand, gravel, and clay-mud

INSECTS		Federal Status	State Status
A mayfly	*Pseudocentroptiloides morihari*		

mayflies distinguished by aquatic larval stage; adult stage generally found in shoreline vegetation

MAMMALS		Federal Status	State Status
Louisiana black bear	*Ursus americanus luteolus*	LT	T

possible as transient; bottomland hardwoods and large tracts of inaccessible forested areas

Plains spotted skunk	*Spilogale putorius interrupta*		

AUSTIN COUNTY

MAMMALS

		Federal Status	State Status

catholic; open fields, prairies, croplands, fence rows, farmyards, forest edges, and woodlands; prefers wooded, brushy areas and tallgrass prairie

Red wolf	*Canis rufus*	LE	E

extirpated; formerly known throughout eastern half of Texas in brushy and forested areas, as well as coastal prairies

MOLLUSKS

		Federal Status	State Status
False spike mussel	*Quincuncina mitchelli*		

substrates of cobble and mud, with water lilies present; Rio Grande, Brazos, Colorado, and Guadalupe (historic) river basins

Pistolgrip	*Tritogonia verrucosa*		

stable substrate, rock, hard mud, silt, and soft bottoms, often buried deeply; east and central Texas, Red through San Antonio River basins

Rock pocketbook	*Arcidens confragosus*		

mud, sand, and gravel substrates of medium to large rivers in standing or slow flowing water, may tolerate moderate currents and some reservoirs, east Texas, Red through Guadalupe River basins

Smooth pimpleback	*Quadrula houstonensis*		

small to moderate streams and rivers as well as moderate size reservoirs; mixed mud, sand, and fine gravel, tolerates very slow to moderate flow rates, appears not to tolerate dramatic water level fluctuations, scoured bedrock substrates, or shifting sand bottoms, lower Trinity (questionable), Brazos, and Colorado River basins

Texas fawnsfoot	*Truncilla macrodon*		

little known; possibly rivers and larger streams, and intolerant of impoundment; flowing rice irrigation canals, possibly sand, gravel, and perhaps sandy-mud bottoms in moderate flows; Brazos and Colorado River basins

REPTILES

		Federal Status	State Status
Alligator snapping turtle	*Macrochelys temminckii*		T

perennial water bodies; deep water of rivers, canals, lakes, and oxbows; also swamps, bayous, and ponds near deep running water; sometimes enters brackish coastal waters; usually in water with mud bottom and abundant aquatic vegetation; may migrate several miles along rivers; active March-October; breeds April-October

Smooth green snake	*Liochlorophis vernalis*		T

Gulf Coastal Plain; mesic coastal shortgrass prairie vegetation; prefers dense vegetation

Texas horned lizard	*Phrynosoma cornutum*		T

AUSTIN COUNTY

REPTILES		Federal Status	State Status

open, arid and semi-arid regions with sparse vegetation, including grass, cactus, scattered brush or scrubby trees; soil may vary in texture from sandy to rocky; burrows into soil, enters rodent burrows, or hides under rock when inactive; breeds March-September

Timber/Canebrake rattlesnake	*Crotalus horridus*		T

swamps, floodplains, upland pine and deciduous woodlands, riparian zones, abandoned farmland; limestone bluffs, sandy soil or black clay; prefers dense ground cover, i.e. grapevines or palmetto

PLANTS		Federal Status	State Status
Shinner's sunflower	*Helianthus occidentalis ssp plantagineus*		

mostly in prairies on the Coastal Plain, with several slightly disjunct populations in the Pineywoods and South Texas Brush Country

Texas meadow-rue	*Thalictrum texanum*		

Texas endemic; mostly found in woodlands and woodland margins on soils with a surface layer of sandy loam, but it also occurs on prairie pimple mounds; both on uplands and creek terraces, but perhaps most common on claypan savannas; soils are very moist during its active growing season; flowering/fruiting (January-)February-May, withering by midsummer, foliage reappears in late fall(November) and may persist through the winter

FANNIN COUNTY

	BIRDS	Federal Status	State Status
American Peregrine Falcon	*Falco peregrinus anatum*	DL	T

year-round resident and local breeder in west Texas, nests in tall cliff eyries; also, migrant across state from more northern breeding areas in US and Canada, winters along coast and farther south; occupies wide range of habitats during migration, including urban, concentrations along coast and barrier islands; low-altitude migrant, stopovers at leading landscape edges such as lake shores, coastlines, and barrier islands.

Arctic Peregrine Falcon	*Falco peregrinus tundrius*	DL	

migrant throughout state from subspecies’ far northern breeding range, winters along coast and farther south; occupies wide range of habitats during migration, including urban, concentrations along coast and barrier islands; low-altitude migrant, stopovers at leading landscape edges such as lake shores, coastlines, and barrier islands.

Bald Eagle	*Haliaeetus leucocephalus*	DL	T

found primarily near rivers and large lakes; nests in tall trees or on cliffs near water; communally roosts, especially in winter; hunts live prey, scavenges, and pirates food from other birds

Cerulean Warbler	*Dendroica cerulea*		

treetops of riverbank woodlands, swamps, and bottomlands; mainly insectivorous

Eskimo Curlew	*Numenius borealis*	LE	E

historic; nonbreeding: grasslands, pastures, plowed fields, and less frequently, marshes and mudflats

Henslow's Sparrow	*Ammodramus henslowii*		

wintering individuals (not flocks) found in weedy fields or cut-over areas where lots of bunch grasses occur along with vines and brambles; a key component is bare ground for running/walking

Interior Least Tern	*Sterna antillarum athalassos*	LE	E

subspecies is listed only when inland (more than 50 miles from a coastline); nests along sand and gravel bars within braided streams, rivers; also know to nest on man-made structures (inland beaches, wastewater treatment plants, gravel mines, etc); eats small fish and crustaceans, when breeding forages within a few hundred feet of colony

Peregrine Falcon	*Falco peregrinus*	DL	T

both subspecies migrate across the state from more northern breeding areas in US and Canada to winter along coast and farther south; subspecies (F. p. anatum) is also a resident breeder in west Texas; the two subspecies’ listing statuses differ, F.p. tundrius is no longer listed in Texas; but because the subspecies are not easily distinguishable at a distance, reference is generally made only to the species level; see subspecies for habitat.

Piping Plover	*Charadrius melodus*	LT	T

wintering migrant along the Texas Gulf Coast; beaches and bayside mud or salt flats

Wood Stork	*Mycteria americana*		T

FANNIN COUNTY

BIRDS		Federal Status	State Status

forages in prairie ponds, flooded pastures or fields, ditches, and other shallow standing water, including salt-water; usually roosts communally in tall snags, sometimes in association with other wading birds (i.e. active heronries); breeds in Mexico and birds move into Gulf States in search of mud flats and other wetlands, even those associated with forested areas; formerly nested in Texas, but no breeding records since 1960

FISHES		Federal Status	State Status
Blackside darter	*Percina maculata*		T

Red, Sulfur and Cypress River basins; clear, gravelly streams; prefers pools with some current, or even quiet pools, to swift riffles

Blue sucker	*Cycleptus elongatus*		T

larger portions of major rivers in Texas; usually in channels and flowing pools with a moderate current; bottom type usually of exposed bedrock, perhaps in combination with hard clay, sand, and gravel; adults winter in deep pools and move upstream in spring to spawn on riffles

Creek chubsucker	*Erimyzon oblongus*		T

tributaries of the Red, Sabine, Neches, Trinity, and San Jacinto rivers; small rivers and creeks of various types; seldom in impoundments; prefers headwaters, but seldom occurs in springs; young typically in headwater rivulets or marshes; spawns in river mouths or pools, riffles, lake outlets, upstream creeks

Goldeye	*Hiodon alosoides*		

Red River basin below reservoir; spawns spring to July in shallow firm-bottomed backwaters or gravel shoals in tributaries, eggs semibuoyant drift downstream or to quiet water; adults in quiet turbid water of medium to large lowland rivers, small lakes, marshes and muddy shallows connected to them; young feed on microcrustaceans and other inverts; adults on surface water insects, also frogs, fishes, and small mammals

Orangebelly darter	*Etheostoma radiosum*		

Red through Angelina River basins; just headwaters ranging from high gradient streams to more sluggish lowland streams, gravel and rubble riffles preferred; eggs buried in gravel and riffle raceways, post-larvae live in quiet water, move into progressively faster water as they mature, young feed mostly on copepods and cladocerans, adults on mayfly and fly larvae, spawn late February through mid-April in eastern Texas

Paddlefish	*Polyodon spathula*		T

prefers large, free-flowing rivers, but will frequent impoundments with access to spawning sites; spawns in fast, shallow water over gravel bars; larvae may drift from reservoir to reservoir

Shovelnose sturgeon	*Scaphirhynchus platorynchus*		T

open, flowing channels with bottoms of sand or gravel; spawns over gravel or rocks in an area with a fast current; Red River below reservoir and rare occurrence in Rio Grande

Taillight shiner	*Notropis maculatus*		

Sulfur River and Big Cypress Bayou; mostly headwaters, typically large sluggish, mud-bottomed small to large streams and lakes, usually with some aquatic vegetation; spawns March-October in backwaters and pools; feeds mainly on insect larva and cladocerans, also algae

FANNIN COUNTY

FISHES		Federal Status	State Status
Western sand darter	*Ammocrypta clara*		

Red and Sabine River basins; clear to slightly turbid water of medium to large rivers that have moderate to swift currents, primarily over extensive areas of sandy substrate

INSECTS		Federal Status	State Status
American burying beetle	*Nicrophorus americanus*	LE	

varies widely from oak-hickory and coniferous forest ridges tops or hillsides to riparian corridors and valley floor pastures; extremely xeric, saturated, or loose sandy soils unsuitable; adults primarily above ground, eggs in soil adjacent to buried carcass, teneral adults overwinter in soil

MAMMALS		Federal Status	State Status
Black bear	*Ursus americanus*	T/SA;NL	T

bottomland hardwoods and large tracts of inaccessible forested areas; due to field characteristics similar to Louisiana Black Bear (LT, T), treat all east Texas black bears as federal and state listed Threatened

Plains spotted skunk *Spilogale putorius interrupta*

catholic; open fields, prairies, croplands, fence rows, farmyards, forest edges, and woodlands; prefers wooded, brushy areas and tallgrass prairie

Red wolf	*Canis rufus*	LE	E

extirpated; formerly known throughout eastern half of Texas in brushy and forested areas, as well as coastal prairies

MOLLUSKS		Federal Status	State Status
Common pimpleback	*Quadrula pustulosa*		

small streams to larger rivers, and associated with nearly every bottom type except deep shifting sands; Red River downstream of Lake Texoma and possibly Big Cypress Bayou and lower Sulphur river basins

Fawnsfoot *Truncilla donaciformis*

small and large rivers especially on sand, mud, rocky mud, and sand and gravel, also silt and cobble bottoms in still to swiftly flowing waters; Red (historic), Cypress (historic), Sabine (historic), Neches, Trinity, and San Jacinto River basins.

Pistolgrip *Tritogonia verrucosa*

stable substrate, rock, hard mud, silt, and soft bottoms, often buried deeply; east and central Texas, Red through San Antonio River basins

Plain pocketbook *Lampsilis cardium*

small creeks and large rivers, flowing waters, occasionally oxbows or slackwater areas of sandy-bottomed rivers and reservoirs on sand, sand-gravel, or sand-mud but not typically in dense beds; Red and Cypress River basins

FANNIN COUNTY

MOLLUSKS

		Federal Status	State Status
Rock pocketbook	*Arcidens confragosus*		

mud, sand, and gravel substrates of medium to large rivers in standing or slow flowing water, may tolerate moderate currents and some reservoirs, east Texas, Red through Guadalupe River basins

Wabash pigtoe	*Fusconaia flava*		

creeks to large rivers on mud, sand, and gravel from all habitats except deep shifting sands; found in moderate to swift current velocities; east Texas River basins, Red through San Jacinto River basins; elsewhere occurs in reservoirs and lakes with no flow

White heelsplitter	*Lasmigona complanata*		

typically large rivers and streams with sluggish, turbid waters, on mud or mud-gravel bottoms; also smaller streams and reservoirs usually deep in soft mud or occasionally among rocks; quiet areas of otherwise swift streams; Red River with unsuccessful introductions into the upper Trinity River System

REPTILES

		Federal Status	State Status
Alligator snapping turtle	*Macrochelys temminckii*		T

perennial water bodies; deep water of rivers, canals, lakes, and oxbows; also swamps, bayous, and ponds near deep running water; sometimes enters brackish coastal waters; usually in water with mud bottom and abundant aquatic vegetation; may migrate several miles along rivers; active March-October; breeds April-October

Texas horned lizard	*Phrynosoma cornutum*		T

open, arid and semi-arid regions with sparse vegetation, including grass, cactus, scattered brush or scrubby trees; soil may vary in texture from sandy to rocky; burrows into soil, enters rodent burrows, or hides under rock when inactive; breeds March-September

Timber/Canebrake rattlesnake	*Crotalus horridus*		T

swamps, floodplains, upland pine and deciduous woodlands, riparian zones, abandoned farmland; limestone bluffs, sandy soil or black clay; prefers dense ground cover, i.e. grapevines or palmetto

TEXAS PARKS AND WILDLIFE

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Species Search Results for 'Fort Bend'

Taxon	Common Name	Scientific Name	Federal Status	State Status	County Range
Amphibians	Houston toad	Bufo houstonensis	LE	E	View Map
Birds	Henslow's Sparrow	Ammodramus henslowii			View Map
Birds	Western Burrowing Owl	Athene cunicularia hypugaea			View Map
Birds	White-tailed Hawk	Buteo albicaudatus		T	View Map
Birds	Peregrine Falcon	Falco peregrinus	DL	T	View Map
Birds	American Peregrine Falcon	Falco peregrinus anatum	DL	T	View Map
Birds	Arctic Peregrine Falcon	Falco peregrinus tundrius	DL		View Map
Birds	Whooping Crane	Grus americana	LE	E	View Map
Birds	Bald Eagle	Haliaeetus leucocephalus	DL	T	View Map
Birds	Wood Stork	Mycteria americana		T	View Map
Birds	White-faced Ibis	Plegadis chihi		T	View Map
Birds	Interior Least Tern	Sterna antillarum athalassos	LE	E	View Map
Birds	Attwater's Greater Prairie-Chicken	Tympanuchus cupido attwateri	LE	E	View Map
Fishes	American eel	Anguilla rostrata			View Map
Fishes	Sharpnose shiner	Notropis oxyrhynchus	C		View Map
Mammals	Red wolf	Canis rufus	LE	E	View Map
Mammals	Plains spotted skunk	Spilogale putorius interrupta			View Map
Mammals	Louisiana black bear	Ursus americanus luteolus	LT	T	View Map
Mollusks	Rock pocketbook	Arcidens confragosus			View Map
Mollusks	Smooth pimpleback	Quadrula houstonensis			View Map
Mollusks	False spike mussel	Quincuncina mitchelli			View Map
Mollusks	Pistolgrip	Tritogonia verrucosa			View Map
Mollusks	Texas fawnsfoot	Truncilla macrodon			View Map
Plants	Texas prairie dawn	Hymenoxys texana	LE	E	View Map
Plants	Threeflower broomweed	Thurovia triflora			View Map
Reptiles	Timber/Canebrake rattlesnake	Crotalus horridus		T	View Map
Reptiles	Alligator snapping turtle	Macrochelys temminckii		T	View Map
Reptiles	Texas horned lizard	Phrynosoma cornutum		T	View Map

FREESTONE COUNTY

		AMPHIBIANS	Federal Status	State Status
Houston toad	*Bufo houstonensis*		LE	E

endemic; sandy substrate, water in pools, ephemeral pools, stock tanks; breeds in spring especially after rains; burrows in soil of adjacent uplands when inactive; breeds February-June; associated with soils of the Sparta, Carrizo, Goliad, Queen City, Recklaw, Weches, and Willis geologic formations

		BIRDS	Federal Status	State Status
American Peregrine Falcon	*Falco peregrinus anatum*		DL	T

year-round resident and local breeder in west Texas, nests in tall cliff eyries; also, migrant across state from more northern breeding areas in US and Canada, winters along coast and farther south; occupies wide range of habitats during migration, including urban, concentrations along coast and barrier islands; low-altitude migrant, stopovers at leading landscape edges such as lake shores, coastlines, and barrier islands.

Arctic Peregrine Falcon — *Falco peregrinus tundrius* — DL

migrant throughout state from subspecies' far northern breeding range, winters along coast and farther south; occupies wide range of habitats during migration, including urban, concentrations along coast and barrier islands; low-altitude migrant, stopovers at leading landscape edges such as lake shores, coastlines, and barrier islands.

Bachman's Sparrow — *Aimophila aestivalis* — T

open pine woods with scattered bushes and grassy understory in Pineywoods region, brushy or overgrown grassy hillsides, overgrown fields with thickets and brambles, grassy orchards; remnant grasslands in Post Oak Savannah region; nests on ground against grass tuft or under low shrub

Bald Eagle — *Haliaeetus leucocephalus* — DL — T

found primarily near rivers and large lakes; nests in tall trees or on cliffs near water; communally roosts, especially in winter; hunts live prey, scavenges, and pirates food from other birds

Henslow's Sparrow — *Ammodramus henslowii*

wintering individuals (not flocks) found in weedy fields or cut-over areas where lots of bunch grasses occur along with vines and brambles; a key component is bare ground for running/walking

Interior Least Tern — *Sterna antillarum athalassos* — LE — E

subspecies is listed only when inland (more than 50 miles from a coastline); nests along sand and gravel bars within braided streams, rivers; also know to nest on man-made structures (inland beaches, wastewater treatment plants, gravel mines, etc); eats small fish and crustaceans, when breeding forages within a few hundred feet of colony

Peregrine Falcon — *Falco peregrinus* — DL — T

FREESTONE COUNTY

BIRDS

Federal Status State Status

both subspecies migrate across the state from more northern breeding areas in US and Canada to winter along coast and farther south; subspecies (F. p. anatum) is also a resident breeder in west Texas; the two subspecies' listing statuses differ, F.p. tundrius is no longer listed in Texas; but because the subspecies are not easily distinguishable at a distance, reference is generally made only to the species level; see subspecies for habitat.

		Federal Status	State Status
Piping Plover	*Charadrius melodus*	LT	T

wintering migrant along the Texas Gulf Coast; beaches and bayside mud or salt flats

Whooping Crane	*Grus americana*	LE	E

potential migrant via plains throughout most of state to coast; winters in coastal marshes of Aransas, Calhoun, and Refugio counties

Wood Stork	*Mycteria americana*		T

forages in prairie ponds, flooded pastures or fields, ditches, and other shallow standing water, including salt-water; usually roosts communally in tall snags, sometimes in association with other wading birds (i.e. active heronries); breeds in Mexico and birds move into Gulf States in search of mud flats and other wetlands, even those associated with forested areas; formerly nested in Texas, but no breeding records since 1960

MAMMALS

Federal Status State Status

Plains spotted skunk	*Spilogale putorius interrupta*		

catholic; open fields, prairies, croplands, fence rows, farmyards, forest edges, and woodlands; prefers wooded, brushy areas and tallgrass prairie

Red wolf	*Canis rufus*	LE	E

extirpated; formerly known throughout eastern half of Texas in brushy and forested areas, as well as coastal prairies

Southeastern myotis bat	*Myotis austroriparius*		

roosts in cavity trees of bottomland hardwoods, concrete culverts, and abandoned man-made structures

MOLLUSKS

Federal Status State Status

Creeper (squawfoot)	*Strophitus undulatus*		

small to large streams, prefers gravel or gravel and mud in flowing water; Colorado, Guadalupe, San Antonio, Neches (historic), and Trinity (historic) River basins

Fawnsfoot	*Truncilla donaciformis*		

small and large rivers especially on sand, mud, rocky mud, and sand and gravel, also silt and cobble bottoms in still to swiftly flowing waters; Red (historic), Cypress (historic), Sabine (historic), Neches, Trinity, and San Jacinto River basins.

Little spectaclecase	*Villosa lienosa*		

creeks, rivers, and reservoirs, sandy substrates in slight to moderate current, usually along the banks in slower currents; east Texas, Cypress through San Jacinto River basins

FREESTONE COUNTY

MOLLUSKS		Federal Status	State Status
Louisiana pigtoe	*Pleurobema riddellii*		

streams and moderate-size rivers, usually flowing water on substrates of mud, sand, and gravel; not generally known from impoundments; Sabine, Neches, and Trinity (historic) River basins

Pistolgrip *Tritogonia verrucosa*

stable substrate, rock, hard mud, silt, and soft bottoms, often buried deeply; east and central Texas, Red through San Antonio River basins

Rock pocketbook *Arcidens confragosus*

mud, sand, and gravel substrates of medium to large rivers in standing or slow flowing water, may tolerate moderate currents and some reservoirs, east Texas, Red through Guadalupe River basins

Sandbank pocketbook *Lampsilis satura*

small to large rivers with moderate flows and swift current on gravel, gravel-sand, and sand bottoms; east Texas, Sulfur south through San Jacinto River basins; Neches River

Texas heelsplitter *Potamilus amphichaenus*

quiet waters in mud or sand and also in reservoirs. Sabine, Neches, and Trinity River basins

Texas pigtoe *Fusconaia askewi*

rivers with mixed mud, sand, and fine gravel in protected areas associated with fallen trees or other structures; east Texas River basins, Sabine through Trinity rivers as well as San Jacinto River

Wabash pigtoe *Fusconaia flava*

creeks to large rivers on mud, sand, and gravel from all habitats except deep shifting sands; found in moderate to swift current velocities; east Texas River basins, Red through San Jacinto River basins; elsewhere occurs in reservoirs and lakes with no flow

REPTILES		Federal Status	State Status
Alligator snapping turtle	*Macrochelys temminckii*		T

perennial water bodies; deep water of rivers, canals, lakes, and oxbows; also swamps, bayous, and ponds near deep running water; sometimes enters brackish coastal waters; usually in water with mud bottom and abundant aquatic vegetation; may migrate several miles along rivers; active March-October; breeds April-October

Texas garter snake *Thamnophis sirtalis annectens*

wet or moist microhabitats are conducive to the species occurrence, but is not necessarily restricted to them; hibernates underground or in or under surface cover; breeds March-August

Texas horned lizard	*Phrynosoma cornutum*		T

open, arid and semi-arid regions with sparse vegetation, including grass, cactus, scattered brush or scrubby trees; soil may vary in texture from sandy to rocky; burrows into soil, enters rodent burrows, or hides under rock when inactive; breeds March-September

Timber/Canebrake rattlesnake	*Crotalus horridus*		T

FREESTONE COUNTY

REPTILES		Federal Status	State Status

swamps, floodplains, upland pine and deciduous woodlands, riparian zones, abandoned farmland; limestone bluffs, sandy soil or black clay; prefers dense ground cover, i.e. grapevines or palmetto

PLANTS		Federal Status	State Status
Chapman's yellow-eyed grass	*Xyris chapmanii*		

mostly in soft, spongy, peaty substrates in deep muck seepage bogs; mostly in muckiest parts of hillside seepage bogs; flowering August-September, with seed maturing September-October

Large-fruited sand-verbena	*Abronia macrocarpa*	LE	E

Texas endemic; restricted to sparse herbaceous vegetation in deep, somewhat excessively drained sands in openings in Post oak woodlands, sometimes in active blowouts; all known sites underlain by sandy Eocene strata; flowering late February-May (-June; also in the fall following periods of high rainfall)

Navasota ladies'-tresses	*Spiranthes parksii*	LE	E

Texas endemic; openings in post oak woodlands in sandy loams along upland drainages or intermittent streams, often in areas with suitable hydrologic factors, such as a perched water table associated with the underlying claypan; flowering populations fluctuate widely from year to year, an individual plant does not flower every year; flowering late October-early November (-early December)

Rough-stem aster	*Symphyotrichum puniceum var scabricaule*		

relatively open sites in saturated soils associated with seepage areas, bogs, marshes, ponds, drainages, and degraded wetland remnants on the Queen City, Carrizo, and Sparta sand formations; flowering late September-early November

American Peregrine Falcon (*Falco peregrinus anatum)*

Photo ©TPWD

OTHER NAMES

Peregrine Falcon

TEXAS STATUS

Endangered

PROTECTION STATUS NOTES

Federally listed as endangered in 1970. Delisted August 25, 1999.

DESCRIPTION

The Anatum Peregrine is intermediate in terms of color and size. It has a salmon or peach-tinged breast, with stronger barring across the breast than the Tundra subspecies. The back is slightly darker than in the Tundra Peregrine, but still has bluish-gray tinges, especially on the upperwing coverts and uppertail coverts. The moustache on the Anatum Peregrine is very wide, and the auricular patch is often very small. Immatures have a solid brown crown and forehead, and have a fairly wide moustache, although their auricular patch is often larger than that of adults. They have heavy brown streaks on their cream colored breast and belly, and have small buffy edges to the feathers on their back.

DISTRIBUTION

The American Peregrine is a resident of the Trans-Pecos region, including the Chisos, Davis, and Guadalupe mountain ranges. Listed as a Texas endangered species since 1974.

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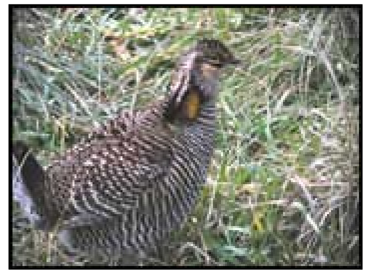
Attwater's Prairie Chicken (*Tympanuchus cupido attwateri)*



TPWD ©

OTHER NAMES

Greater Prairie Chicken

TEXAS STATUS

Endangered

U.S. STATUS

Endangered, Listed 3/11/1967

DESCRIPTION

The Attwater's prairie chicken is a small, brown bird about 17 inches long, with short, rounded, dark tail. Males have large orange air sacs on the sides of their necks. During mating season, males make a "booming" sound, amplified by inflating the air sacs on their necks, that can be heard 1/2 mile away.

LIFE HISTORY

Attwater's prairie chickens live on coastal prairie grasslands with tall grasses such as little bluestem, Indian grass, and switchgrass. The birds like a variety of tall and short grasses in their habitat. They gather to choose a mate in an area of bare ground or short grass where the males can be easily seen by the females. This is called a "booming groundor lek." The males dance and make a booming noise to attract the females. Hens build their nest in tallgrass and usually lay 12 eggs during nesting season. The eggs hatch in April or May. Small green leaves, seeds, and insects form the diet of the Attwater's prairie chicken. Attwater's prairie chickens live about 2-3 years in the wild.

HABITAT

Tall grass coastal prairies are essential to the survival of this species.

DISTRIBUTION

Attwater's prairie chickens are found only on the coastal prairies of Texas.

OTHER

Prairie chickens are endangered because the tallgrass prairie has been plowed for farmland and covered by cities. Habitat has also been lost because of heavy grazing by cattle, although some cattle ranches maintain good grassland habitat suitable for prairie chickens. Their population has declined dramatically since 1993, when an estimated 456 Attwater prairie chickens existed in the wild. In 1994, that estimate dropped to 158 birds, and by 1996, only 42 of these rare birds were left.

For more information

Visit the Attwater's Prairie Chicken National Wildlife Refuge near Eagle Lake. In addition the town of Eagle Lake holds an annual festival to celebrate the Attwater's Prairie Chicken.

See also: **Attwater's birding pages** for more information.

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Black Bear (*Ursus americanus)*

TEXAS STATUS

Threatened

U.S. STATUS

Threatened

DESCRIPTION

See **Bear Safety in Mind: Hunter's Edition** for ways to deal with bears.

The Black Bear is a stocky, large animal, one of the largest mammals in North America. Adults reach a length of 5 to 6 feet, height at the shoulder of 2 to 3 feet, and weigh 200-300 pounds. Although called a "black" bear, colors can range from black to the occasional cinnamon brown. Front claws are generally longer than hind claws. The fur is long and coarse. Although appealing and generally harmless, Black Bears can injure humans when provoked and should be treated with caution.

LIFE HISTORY

At home in the woods and forests, Black Bears are capable of climbing trees, but adult bears generally prefer remaining on the ground. Although classified as a carnivore, the Black Bear is a true omnivore, opportunistically feeding on a wide range of food items. Analysis of scat (bear droppings) shows that vegetable material almost always comprises over half the bear's diet, with insects and other animals comprising a small percentage. In particular, fresh leaves, fruits, berries, nuts, roots, and tubers are favorite foods seasonally, with insects and small mammals eaten when the opportunity arises.

It's easy to see where bears have been. They frequently break the branches of nut-bearing trees while feeding and tear up the ground looking for insects, roots, or tubers. Black Bears in Texas especially relish the succulent base of the sotol plant (Dasylirion). In desert environments, it's common to find partially eaten sotol plants where bears have been. Bears will also strip the bark from trees while looking for insects or juicy pulp, and will often rub themselves on rough bark.

Breeding occurs in June and July. Some biologists believe female Black Bears in Texas hibernate (a prolonged sleep-like habit when body temperature and respiration are drastically reduced), while males do not. The young are born in January or February, while the mother is "hibernating". She normally gives birth to two-to-three cubs every two years.

HABITAT

The American Black Bear is found throughout North America in habitats ranging from swamps to desert scrub. Black Bears were once found through out North America, mostly in forests, but also in deserts and swamps. At least two subspecies of Black Bear are thought to occur in Texas: the Mexican Black Bear

(*Ursus americanus* eremicus) and the New Mexico Black Bear (subspecies U. a. amblyceps). Both are found in West Texas in desert scrub or woodland habitats within scattered mountain ranges, predominantly the Chisos and Guadalupe Mountains. Both subspecies are state-listed as endangered in Texas. The **Louisiana Black Bear** (subspeciesU. a. luteolus) is on the federal threatened species list. It is not known to be found in Texas, although potential habitat exists in the eastern part of the state.

DISTRIBUTION

Today, Black Bears are found predominantly in the Appalachian area of the eastern U.S. across Canada to the Northern Pacific Coast. In addition, Black Bears are found in most of the Gulf Coast states and the Rocky Mountains.

OTHER

If you judge by recent reported sightings, the Black Bear is making a significant comeback in Texas. However, public interest in an animal often has a way of fueling additional sightings, especially during poor visibility conditions. This is true not only with bears, but many other elusive and intriguing animals, such as Mountain Lions or sharks. In other words, some of the bear reports could be false.

From the Big Bend to Austin, bear sightings have surprised biologists and the public alike. On the other hand, at least one sighting per year of Black Bears in the Hill Country is not uncommon. These individuals may be truly wild animals looking for suitable habitat or mates, but it is entirely possible that they are released or escaped captive animals. In any case, the chances of a recently established population of Black Bears in the Hill Country are remote. Central Texans are probably seeing wandering individuals from farther west.

Black Bears are not as dangerous as some people think. For one thing, most of their diet is vegetation, so they may pose less of a threat to livestock than some other predators. And like most animals, they will seldom approach people.

The Black Bear, *Ursus americanus*, is on the state endangered species list. TPWD biologists encourage people to report recent bear sightings to Texas Parks and Wildlife Department. Research is currently underway by the Texas Parks and Wildlife Department to determine the status of Black Bears in Texas. A study is also underway in East Texas to determine habitat suitability in that part of the state.

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Eskimo Curlew (*Numenius borealis*)

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Texas Status

Endangered

U.S. Status

Endangered, Listed 3/11/1967

Description

The Eskimo curlew has warm brown feathers with white speckles. Cinnamon-colored feathers line the undersides of their wings. They have long, dark green, dark brown, or dark grey-blue legs and are about 12 inches in length.

Life History

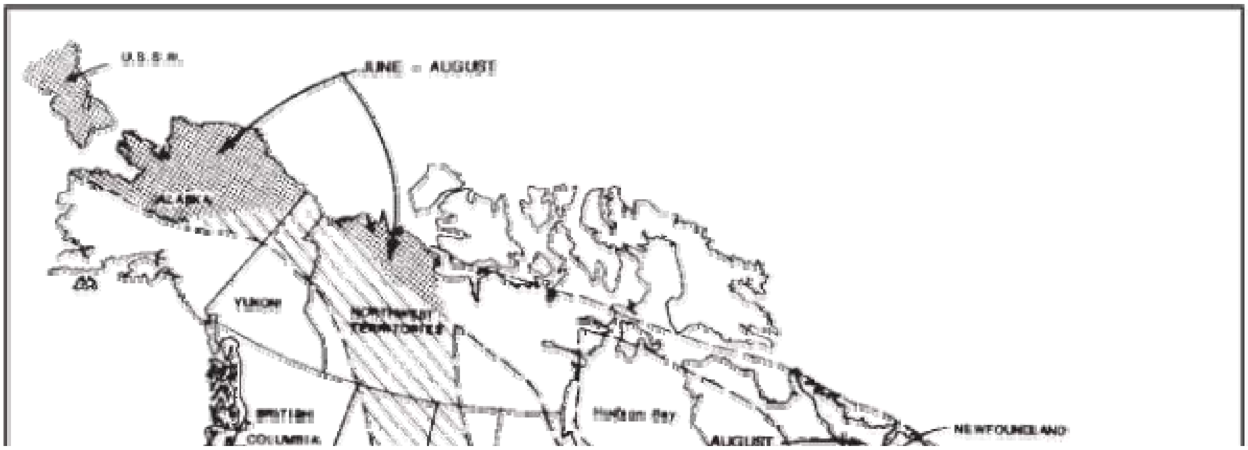
In the mid-1800's, huge flocks of Eskimo Curlew migrated north from South America to their nesting grounds in the Alaskan and Canadian Arctic. Historic reports tell of the skies being full of Eskimo Curlews as they migrated through the prairie states and provinces. One historic report describes a single flock feeding in Nebraska that was said to have covered 40 to 50 acres of ground. During migration, they fed on grasshoppers and other insects on the grasslands of the central United States.

Between 1870 and 1890, unrestricted hunting rapidly reduced populations of Eskimo Curlew. Considered very good to eat, the birds were killed by thousands of market hunters, just as the Passenger Pigeon had been years earlier. The curlew's lack of fear and habit of traveling in large flocks made it an easy target.

Habitat

Arctic tundra and open grasslands provide habitat for Eskimo curlews.

Distribution



Eskimo curlews migrate from breeding grounds in the Arctic tundra through the North American prairies to wintering grounds on the Pampas grasslands of Argentina.

OTHER

In 1916, nongame bird hunting in the United States was stopped by the Migratory Bird Treaty Act, but the Eskimo Curlew did not recover. Conversion of native grasslands to cropland, in the South American wintering area and along the migration route through the tall grass prairies of the United States, is thought to be the reason for the birds' failure to recover.

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Texas Horned Lizard (*Phrynosoma cornutum)*

Photo ©TPWD

OTHER NAMES

Horny Toad

TEXAS STATUS

Threatened

DESCRIPTION

The Texas horned lizard or "horny toad" is a flat-bodied and fierce-looking lizard. The head has numerous horns, all of which are prominent, with two central head spines being much longer than any of the others. This lizard is brownish with two rows of fringed scales along each side of the body. On most Texas horned lizards, a light line can be seen extending from its head down the middle of its back. It is the only species of horned lizard to have dark brown stripes that radiate downward from the eyes and across the top of the head.

HABITAT

They can be found in arid and semiarid habitats in open areas with sparse plant cover. Because horned lizards dig for hibernation, nesting and insulation purposes, they commonly are found in loose sand or loamy soils.

DISTRIBUTION

Texas horned lizards range from the south-central United States to northern Mexico, throughout much of Texas, Oklahoma, Kansas and New Mexico.

OTHER

The Texas horned lizard currently is listed as a threatened species in Texas (federal category C2).

For more information

Check Parks and Wildlife's Texas Horned Lizard Watch for progams and monitoring activities.

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Houston Toad (*Bufo houstonensis)*

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TEXAS STATUS

Endangered

U.S. STATUS

Endangered, Listed 10/13/1970

DESCRIPTION

The Houston toad is 2 to 3.5 inches long. Its general coloration varies from light brown to gray or purplish gray, sometimes with green patches. The pale undersides often have small, dark spots. Males have a dark throat, which appears bluish when distended.

LIFE HISTORY

The Houston toad lives primarily on land. The toads burrow into the sand for protection from cold weather in the winter (hibernation) and hot, dry conditions in the summer (aestivation). Plants that are often present in Houston toad habitat include loblolly pine, post oak, bluejack or sandjack oak, yaupon, and little bluestem.

For breeding, including egg and tadpole development, Houston toads also require still or slow-flowing bodies of water that persist for at least 30 days. These water sources may include ephemeral (temporary) rain pools, flooded fields, blocked drainages of upper creek reaches, wet areas associated with seeps or springs, or more permanent ponds containing shallow water. The toads do best in ponds without predatory fish.

The Houston toad is a year-round resident where found, although its presence can most easily be detected during the breeding season, when males may be heard calling. Males usually call in or near shallow water or from small mounds of soil or grass surrounded by water. Males occasionally call from wooded habitat located within about a 100-yard radius of breeding ponds. The call is a high clear trill that lasts an average of 14 seconds. The call is much like that of the American toad (Bufo americanus), but ususally slightly higher in pitch. The American toad occurs in Texas, but north of the range of the Houston toad.

Houston toads may call from December through June. Most breeding activity takes place in February and March, and is stimulated by warm evenings and high humidity. Toads emerge from hibernation to breed only if moisture and temperature conditions are favorable. Males call females to the breeding pond with a high, clear trill. Females, responding to calling males, move toward the water to mate. The female lays her eggs as long strings in the water, where they are fertilized by the male as they are laid. The eggs hatch within seven days and tadpoles metamorphose (turn into toadlets) between 15 and 100 days, depending on the water temperature.

Young toadlets are about one-half inch long when they complete metamorphosis. They then leave the pond and spend their time feeding and growing in preparation for the next breeding season. Males generally breed when they are a year old, but females may not breed until they are two years old. Houston toads, especially first-year toadlets and juveniles, are active year round under suitable temperature and moisture conditions. Their diet consists mainly of insects and other invertebrates. They live 2 to 3 years.

HABITAT

The Houston toad requires loose, deep sands supporting woodland savannah and still or flowing waters for breeding.

DISTRIBUTION

The largest population of Houston toads exists in Bastrop county.

THREATS AND REASONS FOR DECLINE

Habitat loss and alteration are the most serious threats facing the Houston Toad. Alteration of ephemeral and permanent natural wetlands for urban and agricultural uses eliminates breeding sites. Draining a wetland, or converting an ephemeral wetland to a permanent pond, can eventually cause the Houston toad to decline or be eliminated entirely. Conversion to permanent water not only makes them more vulnerable to predation by snakes, fish, and other predators; but also increases competition and hybridization with closely related species.

Periodic drought is also a threat, particularly long-term drought such as that experienced during the 1950's. Drought may result in the loss or reduction of breeding sites as well as enhanced mortality of toadlets and adults.

Extensive clearing of native vegetation near breeding ponds and on the uplands adjacent to these ponds reduces the quality of breeding, foraging, and resting habitat, and increases the chances of predation and hybridization. Conversion of native grassland and woodland savannah to sod-forming introduced grasses, such as bermudagrass and bahiagrass, eliminates habitat because grass growth is generally too dense for the toad to move freely. Dense sod also inhibits burrowing.

High traffic roads are a barrier to Houston Toad movement, and toads are sometimes killed on roads. Other linear features such as pipelines and transmission lines can create barriers between foraging, hibernating, and breeding sites, especially if native vegetation has been removed.

Continuous grazing (not rotating cattle), heavy stocking rates, and long term fire suppression have caused loss of habitat in a significant part of the toad's range. Historically, periodic fire played an important role in maintaining native bunchgrass communities in loblolly pine and post oak savannah. Due to poor grazing management practices and fire suppression since the arrival of European man, much of the former savannah grasslands of the Post Oak region has grown into brush thickets devoid of herbaceous vegetation. Houston Toads need the herbaceous layer of bunchgrasses for cover and foraging habitat.

Although the toad is believed to be adapted to fire regimes, prescribed burning may result in toad mortality. Frequent and/or severe burns may be detrimental to the toad, particularly for small, fragmented populations. However, increased fuel loads due to prolonged periods of fire prevention may result in very hot wildfires. Additional research is needed to determine the effects of prescribed burning programs.

The invasion of the Red Imported Fire Ant makes it harder to ensure the long-term survival of the Houston Toad. These toads occur in small, scattered populations, and may be more seriously affected by fire ants than species that are more common and widespread. Fire ants kill young toadlets (less than 7-10 days old) moving out of the breeding pond into the surrounding land habitat. Current research shows that fire ants have a devastating impact on local arthropod communities, and thus may also limit the toad's food supply.

There is no specific information on the effects of various chemicals on the Houston Toad, but it is known that amphibians in general are very sensitive to many pollutants, including pesticides and other organic compounds. These chemicals may affect the toad directly, particularly in the tadpole stage, or indirectly by lowering the abundance and diversity of its food supply. Widespread use of pesticides and herbicides from about 1950 to 1975 may also have contributed to declining populations. During this period, DDT and similar non-specific chemicals accumulated in the environment, affecting a wide variety of animal life. Although threats from persistent, non-specific chemicals are not as serious today as in the past, the use of pesticides and herbicides for agricultural and residential purposes may still pose a danger for the Houston Toad.

Although Houston Toad populations are inherently separated because they exist only in areas of deep sandy soil, further fragmentation of habitat due to human activity can be a problem. Widely scattered parcels of habitat may not easily be re-colonized by distant Houston Toads if extensive areas of unsuitable habitat occur between populations, or human impacts eliminate a population.

Ongoing Recovery

Research is continuing into the life history, habitat requirements, and land management practices affecting the Houston Toad. Population surveys are being conducted in areas where toads have been found and in potential habitat areas. Efforts to provide information and educational opportunities to the general public and landowners regarding life history and habitat requirements of the toad are a vital part of the recovery process.

How You Can Help

You can help by protecting pond habitat. Conservation and wise management of native vegetation is important in preserving Houston Toad habitat. You can also help by landscaping with native plants to reduce water and pesticide use, and by proper storage and disposal of household, gardening, and agricultural chemicals. Hopefully, thoughtful and effective compromises between human resource needs and habitat management will allow for the continued survival and recovery of the Houston Toad.

You can be involved with the conservation of Texas' nongame wildlife resources by supporting the Special Nongame and Endangered Species Conservation Fund. Special nongame stamps and decals are available at Texas Parks and Wildlife Department (TPWD) field offices, most state parks, and the License Branch of TPWD headquarters in Austin. Conservation organizations in Texas also welcome your participation and support.

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Interior Least Tern (*Sterna antillarum athalassos)*

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OTHER NAMES

Least Tern

TEXAS STATUS

Endangered

U.S. STATUS

Endangered, Listed 6/27/1985

DESCRIPTION

Least Terns are the smallest North American terns. Adults average 8 to 10 inches in length, with a 20 inch wingspan. Their narrow, pointed wings make them streamlined flyers. Males and females are similar in appearance. Breeding adults are gray above and white below, with a black cap, black nape and eye stripe, white forehead, yellow bill with a black or brown tip, and yellow to orange legs. Hatchlings are about the size of pingpong balls and are yellow and buff with brown mottling. Fledglings (young birds that have left the nest) are grayish brown and buff colored, with white heads, dark bills and eye stripes, and stubby tails. Young terns acquire adult plumage after their first molt at about 1 year, but do not breed until they are 2 to 3 years old. The Least Tern's call has been described as a high pitched "kit,""zeep," or "zreep."

LIFE HISTORY

Interior Least Terns arrive at breeding areas from early April to early June, and spend 3 to 5 months on the breeding grounds. Upon arrival, adult terns usually spend 2 to 3 weeks in noisy courtship. This includes finding a mate, selecting a nest site, and strengthening the pair bond. Courtship often includes the "fish flight", an aerial display involving aerobatics and pursuit, ending in a fish transfer on the ground between two displaying birds. Courtship behaviors also include nest preparation and a variety of postures and vocalizations.

Least Terns nest in colonies, where nests can be as close as 10 feet but are often 30 feet or more apart. The nest is a shallow depression in an open, sandy area, gravelly patch, or exposed flat. Small twigs, pieces of wood, small stones or other debris usually occur near the nest.

Egg-laying begins in late May, with the female laying 2 to 3 eggs over a period of 3 to 5 days. The eggs are pale to olive buff and speckled or streaked with dark purplishbrown, chocolate, or blue-gray markings. Both parents incubate the eggs, with incubation lasting about 20 to 22 days. The chicks hatch within one day of each other and remain in the nest for about a week. As they mature, they begin to wander from the nest, seeking shade and shelter in clumped vegetation and debris. Chicks are capable of flight within 3 weeks, but the parents continue to feed them until fall migration. Least Terns will renest until late July if clutches or broods are lost.

Activities of the Interior Least Tern during the breeding season are limited to the portion of river near the nesting site. Nesting adults defend an area surrounding the nest (territory) against intruders, and terns within a colony will defend any nest within that colony. When defending a territory, the incubating bird will fly up giving an alarm call, and then dive repeatedly at the intruder

The breeding season is usually complete by late August. Prior to migration, the terns gather at staging areas with high fish concentrations. They gather to rest and eat prior to the long flight to southern wintering grounds. Low, wet sand or gravel bars at the mouths of tributary streams and floodplain wetlands are important staging areas. Interior Least Terns often return to the same breeding site, or one nearby, year after year.

Nesting success of terns at a particular location varies greatly from year to year. Because water levels fluctuate and nesting habitats such as sandbars and shorelines change over time, the terns are susceptible to habitat loss and frequent nest and chick loss.

The Interior Least Tern is primarily a fish-eater, feeding in shallow waters of rivers, streams, and lakes. The birds are opportunistic and tend to select any small fish within a certain size range. Feeding behavior involves hovering and diving for small fish and aquatic crustaceans, and occasionally skimming the water surface for insects.

In portions of the range, shorebirds such as the Piping and Snowy plovers often nest in close proximity. The Piping Plover is listed as Threatened by the U.S. Fish and Wildlife Service.

HABITAT

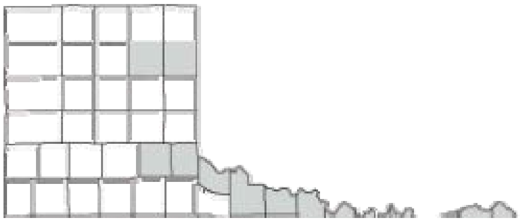
Nesting habitat of the Interior Least Tern includes bare or sparsely vegetated sand, shell, and gravel beaches, sandbars, islands, and salt flats associated with rivers and reservoirs. The birds prefer open habitat, and tend to avoid thick vegetation and narrow beaches. Sand and gravel bars within a wide unobstructed river channel, or open flats along shorelines of lakes and reservoirs, provide favorable nesting habitat. Nesting locations are often at the higher elevations away from the water's edge, since nesting usually starts when river levels are high and relatively small amounts of sand are exposed. The size of nesting areas depends on water levels and the extent of associated sandbars and beaches. Highly adapted to nesting in disturbed sites, terns may move colony sites annually, depending on landscape disturbance and vegetation growth at established colonies.

For feeding, Interior Least Terns need shallow water with an abundance of small fish. Shallow water areas of lakes, ponds, and rivers located close to nesting areas are preferred.

As natural nesting sites have become scarce, the birds have used sand and gravel pits, ash disposal areas of power plants, reservoir shorelines, and other manmade sites.

DISTRIBUTION

There are three subspecies of the Least Tern recognized in the United States. The subspecies are identical in appearance and are



segregated on the basis of
separate breeding ranges. The Eastern or Coastal Least Tern *(Sterna antillarum antillarum)*, which is not federally listed as endangered or threatened, breeds along the Atlantic coast from Maine to Florida and west along the Gulf coast to south Texas. The California Least Tern *(Sterna antillarum browni)*, federally listed as endangered since 1970, breeds along the Pacific coast from central California to southern Baja California. The endangered Interior Least Tern *(Sterna antillarum athalassos)* breeds inland along the Missouri, Mississippi, Colorado, Arkansas, Red, and Rio Grande River systems. Although these subspecies are generally recognized, recent evidence indicates that terns hatched on the Texas coast sometimes breed inland. Some biologists speculate that the interchange between coastal and river populations is greater than once thought.

The Interior Least Tern is migratory, breeding along inland river systems in the United States and wintering along the Central American coast and the northern coast of South America from Venezuela to northeastern Brazil. Historically, the birds bred on sandbars on the Canadian, Red, and Rio Grande River systems in Texas, and on the Arkansas, Missouri, Mississippi, Ohio and Platte River systems in other states. The breeding range extended from Texas to Montana and from eastern Colorado and New Mexico to southern Indiana. It included the braided rivers of Oklahoma and southern Kansas, salt flats of northwest Oklahoma, and alkali flats near the Pecos River in southeast New Mexico.

Today, the Interior Least Tern continues to breed in most of the major river systems, but its distribution is generally restricted to the less altered and more natural or little disturbed river segments. In Texas, Interior Least Terns are found at three reservoirs along the Rio Grande River, on the Canadian River in the northern Panhandle, on the Prairie Dog Town Fork of the Red River in the eastern Panhandle, and along the Red River (Texas/Oklahoma boundary) into Arkansas.

THREATS AND REASONS FOR DECLINE

Channelization, irrigation, and the construction of reservoirs and pools have contributed to the elimination of much of the tern's natural nesting habitat in the major river systems of the Midwest. Discharges from dams built along these river systems pose additional problems for the birds nesting in the remaining habitat. Before rivers were altered, summer flow patterns were more predictable. The nesting habits of the Least Tern evolved to coincide with natural declines in river flows. Today, flow regimes in many rivers differ greatly from historic regimes. High flow periods may now extend into the normal nesting period, thereby reducing the availability of quality nest sites and forcing terns to nest in less than optimum locations. Extreme fluctuations can inundate potential nesting areas, flood existing nests, and dry out feeding areas.

Historical flood regimes scoured areas of vegetation, providing additional nesting habitat. However, diversion of river flows into reservoirs has resulted in encroachment of vegetation and reduced channel width along many rivers, thereby reducing sandbar habitat. Reservoirs also trap much of the sediment load, limiting formation of suitable sandbar habitat.

In Texas and elsewhere, rivers are often the focus of recreational activities. For inland residents, sandbars are the recreational counterpart of coastal beaches. Activities such as fishing, camping, and ATV use on and near sandbar habitat are potential threats to nesting terns. Even sand and gravel pits, reservoirs, and other artificial nesting sites receive a high level of human use. Studies have shown that human presence reduces reproductive success, and human disturbance remains a threat throughout the bird's range.

Water pollution from pesticides and irrigation runoff is another potential threat. Pollutants entering rivers upstream and within breeding areas can adversely affect water quality and fish populations in tern feeding areas. Least Terns are known to accumulate contaminants that can affect reproduction and chick survival. Mercury, selenium, DDT derivatives, and PCBs have been found in Least Terns throughout their range at levels warranting concern, although reproductive difficulties have not been observed.

Finally, too little water in some river channels may be a common problem that reduces the birds' food supply and increases access to nesting areas by humans and predatory mammals. Potential predators include coyotes, gray foxes, raccoons, domestic dogs and cats, raptors, American Crows, Great Egrets, and Great Blue Herons.

ONGOING RECOVERY

State, federal, and private organizations throughout the United States are collaborating to census the birds, conduct research, curtail human disturbance, and provide habitat. Continued monitoring of confirmed and potential colony sites is underway to assess population status and reproductive success. Protective measures, including signs and fences, are being implemented to restrict access to sites most threatened by human disturbance. Vegetation control at occupied sites, chick shelter enhancement, predator control, pollution abatement, and habitat creation/restoration at unoccupied sites are management strategies used to benefit Interior Least Tern populations.

Biologists continue to assess habitat availability and quality throughout the bird's range in Texas, and identify essential habitat for management and protection. Recently, in a cooperative effort between the Texas Parks and Wildlife Department, National Park Service, International Boundary and Water Commission, Comision Internacional de Limites y Aguas, Oficina de Ecologia Estado de Coahuila, and City of Del Rio, warning signs in both Spanish and English were erected to inform visitors about the effects of human disturbance on the terns. Also, the National Park Service recently initiated annual status surveys for Interior Least Terns at Amistad NRA. Finally, public information campaigns concerning Least Tern conservation are a vital part of the recovery process.

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Last modified: June 2, 2009, 3:55 pm

Navasota Ladies'-tresses (*Spiranthes parksii)*

TPWD ©

Texas Status

Endangered

U.S. Status

Endangered, Listed 5/06/1982

Description

There are 14 or 15 different ladies'-tresses in Texas, and during the fall one or another of these orchids can be seen in almost any habitat in the eastern half of the state. Finding ladies-tresses can be difficult, since these orchids are not as conspicuous as their tropical cousins. Most Texas species produce a single slender, twisted spike of tiny white flowers, and in many habitats the ladies-tresses spike is much shorter than surrounding 5 wildflowers.

This member of the orchid family is an erect, slender-stemmed perennial herb, 8-15 inches tall. The roots are clusters of fleshy tubers. Leaves are long and thin and found primarily at ground level, but are usually gone by flowering time. Flowers are creamy white and arranged in a loose spiral up the stem. Conspicuously white-tipped bracts occur underneath each 1/4 inch-long flower. Flower petals are round or oval. The side petals have a green central stripe, and the lip (bottom petal) is distinctly ragged.

Life History

Navasota ladies'-tresses bud from early to late October, flower from mid-October to mid-November, and form fruit from mid-October to the first frost (usually late November). The fruit breaks apart during mid-November and December. Each fruit normally contains thousands of microscopic seeds which are not easily cultivated. After frost, the plants die back and do not reappear until early spring, when basal rosettes can be seen.

Populations of Navasota ladies'-tresses are known to fluctuate from year to year. It is thought that cool, wet conditions (without hard frosts) between January and May provide ideal growing conditions for this orchid. Like other orchids, Navasota ladies'-tresses are often found in areas that are slightly wetter than surrounding areas of the landscape, although surface moisture may not be obvious.

This species has a limited range and low population numbers. It has been impacted by habitat loss and degradation due to urban development (primarily in the Bryan/College Station area), road construction, lignite mining, and oil and gas development. Collection by hobbyists and unscrupulous commercial operators remains a threat, especially since orchids tend to attract wide and intense interest.

These orchids appear to be adapted to common rangeland management practices used in the post oak savannah region. Controlled fire, proper grazing, and selective brush management are not considered detrimental. When needed, herbicides should be used carefully. Individual plant treatments for brush species on rangeland are not a problem; however, broadcast herbicides should not be used during the growing season in habitat areas.

HABITAT

Navasota ladies-tresses is endemic to the Oak Woodlands and Prairies region of east-central Texas. They occur primarily in seasonally moist soils along open wooded margins of creeks, drainages, and intermittent tributaries of the Brazos and Navasota Rivers. Navasota ladies'-tresses is thought to require small-scale, patchy natural disturbances that provide canopy openings necessary to maintain habitat.

DISTRIBUTION

When Navasota ladies'-tresses was listed as endangered, only two populations were known, both in Brazos County. Once thought to be extremely rare, it is now known to be locally common in parts of its range. Since 1982, many more populations have been discovered in Brazos, Burleson, Fayette, Freestone, Grimes, Jasper, Leon, Madison, Milam, Robertson, and Washington Counties.

OTHER

Navasota ladies'-tresses was listed as endangered by the U.S. Fish and Wildlife Service (USFWS) in May 1982, and listed as endangered by the State of Texas soon afterwards. Landowners can help protect this rare and beautiful orchid by learning more about Navasota ladies'-tresses and its habitat requirements. If you think you may have this plant on your property and would like help in identifying it, contact your local Natural Resources Conservation Service office for assistance.

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Piping Plover (*Charadrius melodus)*

TPWD ©

Texas Status

Threatened

U.S. Status

Threatened, Listed 1/10/1986

Description

The piping plover is a small shore bird, about 7 1/4 inches long with a 15 inch wingspan. Distinguishing characteristics include sandy-colored feathers with grayish-brown crowns and backs, white foreheads, and dark bands across their crowns. Dark, but incomplete rings encircle their necks. These little birds have yellow-orange legs, black bands across their foreheads from eye to eye, and black rings around the base of their necks. They are small, stocky, sandy-colored birds that resemble sandpipers, with short, stubby bills.

Life History

Piping plovers reach sexual maturity at one year, and mate from late March through April. Males compete against each other for females' attention. They perform elaborate flights, and then scrape nests in the sand, tossing shells and small stones and twigs into them with their beaks. To create a nest, they scrape a shallow depression in the sand about 1 by 2.5 inches (2.5 by 6 cm). After their nests are built, they stand beside them with their wings partially spread and tails fanned. The males repeat this behavior until a female indicates interest. Once he has her attention, he begins a high-stepping "dance," continuing the courtship ritual. Females will lay about four gray to pale sand-colored eggs with a few dark spots. After an incubation period of 25 days, the young hatch within four to eight hours of each other, and fledge 30 to 35 days later. Although both sexes share responsibility for incubating the eggs, females commonly leave the young when the hatchlings are 14 to 20 days old. Males often remain with them until they can fly.

The chicks can move freely from their nests within hours of drying off. When predators or intruders come close, the young squat motionless on the sand while the parents attempt to attract the attention of the intruders to themselves, often by feigning a broken wing. Gulls, crows, raccoons, foxes and skunks are threats to the eggs and falcons may prey on the adult birds. The young plovers and adult plovers generally return to the same nesting area year after year. Plovers often run short distances, pausing to stare at the ground with a slightly tilted head, before picking a food item from the sand. When not feeding, plovers rest and preen.

There are just over 5,000 known pairs of breeding piping plovers. Texas is the wintering home for 35 percent of the known population of piping plovers. They begin arriving in late July or early August, and will remain for up to nine months. The piping plover's diet includes marine worms, beetles, spiders, crustaceans, mollusks and other small marine animals. Their life span is less than five years, but on occasion, up to 14 years.

HABITAT

These shorebirds live on sandy beaches and lakeshores.

DISTRIBUTION

Piping plovers migrate through the Great Lakes along the river systems through the Bahamas and West Indies. They are currently found along the Atlantic Coast from Canada to North Carolina and along the shorelines of Lakes Michigan and Superior. Gulf Coast beaches from Florida to Mexico, and Atlantic coast beaches from Florida to North Carolina provide winter homes for plovers.

THREATS AND REASONS FOR DECLINE

Habitat alteration and destruction are the primary causes for the decline of the Piping Plover. Loss of sandy beaches and lakeshores due to recreational, residential, and commercial development has reduced available habitat on the Great Lakes, Atlantic Coast, and the Gulf of Mexico. Reservoir construction, channel excavation, and modification of river flows have eliminated sandbar nesting habitat along hundreds of miles of the Missouri and Platte Rivers. Winter habitats along the Gulf coast are threatened by industrial and urban expansion and maintenance activities for commercial waterways. Pollution from spills of petrochemical products and other hazardous materials is also a concern.

On the breeding grounds, reproductive success can be curtailed by human disturbance. Vehicular and foot traffic destroys eggs and chicks. The presence of people on beaches and sandbar islands inhibits incubation and other breeding behavior. Changes in land use such as agricultural development, urbanization, and use of beaches has brought an increase in the number of unleashed pets and other predators such as gulls, skunks, and foxes.

Increased recreational use of Gulf beaches may also threaten the quality of wintering sites. Beach traffic, including vehicles and ATV's, as well as the activities of unleashed dogs, can disturb birds and degrade habitat. Beach raking, a practice associated with high recreational use, removes driftwood, seaweed, and other debris used by roosting plovers, and may disrupt nutrient cycles and remove prey organisms from foraging areas where plovers forage on the beach.

In 2001, the total population of Piping Plovers in North America was estimated to be 5,945 breeding adults. The Texas Gulf Coast had the highest wintering population, with about 1,042 individuals detected. This represents about 44% of birds detected on the wintering grounds during the 2001 International Piping Plover Census. Most of the plovers that winter on the Texas coast are found in the lower Laguna Madre, where tidal flats are extensive and productive. It is up to Texans to insure that the wintering habitat so vital to the survival of this species is protected.

Ongoing Recovery

State, federal, and private organizations are collaborating to monitor Piping Plover populations and assess current and potential habitat on breeding and wintering grounds. Research concerning reproductive success, food habits, habitat selection, and limiting factors is underway. The results of these studies will help biologists develop management plans designed to benefit Piping Plovers. Protective measures, such as signs or fences, are being implemented to reduce human disturbance to breeding birds. Vegetation management, predator control, pollution abatement, and habitat creation/restoration are management strategies being used to benefit Piping Plover populations. Biologists continue to assess habitat availability and quality throughout the plover's range in Texas, and identify essential habitat for management and protection. Finally, public information campaigns concerning Piping Plover conservation are a vital part of the recovery process.

Critical habitat was designated for wintering Piping Plovers in July of 2001. This designation identifies areas that are important to the plovers on their wintering grounds, and provides the public and resource agencies with information that can be used to minimize impacts to these areas.

How You Can Help

Whether you enjoy fishing, boating, swimming, or viewing wildlife, please remember that your actions, especially when multiplied by thousands of other recreational users, can have an immense impact on the bays and estuaries of the Texas Coast. Responsible recreational use should include proper disposal of trash and other potential pollutants, respect for private property rights, preventing harm to plants and wildlife, and generally keeping human impacts to a minimum. Minimize driving on the beach and keep pets on a leash. Extensive driving on tidal flats on the bayside of barrier islands should also be minimized, as significant rutting can alter the habitat required by these birds. Avoid disturbance to foraging shorebirds to the greatest extent possible.

You can be involved in the conservation of Texas' nongame wildlife resources by supporting the Special Nongame and Endangered Species Conservation Fund. Special nongame stamps are available at Texas Parks and Wildlife Department (TPWD) field offices, most state parks, and the License Branch of TPWD headquarters in Austin. Conservation organizations in Texas also welcome your participation and support.

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Large-fruited Sand-verbena (*Abronia macrocarpa)*

TPWD ©

Texas Status

Endangered

U.S. Status

Endangered, Listed 9/28/1988

Description

The large-fruited sand-verbena has stems up to 20 inches tall covered with sticky hairs. It has round clusters of pink-purple flowers up to 4 inches across.

Life History

Rosettes appear in the fall, and the plant flowers from March through June. The flowers open late in the afternoon, and have a sweet odor that increases toward evening. At night, moths help this plant reproduce by spreading pollen from plant to plant. Yaupon and grape are plants which provide food for the moth larvae, so the presence of these food plants in the habitat is important. The entire above-ground portion of the plant dies back during the heat of the summer.

The large-fruited sand-verbena is endangered because many areas of sandy soils have been cleared of native vegetation and planted to pasture grasses. Construction of housing developments and oil wells has also destroyed or changed its habitat (open areas of deep sandy soil).

Habitat

It lives in sandy openings in post oak woods.

Distribution

This plant is distributed in Leon, Robertson, and Freestone Counties.

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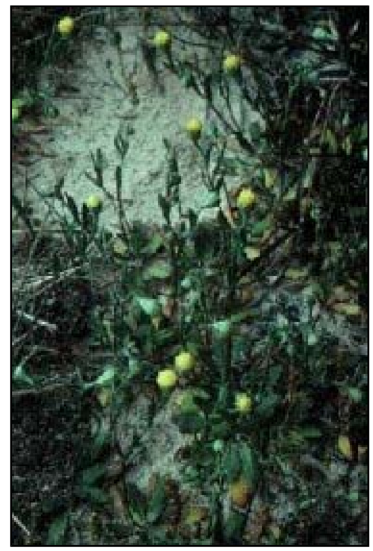
Texas Prairie Dawn (*Hymenoxys texana*)



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Other Names

Prairiedawn, Texas Bitterweed, Texas Prairie Dawn-flower

Texas Status

Endangered

U.S. Status

Endangered, Listed 3/13/1985

Description

Texas Prairie Dawn is a delicate annual one to six inches tall. Despite being one of the state's smallest sunflowers, Texas prairie dawn is not easily overlooked. Its yellow flower heads, less than 1/2 inch in diameter, stand out brightly in the patches of dull gray barren sand in which the species is normally found.

Life History

Because this suitable habitat is limited to such a small geographic area, Texas prairie dawn was not encountered by botanists for almost 100 years after its original discovery, and was thought to be extinct. It flowers in March - early April; disappearing by mid-summer. The status of Texas prairie dawn is better known today, and much of its remaining habitat is protected on public lands administered by the U. S. Army Corps of Engineers. It is known from about 50 sites, many within Addicks and Barker Reservoirs in western Harris County. However, habitat destruction by urban development continues to threaten this tiny plant.

Habitat

It grows in sparsely vegetated areas ("slick spots") at the base of mima mounds ("pimple mounds") or other nearly barren areas on slightly saline soils in coastal prairie grasslands.

Distribution

This wildflower is found in Fort Bend and Harris counties, southeast Texas.

Other

This species occurs within and on the outskirts of Houston.

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Timber Rattlesnake (*Crotalus horridus)*

OTHER NAMES

Canebrake Rattlesnake

TEXAS STATUS

Threatened

DESCRIPTION

Timber rattlesnakes have wide heads and narrow necks—a typical distinction of all venomous snakes except coral snakes *(Micrurus fulvius)*. Timber rattlers are the second largest venomous snake in Texas and third largest in the United States. Adult timber rattlesnakes reach a length of 36 to 40 inches (91 to 101 cm), and weigh 1.3 to 2 pounds (0.58 to 0.9 kg). They have a heavy, light yellow, gray or greenish-white body with a rust-colored strip along the length of their bac and a black tail is tipped with rattles. Timber rattlesnakes have yellow eyes with elliptical or cat-like pupils. Twenty to 29 dark, V-shaped crossbars with jagged edges form a distinctive pattern across their back.

LIFE HISTORY

Rabbits, squirrels, rats, mice and occasionally birds, other snakes, lizards, and frogs are the timber rattlesnake's prey. Coyotes, bobcats, skunks, foxes, hawks and owls, and snake-eating snakes such as king snakes, indigo snakes and cottonmouths feed on timber rattlesnakes. Sexual maturity is reached at three years for males and up to four years for females. Mating season is in early spring; only once every two to three years for females.

Timber rattlers, like other pit vipers, do not lay eggs. Instead the eggs are kept inside the female's body until they are ready to "hatch." The egg have an estimated incubation time of six months. Litters consist of between five and 20 young, which are 10 to 17 inches long (25 to 43 cm). Young may remain near their mother for seven to ten days after birth, but no parental care is provided. Timber rattlesnakes live up to ten years.

Although diurnal (active during the day) during spring and fall, timber rattlesnakes become nocturnal (active at night) during the oppressive heat of the summer. They will coil beside a fallen tree or log and wait for their quick-moving prey to pass. Pit vipers can develop an appetite for certain prey—some spend their lives eating only birds or chipmunks while others will eat a variety of foods. Their interest and appetite seems to be shaped by killing a particular prey early in life.

Highly venomous, timber rattlesnakes are sometimes slow to defend themselves and rely on their ability to blend into their surroundings to avoid confrontation. They seek to escape rather than risking danger and will remain silent, and if possible, will hide before revealing their position to a predator. Despite their large size and reputation, they are difficult to provoke into rattling or biting. Still, it does happen. It is best not to take any chances with such a potentially deadly snake. If one is bitten, seek immediate medical attention.

According to popular belief, one can tell the age of a rattlesnake by the number of rattles present at the end of its tail. A baby rattlesnake is born with the first segment of its rattle, called a "button". As the snake grows (and with each molting of its outer skin) an additional segment is added to its rattle. Younger snakes shed more often than older snakes, but on average, free-ranging snakes may molt three to six times a year. Another clue to a snake's age is its color: timber rattlers darken as they age, and the darkest are old males. The scientific name, Crotalus horridus, is formed from two Latin words: crotalum, meaning "bell or rattle," and horridus, for "dreadful"—which makes reference to its venom.

Habitat

Timber rattlesnakes prefer moist lowland forests and hilly woodlands or thickets near permanent water sources such as rivers, lakes, ponds, streams and swamps where tree stumps, logs and branches provide refuge.

Distribution

Timber rattlesnakes are found in upland woods and rocky ridges in the eastern United States; the eastern third of Texas.

Other

Although many timber rattlers meet their deaths at the hands of people or by automobiles, the fastest way to kill timber rattlesnake populations is by destroying or altering the places they need to hunt, hibernate and live. Today, every state inhabited by timber rattlesnakes has laws protecting the species, including Texas. In Texas, it is listed as a threatened species. This means that people cannot take, transport, have in their possession or sell timber rattlesnakes.

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White-faced Ibis (*Plegadis chihi)*

Texas Status

Threatened

Description

The white-faced ibis is a dark, chestnut colored-bird with green or purple on its head and upper parts, and a long, down-curved bill. It is very similar in appearance to the glossy ibis except during the breeding season when the white-faced ibis has a narrow border of white feathers all around its bare facial skin at the base of the bill. This ibis has reddish legs and feet and red bare skin on the face around the eyes.

Life History

The white-faced ibis seems to prefer freshwater marshes, where it can find insects, newts, leeches, earthworms, snails and especially crayfish, frogs and fish. They roost on low platforms of dead reed stems or on mud banks.

During the nesting season, they are colonial and will construct a deep cup of dead reeds among beds of bulrushes, on floating mats of dead plants or they may nest in trees. The areas where these nests are built usually are where water is less than three feet deep. The nests are lined with grasses in preparation for the ibis nestlings. In Texas, between April and June, three to four greenish-blue eggs will hatch after an incubation period of approximately 21 to 22 days. The male and female both share in the parenting responsibilities of incubation and brooding of the nestlings. Nestlings initially are covered with a dull, blackish down and are noted to be uncommonly timid.

Habitat

The white-faced ibis frequents marshes, swamps, ponds and rivers.

Distribution

It nests in isolated colonies from Oregon to Kansas, but its center of greatest abundance seems to be in Utah, Texas and Louisiana. In Texas, they breed and winter along the Gulf Coast and may occur as migrants in the Panhandle and West Texas.

Other

White-faced ibises are declining throughout North America, where continuing threats include draining of wetlands and the widespread use of pesticides. They currently are listed as state threatened. The federal government is awaiting additional information on them before deciding if they should be given federal status as an endangered or threatened species.

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Whooping Crane (*Grus americana)*

Photo ©TPWD

Texas Status

Endangered

U.S. Status

Endangered, Listed 6/02/1970

Description

At nearly 5 feet (1.5 m) tall, whooping cranes are the tallest birds in North America. They have a wingspan of 7.5 feet (2.3 m). Whooping cranes are white with rust-colored patches on top and back of head, lack feathers on both sides of the head, yellow eyes, and long, black legs and bills. Their primary wing feathers are black but are visible only in flight.

Life History

The tallest bird in North America, the whooping crane breeds in the wetlands of Wood Buffalo National Park in northern Canada and spends the winter on the Texas coast at Aransas National Wildlife Refuge near Rockport. Whooping cranes begin their fall migration south to Texas in mid-September and begin the spring migration north to Canada in late March or early April. Whooping cranes migrate more than 2,400 miles a year. As many as 1,400 whooping cranes migrated across North America in the mid-1800s. By the late 1930s, the Aransas population was down to just 18 birds. Because of well-coordinated efforts to protect habitat and the birds themselves, the population is slowly increasing. In 1993, the population stood at 112. In the spring of 2002, it is estimated that there were 173 whoopers - a small, but important increase. Today, three populations exist: one in the Kissimmee Prairie of Florida, the only migratory population at Aransas National Wildlife Refuge, and a very small captive-bred population in Wisconsin.

Whooping cranes mate for life, but will accept a new mate if one dies. These long-lived birds cranes can live up to 24 years in the wild. The mated pair shares brooding duties; either the male or the female is always on the nest. Generally, one chick survives. It can leave the nest while quite young, but is still protected and fed by its parents. Chicks are rust-colored when they hatch; at about four months, chicks' feathers begin turning white. By the end of their first migration, they are brown and white, and as they enter their first spring, their plumage is white with black wing tips.

The hatchlings will stay with their parents throughout their first winter, and separate when the spring migration begins. The sub-adults form groups and travel together. Cranes live in family groups made up of the parents and 1 or 2 offspring. In the spring, whooping cranes perform courtship displays (loud calling, wing flapping, leaps in the air) as they get ready to migrate to their breeding grounds. Their diet consists of blue crabs, clams, frogs, minnows, rodents, small birds, and berries. Early 1999 counts showed 183 birds left the wintering grounds on the Texas coast (with smaller populations in New Mexico and Florida).

HABITAT

Whooping cranes winter on the Aransas National Wildlife Refuge's 22,500 acres of salt flats and marshes. The area's coastal prairie rolls gently here and is dotted with swales and ponds. They summer and nest in poorly drained wetlands in Canada's Northwest Territories at Wood Buffalo National Park.

DISTRIBUTION

Although they breed in Canada during the summer months, whooping cranes migrate to Texas' coastal plains near Rockport, in and around Aransas National Wildlife Refuge, from November through March.

How you can help:

Whooping cranes migrate throughout the central portion of the state from the eastern panhandle to the DFW area and south through the Austin area to the central coast during October-November and again in April. If you sight a whooping crane during migration or away from the coast during the winter, then please contact the Wildlife Diversity Program at 1-800-792-1112 x4644 or mark.klym@tpwd.state.tx.us.

OTHER

Whooping cranes are one of the rarest bird species in North America. Whooping cranes are protected in Canada, the United States and Mexico. Because some of their habitat is federally protected, the land is managed to preserve the animals. The greatest threats to whooping cranes are man-made: power lines, illegal hunting, and habitat loss. Because the Gulf International Waterway goes through their habitat area, the cranes are susceptible to chemical spills and other petroleum-related contamination. Public awareness and support are critical to whooping cranes' survival as a species.

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Endangered and Threatened Species Links:

- Mammals
- Fish
- Reptiles and Amphibians
- Plants
- Birds
- Invertebrates

Additional Links

- Federal Endangered Species Act
- Texas Threatened and Endangered Species Regulations
- Rare, Threatened, and Endangered Species of Texas by County
- Map of Texas Ecoregions
  - Natural Subregions of Texas (PDF 198.6 KB)
  - Natural Subregions of Texas (JPG, 147.8 KB)
- Rare Resources Review Requests (Including Threatened and Endangered Species) (PDF 263.3 KB)
- Rare Resources Review Requests (Including Threatened and Endangered Species) (Word 137.5 KB)

East Texas Black Bear:

Conservation and Management Plan

Louisiana Black Bear *(Ursus americanus luteolus)*

Date of Listing: Threatened, 1992

© Photo S. C. Amstrup, USFWS

Louisiana Black Bears are active from April to November. After emerging from dens in spring, bears may initially be in a "semi-fasting" state as they continue to utilize remaining winter fat reserves. At this time they eat succulent, easy-to-digest vegetation. During the summer they eat mostly berries, insects, and carrion. In order to gain weight for the winter, bears eat nuts such as acorns and pecans which are high in carbohydrates and fats. They hibernate in the winter in large hollow trees, downed logs, or in ground nests which are shallow depressions lined with vegetation. Denning bears exhibit varying degrees of awareness, but most can easily be roused if disturbed.

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Reason for Concern:

Habitat loss has been the main reason for the bear's decline. Reservoir construction has flooded many miles of former bottomland hardwood habitat. In addition, many bottomlands forests have been cut and converted to agricultural areas or housing developments. Today, efforts are being made to restore the Louisiana black bear to its former range in areas with suitable habitat.

Additional information:

East Texas Black Bear Conservation and Management Plan, 2005 - 2015

Size:

120-400 lbs; 4.5-6.5 feet long; adult males are larger than adult females

Diet:

Acorns, pecans, berries, persimmon fruits, palmetto, insects, carrion

Habitat (where it lives):

Primarily in bottomland hardwoods and floodplain forests, but also upland hardwoods, mixed pine/hardwoods, coastal flatwoods, and marshes

Range (where found in Texas):

East Texas, Louisiana, and Mississippi

Life Span:

Up to 30 years

Reproduction:

Litter sizes range from 1 to 3 cubs; females have a litter every other winter while denning, and the young cubs usually spend their first 1.5 to 2 years with their mother before dispersing

Population Numbers:

Improving

Interesting Fact:

Although not true hibernators, bears generally do not eat, drink, urinate or defecate in winter. They have a unique metabolic process to recycle waste products during winter dormancy.

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Exotic Aquatics Links

- List of Invasive, Prohibited and Exotic Species
- Invasives Choke Texas
- Protect Our Waters
- The Snakehead Threat
- Nuisance Aquatic Vegetation
- Grass Carp Permit Program
- USGS Exotics Database
- National Clearinghouse on Invasive Species

Related Information:

- Complete regulations on Potentially Harmful Fish, Shellfish and Aquatic Plants - Texas Administrative Code, Title 31, Part 2, Chapter 57, Subchapter A

Invasive, Prohibited and Exotic Species

The organisms listed on this page are legally classified as exotic, harmful, or potentially harmful. No person may import, possess, sell, or place them into water of this state except as authorized by rule or permit issued by the department. For more information, contact Joedy Gray, (512) 389-8037.

Fish | Shellfish | Aquatic Plants

Fish

Lampreys, Family Petromyzontidae
All species except *Ichthyomyzon castaneus* and *I. gagei*

Freshwater Stingrays, Family Potamotrygonidae
All species

Arapaima, Family Osteoglossidae
Arapaima gigas

South American Pike Characoids, Family Characidae
All species of genus *Acestrorhyncus*

African Tiger Fishes, Family, Subfamily Alestiidae: Hydrocyninae
All species of genus *Hydrocynus*

Piranhas and Pirambebas, Family Serrasalmideae, Subfamily Serrasalminae
All species except pacus of the genus *Piaractus*

Payara and other wolf or vampire tetras, Family Characidae, Subfamily Rhaphiodontinae
All species of genera *Hydrolycus* and *Rhaphiodon*, including *Cynodon*

Dourados, Family Characidae, Subfamily Bryconinae
All species of genus *Salminus*

South American Tiger Fishes, Family Erythrinidae
All species

South American Pike Characoids, Family Ctenolucidae
All species of genera *Ctenolucius* and *Boulengerella*, including *Luciocharax* and *Hydrocinus*

African Pike Characoids, Families Hepsetidae and Ichthyboridae
All species

Electric Eels, Family Electrophoridae

Electrophorus electricus

Carps and Minnows, Family Cyprinidae

All species and hybrids of species of genera:
Aspius, Pseudoaspius, Aspiolucius (Asps);
Abramis, Blicca, Megalobrama, Parabramis (Old World Breams);
Hypophthalmichthys or *Aristichthys* (Bighead Carp);
Mylopharyngodon (Black Carp);
Ctenopharyngodon (Grass Carp);
Cirrhinus (Mud Carp);
Thynnichthys (Sandkhol Carp);
Hypophthalmichthys (Silver Carp);
Catla (Catla);
Leuciscus (Old World Chubs, Ide, Orfe, Daces);
Tor, including the species *Barbus hexiglonolepsis* (Giant Barbs and Mahseers);
Rutilus (Roaches);
Scardinius (Rudds);
Elopichthys (Yellowcheek);
Catlocarpio (Giant Siamese Carp);
All species of the genus *Labeo* (Labeos) except *Labeo chrysophekadion* (Black SharkMinnow)

Walking Catfishes, Family Clariidae

All species

Electric Catfishes, Family Malapteruridae

All species

South American Parasitic Candiru Catfishes, Subfamilies Stegophilinae and Vandelliinae

All species

Pike Killifish, Family Poeciliidae

Belonesox belizanus

Marine Stonefishes, Family Synanceiidae

All species

Tilapia, Family Cichlidae

All species of genera *Tilapia*, *Oreochromis* and *Saratherodon*

Asian Pikeheads, Family Luciocephalidae

All species

Snakeheads, Family Channidae

All species
Learn more about snakeheads

Old World Pike-Perches, Family Percidae

All species of the genus *Sander* except *Sander vitreum*

Nile Perch, Family Centropomidae (also called Latidae)

All species of genera *Lates* and *Luciolates*

Seatrouts and Corvinas, Family Sciaenidae

All species of genus *Cynoscion* except *Cynoscion nebulosus*, *C. nothus*, and *C. arenarius*

Whale Catfishes, Family Cetopsidae
All species

Ruffe, Family Percidae
All species of genus *Gymnocephalus*

Air sac Catfishes, Family Heteropneustidae
All species

Swamp Eels, Rice Eels or One-Gilled Eel, Family Synbranchidae
All species

Freshwater Eels, Family Anguilliidae
All species except *Anguilla rostrata*

Round Gobies, Family Gobiidae
All species of genus *Neogobius*, including *N. melanostoma*

Temperate Basses, Family Moronidae
All species except for *Morone saxatilis*, *M. chrysops* and *M. mississippiensis* and hybrids between these three species

Temperate Perches, Family Percichthyidae
All species, including species of the genus *Siniperca* (Chinese perches)

Shellfish

Crayfishes, Family Parastacidae
All species

Mittencrabs, Family Grapsidae
All species of genus *Eriocheir*

Applesnails and Giant Ram's-horn Snails
All genera and species of the Family Ampullariidae (previously called Pilidae) including *Pomacea* and *Marisa*, except spiketop applesnail *(Pomacea bridgesii)*

Zebra Mussels, Family Dreissenidae
All species of genus *Dreissena*

Penaeid Shrimp, Family Penaeidae
All species of genera *Penaeus*, *Litopenaeus*, *Farfantepenaeus*, *Fenneropenaeus*, *Marsupenaeus*, and *Melicertus* (all previously considered Penaeus) except *L. setiferus*, *Far. aztecus* and *Far. duorarum*

Oysters, Family Ostreidae
All species except *Crassostrea virginica* and *Ostrea equestris*

Aquatic Plants

Giant or Dotted Duckweed, Family Lemnaceae
Landolita punctata

Salvinia, Family Salviniaceae
All species of genus *Salvinia*, including *Salvinia molesta* **(giant salvinia)**

Learn more about invasive aquatic plants

Waterhyacinths, Family Pontederiaceae
Eichhornia crassipes (floating waterhyacinth) and *Eichhornia azurea* (rooted waterhyacinth)

Waterlettuce, Family Araceae
Pistia stratiotes

Hydrilla, Family Hydrocharitaceae
Hydrilla verticillata

Lagarosiphon, Family Hydrocharitaceae
Lagarosiphon major

Eurasian Watermilfoil, Family Haloragaceae
Myriophyllum spicatum

Alligatorweed, Family Amaranthaceae
Alternanthera philoxeroides

Paperbark, Family Myrtaceae
Melaleuca quinquenervia

Torpedograss, Family Gramineae
Panicum repens

Water Spinach, Family Convolvulaceae
Ipomoea aquatica (also called ong choy, rau mong and kangkong)

Ambulia
Limnophila sessiflora

Narrowleaf False Pickerelweed
Monochoria hastata

Heartshaped False Pickerelweed
Monochoria vaginalis

Duck-lettuce
Ottelia alismoides

Wetland Nightshade
Solanum tampicense

Exotic Bur-reed
Sparganium erectum

Brazilian Peppertree
Schinus terebinthifolius

Purple Loosestrife
Lythrum salicaria

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Species Search Results for 'Fannin'

Taxon	Common Name	Scientific Name	Federal Status	State Status	County Range
Birds	Henslow's Sparrow	Ammodramus henslowii			View Map
Birds	Piping Plover	Charadrius melodus	LT	T	View Map
Birds	Cerulean Warbler	Dendroica cerulea			View Map
Birds	Peregrine Falcon	Falco peregrinus	DL	T	View Map
Birds	American Peregrine Falcon	Falco peregrinus anatum	DL	T	View Map
Birds	Arctic Peregrine Falcon	Falco peregrinus tundrius	DL		View Map
Birds	Whooping Crane	Grus americana	LE	E	View Map
Birds	Bald Eagle	Haliaeetus leucocephalus	DL	T	View Map
Birds	Wood Stork	Mycteria americana		T	View Map
Birds	Eskimo Curlew	Numenius borealis	LE	E	View Map
Birds	Interior Least Tern	Sterna antillarum athalassos	LE	E	View Map
Fishes	Western sand darter	Ammocrypta clara			View Map
Fishes	Blue sucker	Cycleptus elongatus		T	View Map
Fishes	Creek chubsucker	Erimyzon oblongus		T	View Map
Fishes	Orangebelly darter	Etheostoma radiosum			View Map
Fishes	Goldeye	Hiodon alosoides			View Map
Fishes	Taillight shiner	Notropis maculatus			View Map
Fishes	Blackside darter	Percina maculata		T	View Map
Fishes	Paddlefish	Polyodon spathula		T	View Map
Fishes	Shovelnose sturgeon	Scaphirhynchus platorynchus		T	View Map
Insects	American burying beetle	Nicrophorus americanus	LE		View Map
Mammals	Red wolf	Canis rufus	LE	E	View Map
Mammals	Plains spotted skunk	Spilogale putorius interrupta			View Map
Mammals	Black bear	Ursus americanus	T/SA;NL	T	View Map
Mollusks	Rock pocketbook	Arcidens confragosus			View Map
Mollusks	Wabash pigtoe	Fusconaia flava			View Map
Mollusks	Plain pocketbook	Lampsilis cardium			View Map

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Species Search Results for 'Austin'

Taxon	Common Name	Scientific Name	Federal Status	State Status	County Range
Amphibians	Houston toad	Bufo houstonensis	LE	E	View Map
Birds	Henslow's Sparrow	Ammodramus henslowii			View Map
Birds	Western Burrowing Owl	Athene cunicularia hypugaea			View Map
Birds	White-tailed Hawk	Buteo albicaudatus		T	View Map
Birds	Mountain Plover	Charadrius montanus			View Map
Birds	Peregrine Falcon	Falco peregrinus	DL	T	View Map
Birds	American Peregrine Falcon	Falco peregrinus anatum	DL	T	View Map
Birds	Arctic Peregrine Falcon	Falco peregrinus tundrius	DL		View Map
Birds	Whooping Crane	Grus americana	LE	E	View Map
Birds	Bald Eagle	Haliaeetus leucocephalus	DL	T	View Map
Birds	Wood Stork	Mycteria americana		T	View Map
Birds	White-faced Ibis	Plegadis chihi		T	View Map
Birds	Interior Least Tern	Sterna antillarum athalassos	LE	E	View Map
Birds	Attwater's Greater Prairie-Chicken	Tympanuchus cupido attwateri	LE	E	View Map
Fishes	Sharpnose shiner	Notropis oxyrhynchus	C		View Map
Insects	A mayfly	Pseudocentroptiloides morihari			View Map
Mammals	Red wolf	Canis rufus	LE	E	View Map
Mammals	Plains spotted skunk	Spilogale putorius interrupta			View Map
Mammals	Louisiana black bear	Ursus americanus luteolus	LT	T	View Map
Mollusks	Rock pocketbook	Arcidens confragosus			View Map
Mollusks	Smooth pimpleback	Quadrula houstonensis		T	View Map
Mollusks	False spike mussel	Quincuncina mitchelli		T	View Map
Mollusks	Pistolgrip	Tritogonia verrucosa			View Map
Mollusks	Texas fawnsfoot	Truncilla macrodon		T	View Map
Plants	Shinner's sunflower	Helianthus occidentalis ssp plantagineus			View Map
Plants	Texas meadow-rue	Thalictrum texanum			View Map
Reptiles	Timber/Canebrake rattlesnake	Crotalus horridus		T	View Map

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Species Search Results for 'Freestone'

Taxon	Common Name	Scientific Name	Federal Status	State Status	County Range
Amphibians	Houston toad	Bufo houstonensis	LE	E	View Map
Birds	Bachman's Sparrow	Aimophila aestivalis		T	View Map
Birds	Henslow's Sparrow	Ammodramus henslowii			View Map
Birds	Piping Plover	Charadrius melodus	LT	T	View Map
Birds	Peregrine Falcon	Falco peregrinus	DL	T	View Map
Birds	American Peregrine Falcon	Falco peregrinus anatum	DL	T	View Map
Birds	Arctic Peregrine Falcon	Falco peregrinus tundrius	DL		View Map
Birds	Whooping Crane	Grus americana	LE	E	View Map
Birds	Bald Eagle	Haliaeetus leucocephalus	DL	T	View Map
Birds	Wood Stork	Mycteria americana		T	View Map
Birds	Interior Least Tern	Sterna antillarum athalassos	LE	E	View Map
Mammals	Red wolf	Canis rufus	LE	E	View Map
Mammals	Southeastern myotis bat	Myotis austroriparius			View Map
Mammals	Plains spotted skunk	Spilogale putorius interrupta			View Map
Mollusks	Rock pocketbook	Arcidens confragosus			View Map
Mollusks	Texas pigtoe	Fusconaia askewi		T	View Map
Mollusks	Wabash pigtoe	Fusconaia flava			View Map
Mollusks	Sandbank pocketbook	Lampsilis satura		T	View Map
Mollusks	Louisiana pigtoe	Pleurobema riddellii		T	View Map
Mollusks	Texas heelsplitter	Potamilus amphichaenus		T	View Map
Mollusks	Creeper (squawfoot)	Strophitus undulatus			View Map
Mollusks	Pistolgrip	Tritogonia verrucosa			View Map
Mollusks	Fawnsfoot	Truncilla donaciformis			View Map
Mollusks	Little spectaclecase	Villosa lienosa			View Map
Plants	Large-fruited sand-verbena	Abronia macrocarpa	LE	E	View Map
Plants	Navasota ladies'-tresses	Spiranthes parksii	LE	E	View Map
Plants	Rough-stem aster	Symphyotrichum puniceum var scabricaule			View Map

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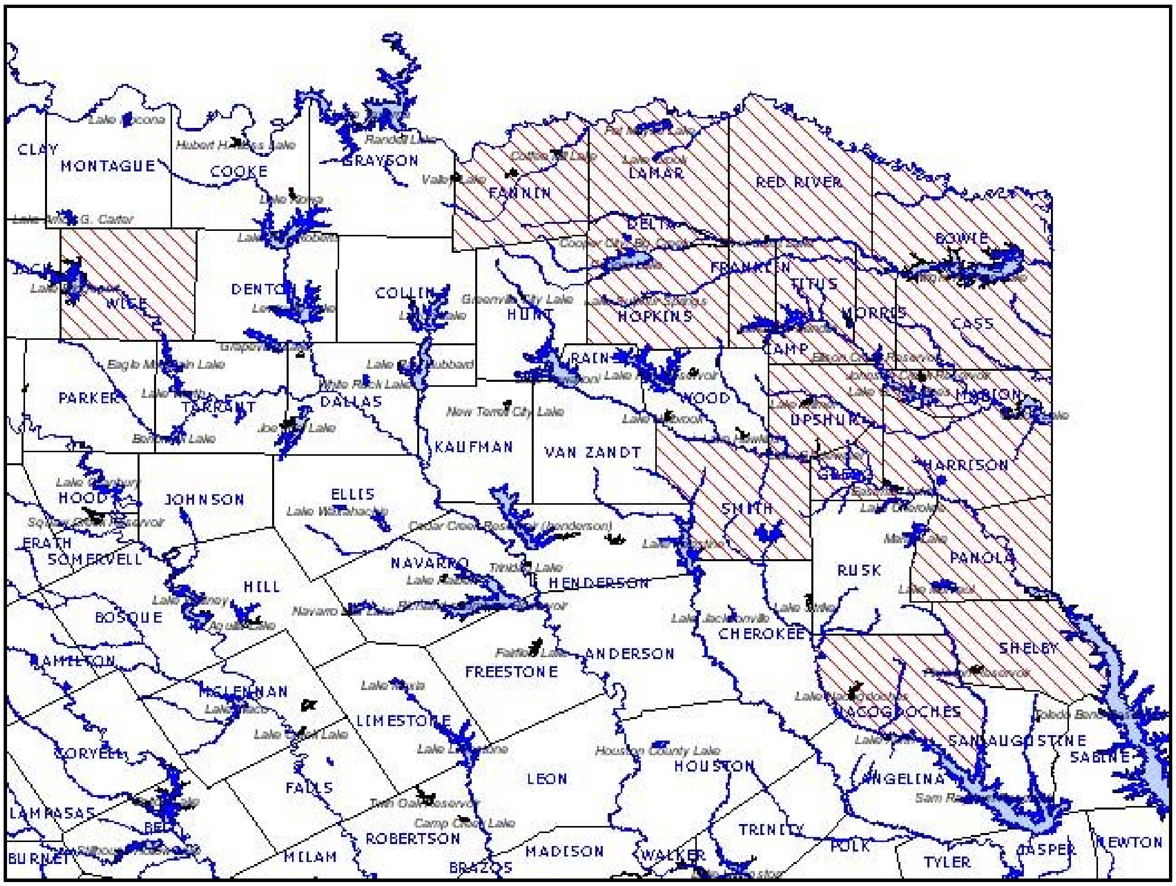
Blackside darter *Percina maculata*

Federal Status: **State Status: T**

Red, Sulfur and Cypress River basins; clear, gravelly streams; prefers pools with some current, or even quiet pools, to swift riffles

Revision Date: 07/16/2009

potential or known presence within county



Bowie, Camp, Cass, Delta, Fannin, Franklin, Gregg, Harrison, Hopkins, Lamar, Marion, Morris, Nacogdoches, Panola, Red River, Shelby, Smith, Titus, Upshur, Wise County(ies)

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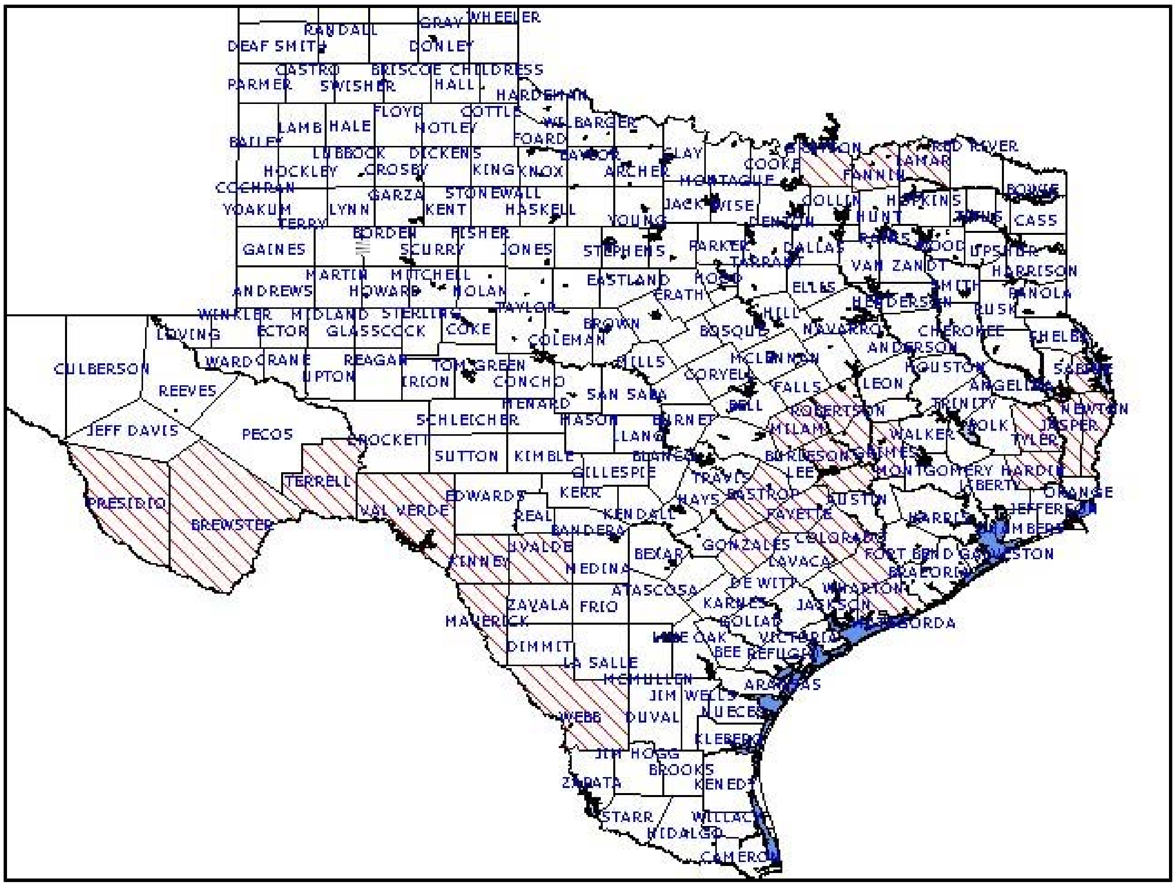
Blue sucker — *Cycleptus elongatus*

Federal Status: — **State Status: T**

larger portions of major rivers in Texas; usually in channels and flowing pools with a moderate current; bottom type usually of exposed bedrock, perhaps in combination with hard clay, sand, and gravel; adults winter in deep pools and move upstream in spring to spawn on riffles

Revision Date: 10/28/2009 — **potential or known presence within county**



Bastrop, Brazos, Brewster, Burleson, Caldwell, Colorado, Fannin, Fayette, Gonzales, Grayson, Grimes, Hardin, Jasper, Kinney, Lamar, Matagorda, Maverick, Milam, Newton, Presidio, Robertson, Sabine, Terrell, Tyler, Uvalde, Val Verde, Washington, Webb, Wharton County(ies)

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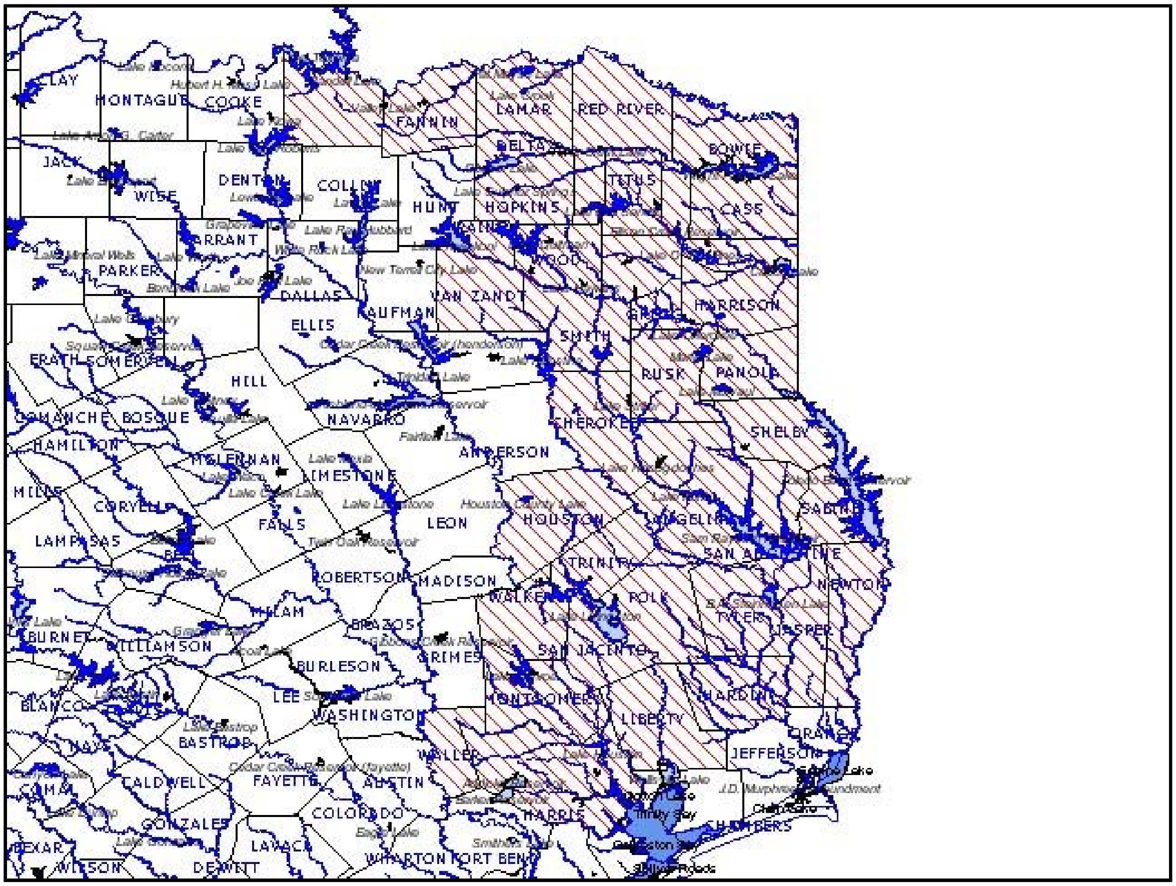
Creek chubsucker *Erimyzon oblongus*

Federal Status: **State Status: T**

tributaries of the Red, Sabine, Neches, Trinity, and San Jacinto rivers; small rivers and creeks of various types; seldom in impoundments; prefers headwaters, but seldom occurs in springs; young typically in headwater rivulets or marshes; spawns in river mouths or pools, riffles, lake outlets, upstream creeks

Revision Date: 07/18/2005

potential or known presence within county



Angelina, Bowie, Camp, Cass, Cherokee, Delta, Fannin, Franklin, Grayson, Gregg, Hardin, Harris, Harrison, Hopkins, Houston, Jasper, Lamar, Liberty, Marion, Montgomery, Morris, Nacogdoches, Newton, Panola, Polk, Rains, Red River, Rusk, Sabine, San Augustine, San Jacinto, Shelby, Smith, Titus, Trinity, Tyler, Upshur, Van Zandt, Walker, Waller, Wood County(ies)

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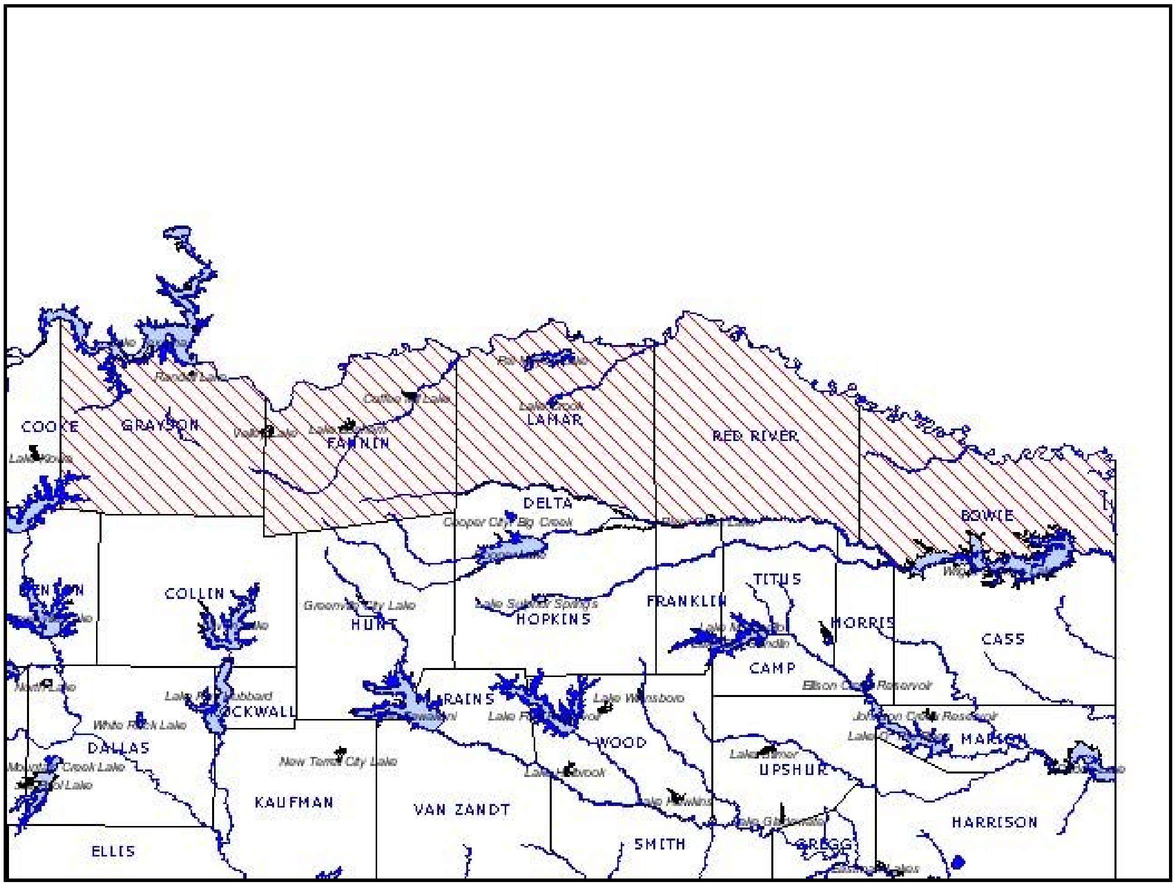
Goldeye	***Hiodon alosoides***
Federal Status:	**State Status:**

Red River basin below reservoir; spawns spring to July in shallow firm-bottomed backwaters or gravel shoals in tributaries, eggs semibuoyant drift downstream or to quiet water; adults in quiet turbid water of medium to large lowland rivers, small lakes, marshes and muddy shallows connected to them; young feed on microcrustaceans and other inverts; adults on surface water insects, also frogs, fishes, and small mammals

Revision Date: 07/15/2005 — **potential or known presence within county**



Bowie, Fannin, Grayson, Lamar, Red River County(ies)

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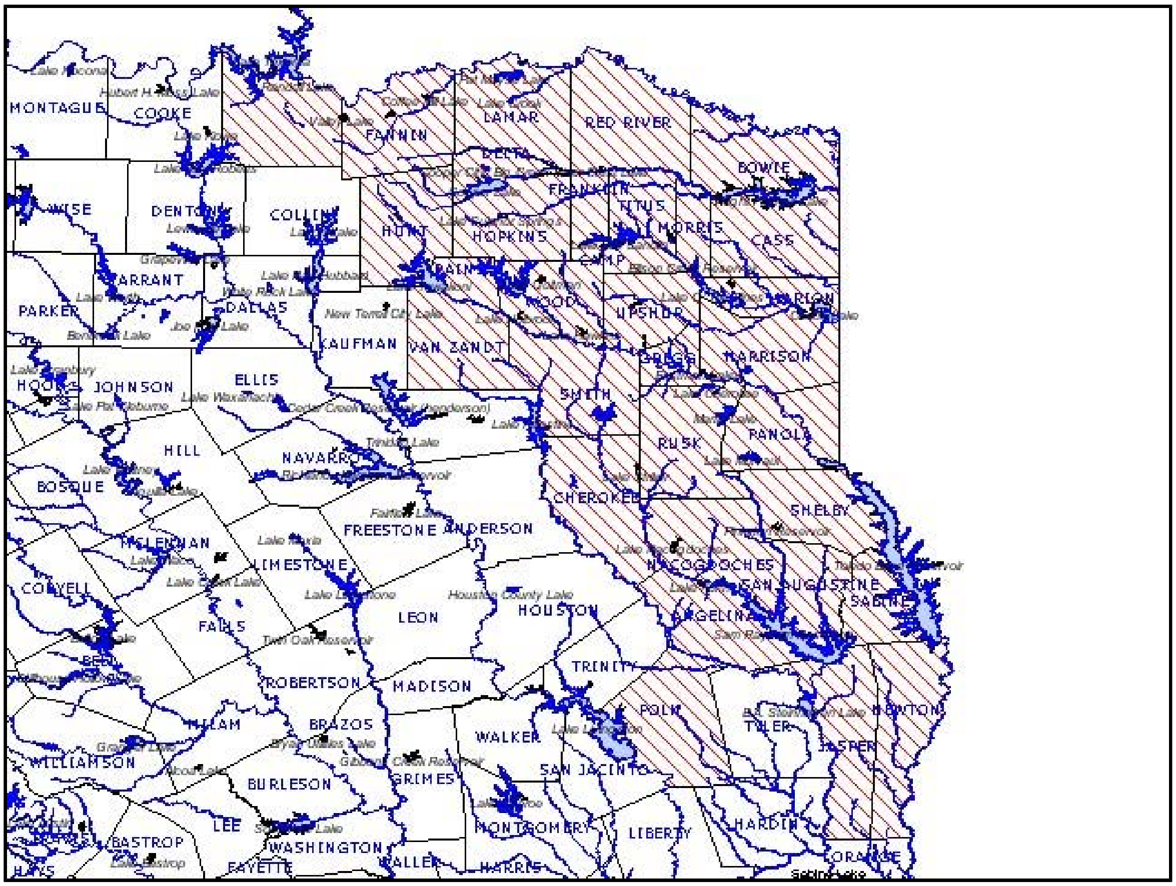
Orangebelly darter	***Etheostoma radiosum***
Federal Status:	**State Status:**

Red through Angelina River basins; just headwaters ranging from high gradient streams to more sluggish lowland streams, gravel and rubble riffles preferred; eggs buried in gravel and riffle raceways, post-larvae live in quiet water, move into progressively faster water as they mature, young feed mostly on copepods and cladocerans, adults on mayfly and fly larvae, spawn late February through mid-April in eastern Texas

Revision Date: 07/16/2009 — **potential or known presence within county**



Angelina, Bowie, Camp, Cass, Cherokee, Delta, Fannin, Franklin, Grayson, Gregg, Harrison, Hopkins, Hunt, Jasper, Lamar, Marion, Morris, Nacogdoches, Newton, Panola, Polk, Rains, Red River, Rusk, Sabine, San Augustine, Shelby, Smith, Titus, Upshur, Van Zandt, Wood County(ies)

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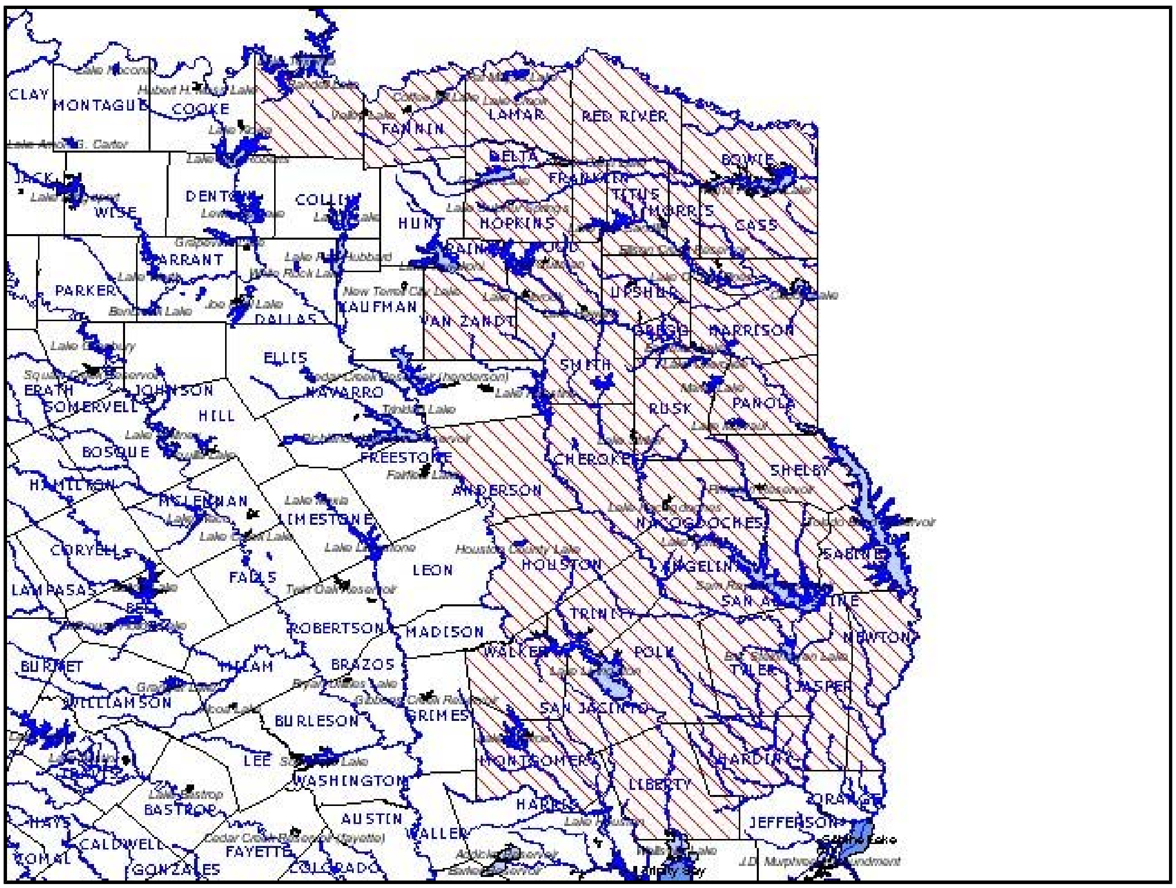
Paddlefish *Polyodon spathula*

Federal Status: **State Status: T**

prefers large, free-flowing rivers, but will frequent impoundments with access to spawning sites; spawns in fast, shallow water over gravel bars; larvae may drift from reservoir to reservoir

Revision Date: 07/16/2009

potential or known presence within county



Anderson, Angelina, Bowie, Camp, Cass, Cherokee, Delta, Fannin, Franklin, Grayson, Gregg, Hardin, Harrison, Hopkins, Houston, Jasper, Lamar, Liberty, Marion, Montgomery, Morris, Nacogdoches, Newton, Panola, Polk, Rains, Red River, Rusk, Sabine, San Augustine, San Jacinto, Shelby, Smith, Titus, Trinity, Tyler, Upshur, Van Zandt, Walker, Wood County(ies)

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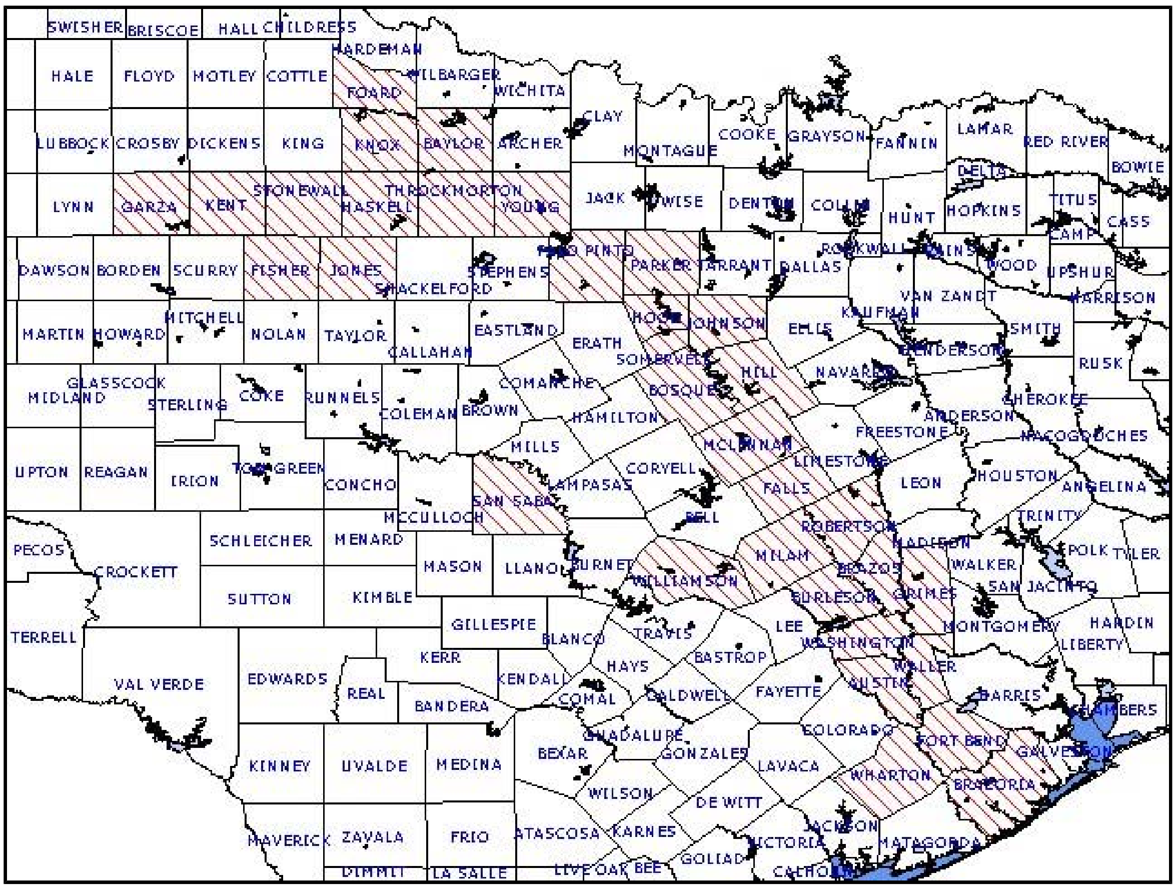
Sharpnose shiner *Notropis oxyrhynchus*
Federal Status: C **State Status:**

endemic to Brazos River drainage; also, apparently introduced into adjacent Colorado River drainage; large turbid river, with bottom a combination of sand, gravel, and clay-mud

Revision Date: 08/05/2009

potential or known presence within county



Austin, Baylor, Bosque, Brazoria, Brazos, Burleson, Falls, Fisher, Foard, Fort Bend, Garza, Grimes, Haskell, Hill, Hood, Johnson, Jones, Kent, Knox, McLennan, Milam, Palo Pinto, Parker, Robertson, San Saba, Somervell, Stonewall, Throckmorton, Waller, Washington, Wharton, Williamson, Young County(ies)

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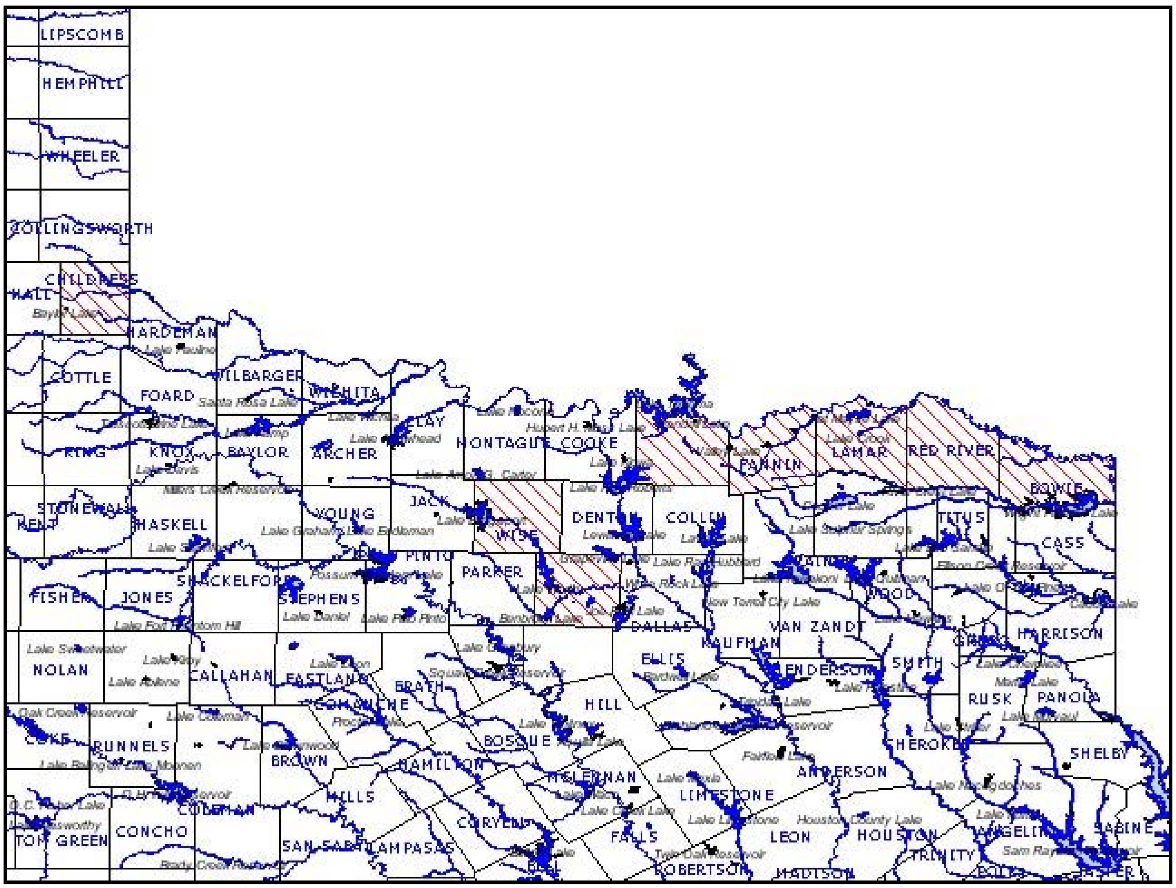
Shovelnose sturgeon ***Scaphirhynchus platorynchus***

Federal Status: **State Status: T**

open, flowing channels with bottoms of sand or gravel; spawns over gravel or rocks in an area with a fast current; Red River below reservoir and rare occurrence in Rio Grande

Revision Date: 07/16/2009

potential or known presence within county



Bowie, Childress, Fannin, Grayson, Lamar, Red River, Tarrant, Wise County(ies)

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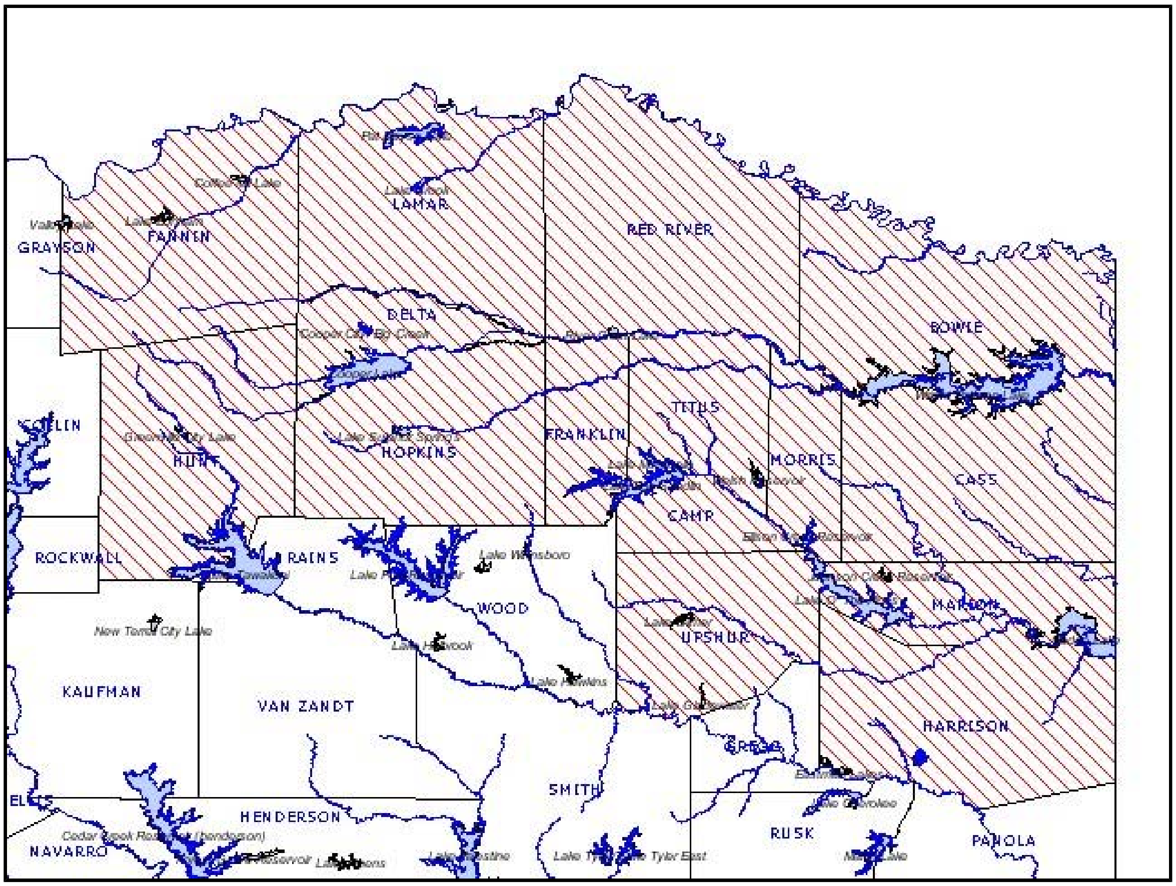
Taillight shiner *Notropis maculatus*

Federal Status: **State Status:**

Sulfur River and Big Cypress Bayou; mostly headwaters, typically large sluggish, mud-bottomed small to large streams and lakes, usually with some aquatic vegetation; spawns March-October in backwaters and pools; feeds mainly on insect larva and cladocerans, also algae

Revision Date: 07/16/2009

potential or known presence within county



Bowie, Camp, Cass, Delta, Fannin, Franklin, Harrison, Hopkins, Hunt, Lamar, Marion, Morris, Red River, Titus, Upshur County(ies)

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Rare, Threatened, and Endangered Species of Texas

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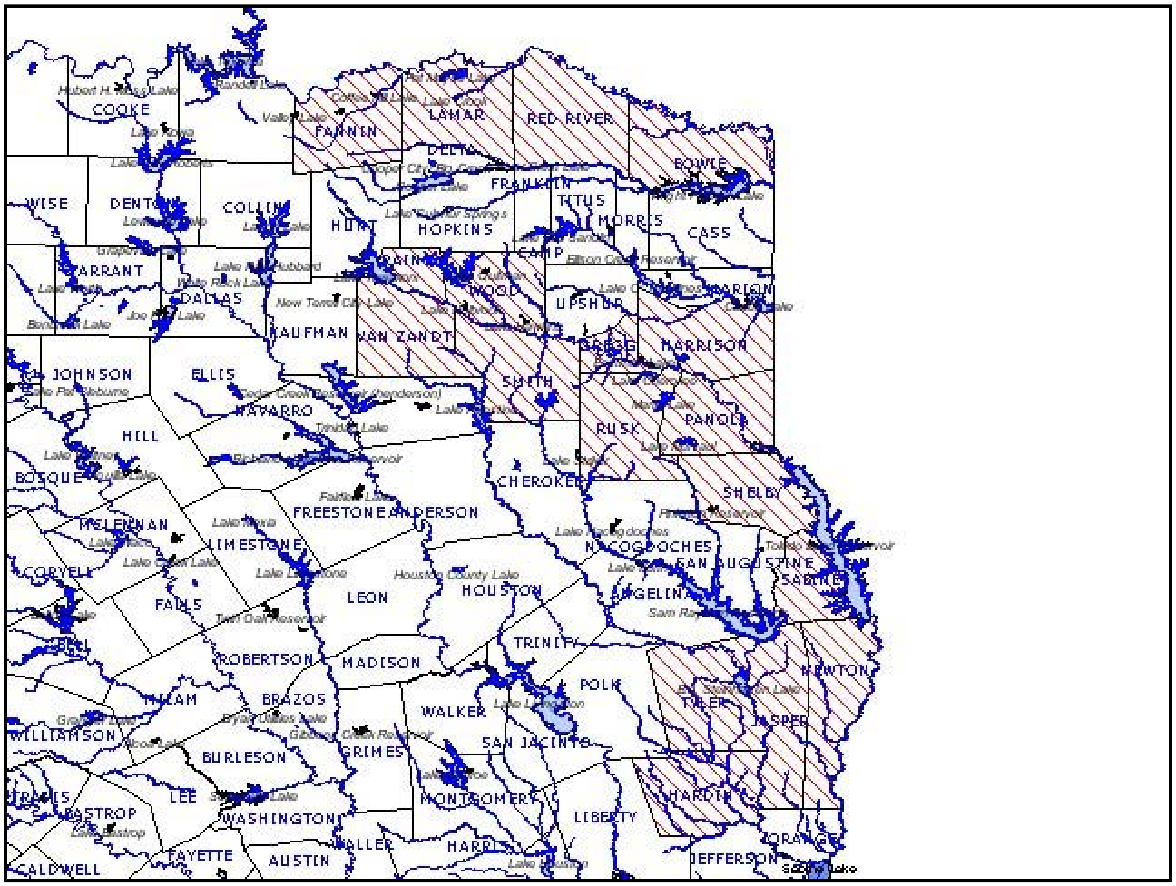
Western sand darter *Ammocrypta clara*

Federal Status: **State Status:**

Red and Sabine River basins; clear to slightly turbid water of medium to large rivers that have moderate to swift currents, primarily over extensive areas of sandy substrate

Revision Date: 07/16/2009

potential or known presence within county



Bowie, Fannin, Gregg, Hardin, Harrison, Jasper, Lamar, Newton, Panola, Rains, Red River, Rusk, Sabine, Shelby, Smith, Tyler, Van Zandt, Wood County(ies)

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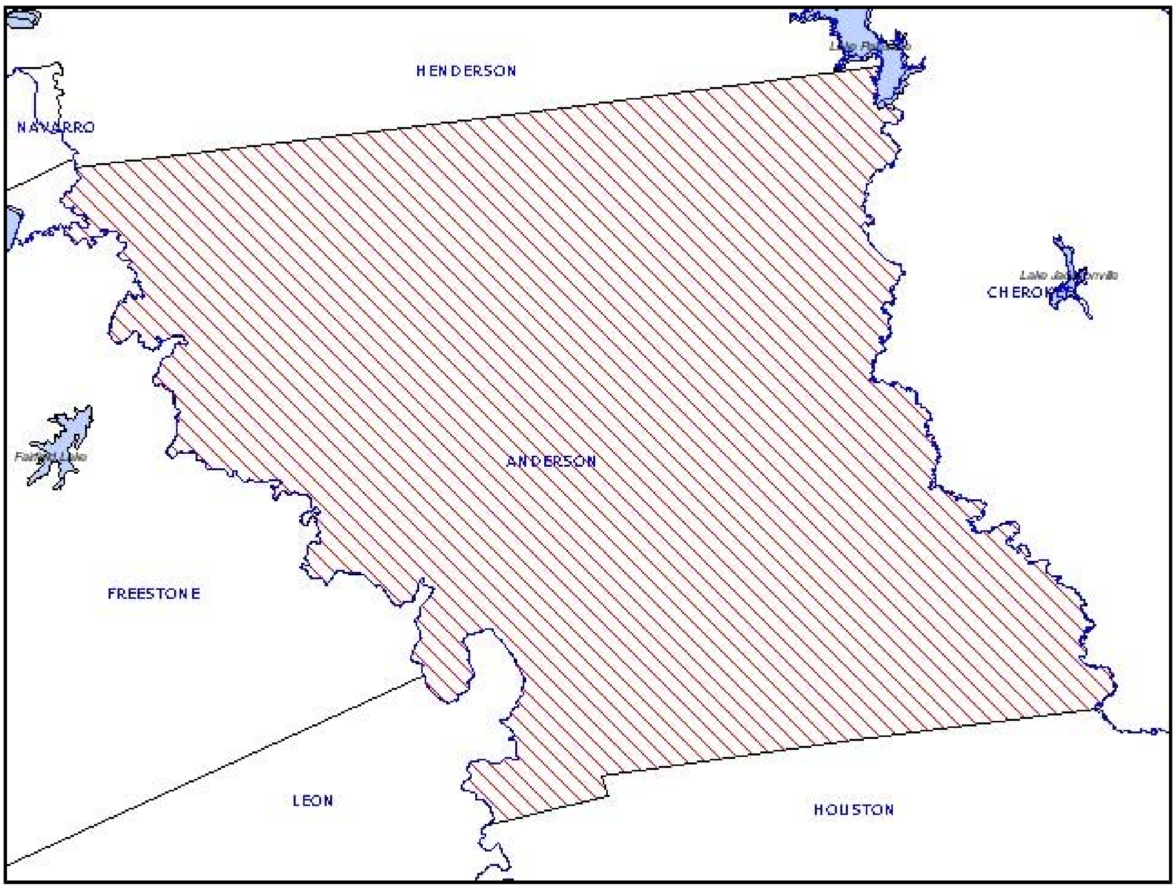
A caddisfly — *Phylocentropus harrisi*

Federal Status: — State Status:

lotic systems, but specifics unknown

Revision Date: 04/06/2006 — potential or known presence within county



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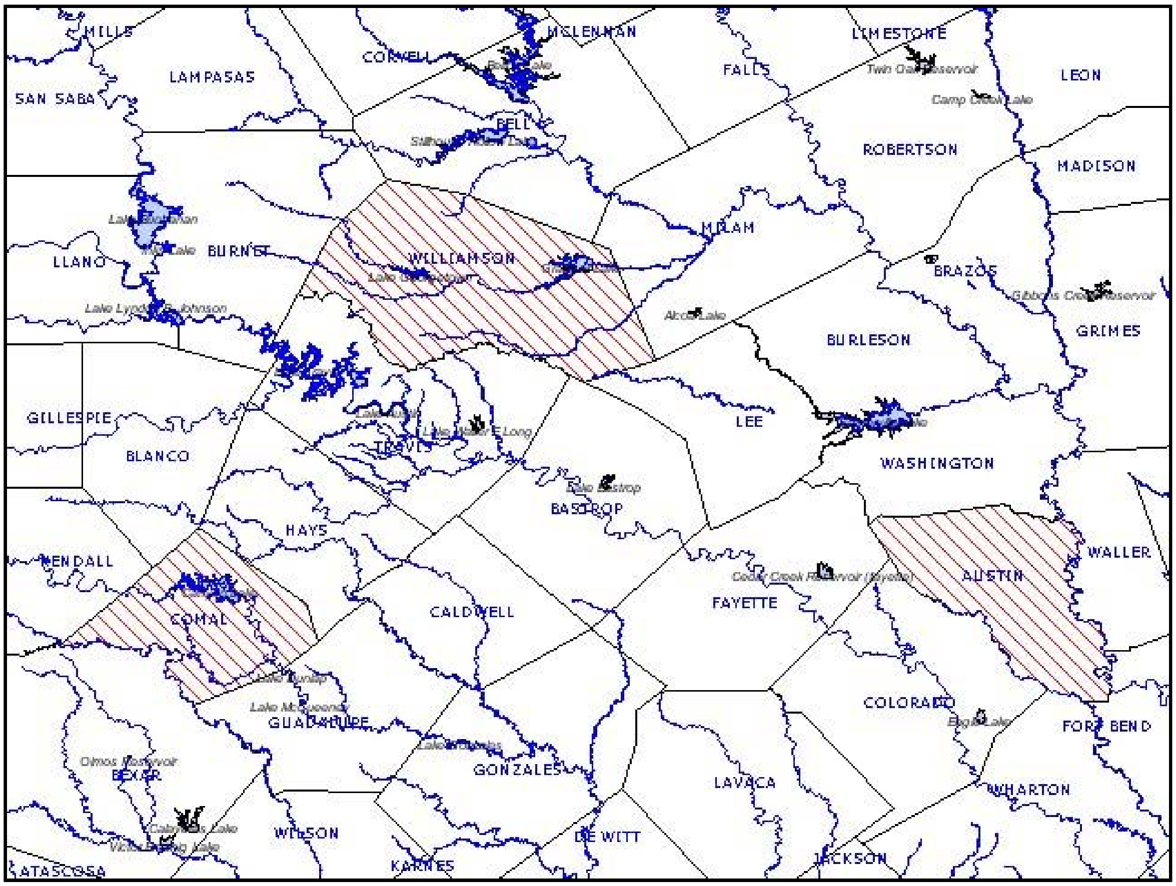
A mayfly *Pseudocentroptiloides morihari*

Federal Status: **State Status:**

mayflies distinguished by aquatic larval stage; adult stage generally found in shoreline vegetation

Revision Date: 06/26/2003

potential or known presence within county



Austin, Comal, Williamson County(ies)

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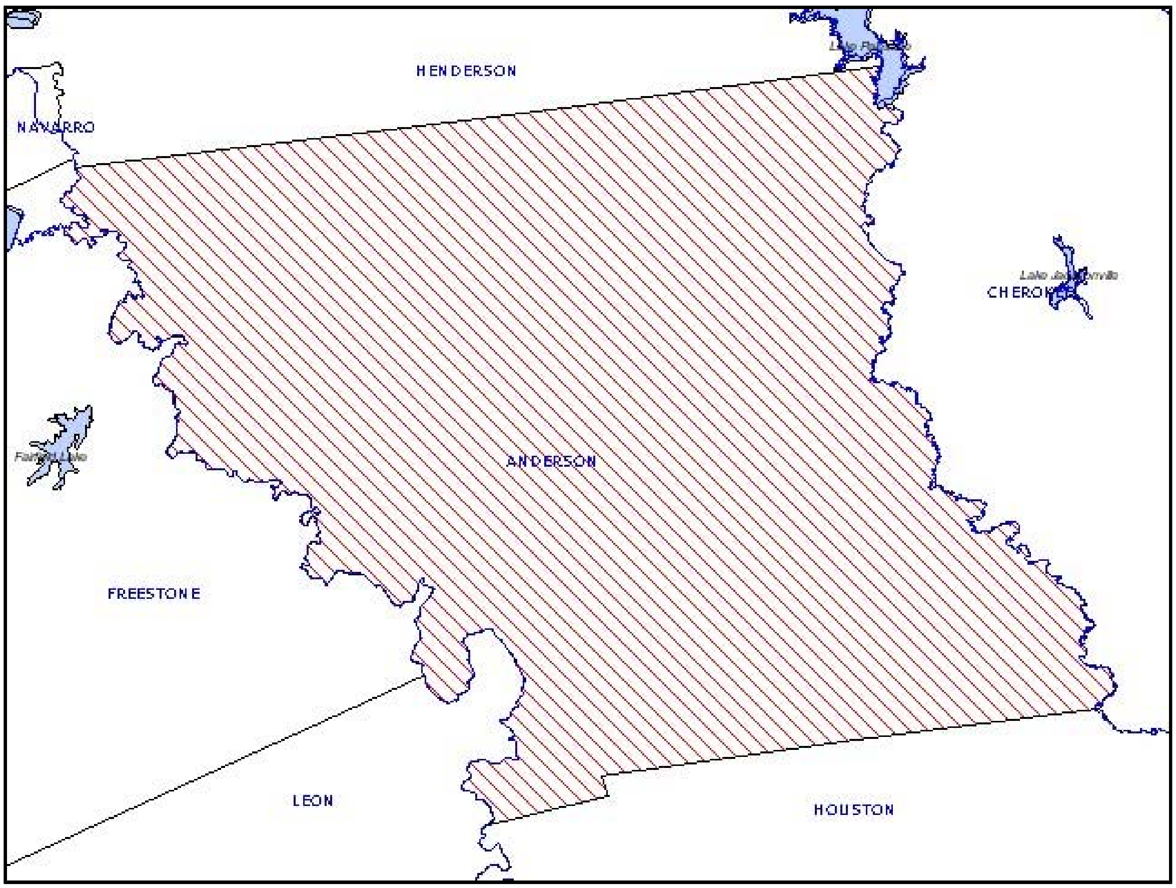
A Purse casemaker caddisfly *Hydroptila ouachita*
Federal Status: **State Status:**

lotic systems, but specifics unknown

Revision Date: 5/21/05

potential or known presence within county



Anderson County(ies)

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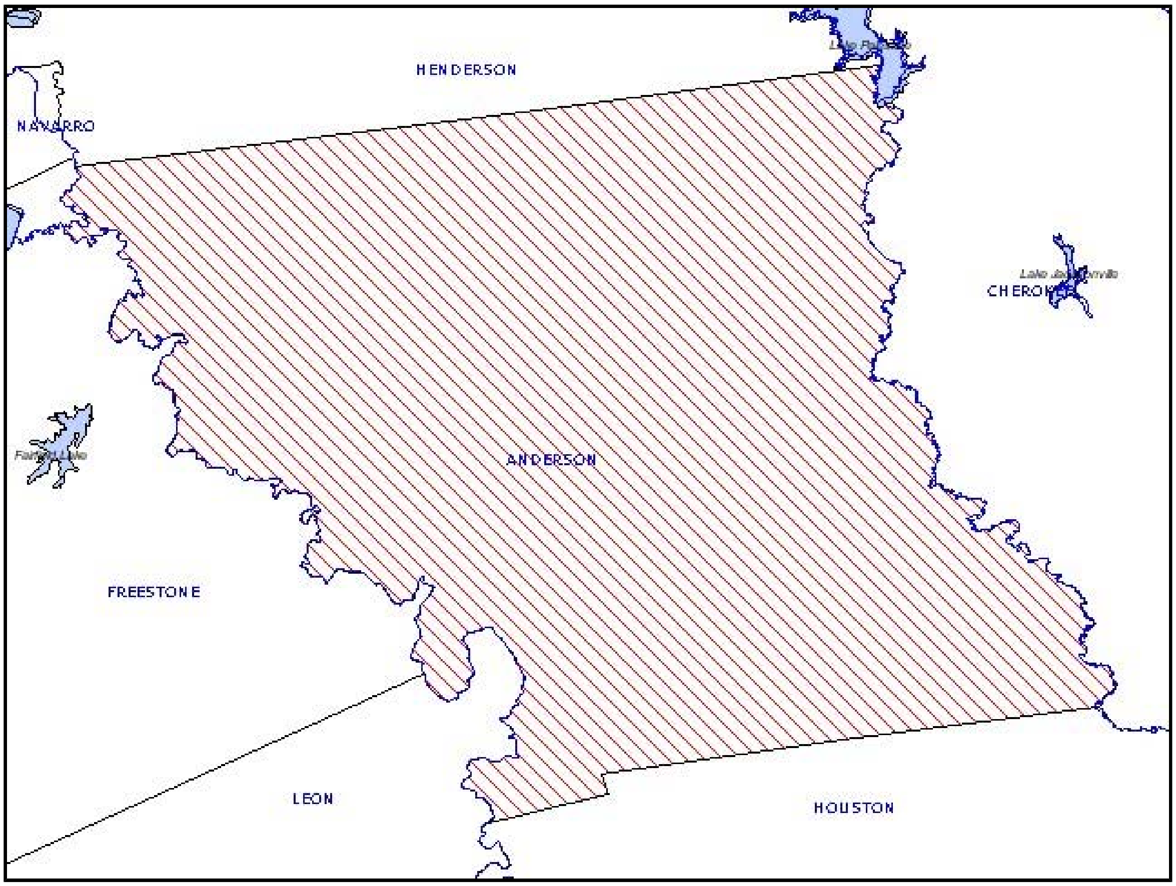
Holzenthal's philopotamid caddisfly *Chimarra holzenthali*

Federal Status: **State Status:**

Trinity River basin

Revision Date: 05/19/2006

potential or known presence within county



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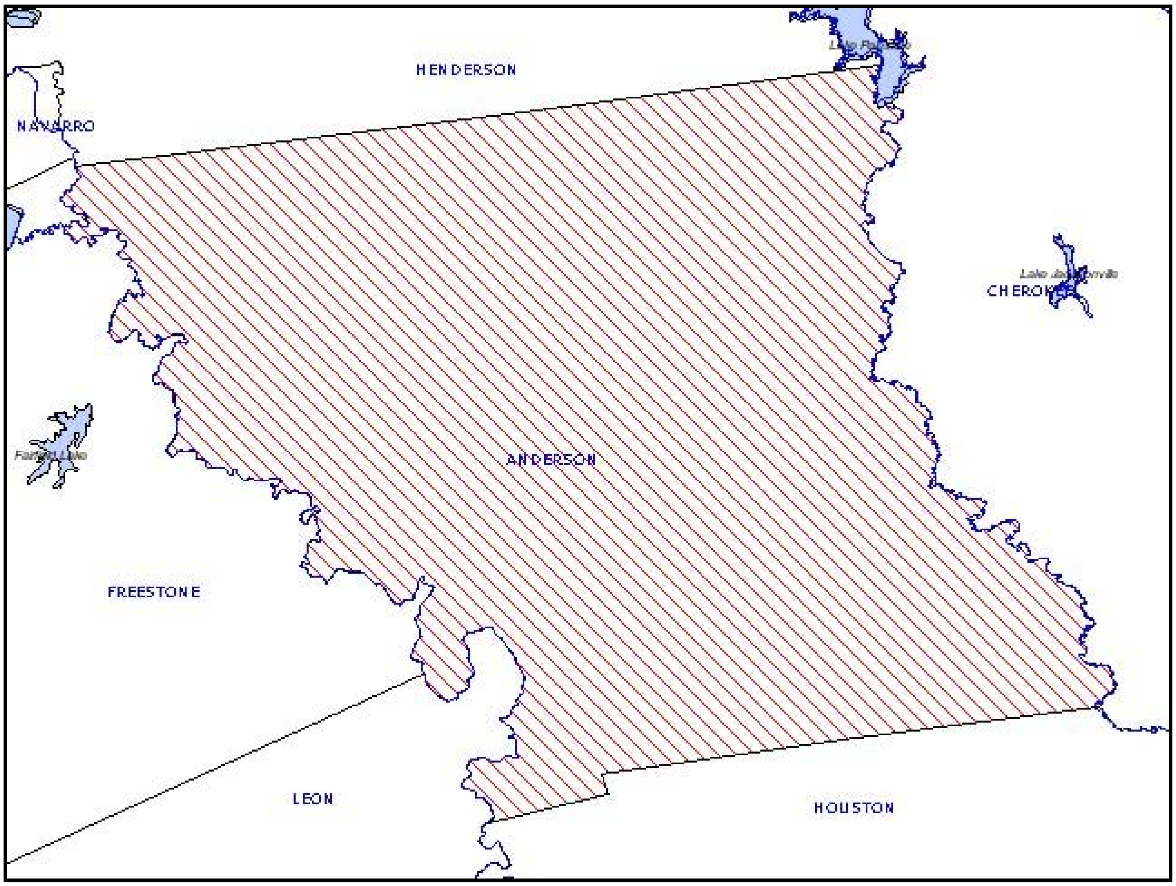
Morse's net-spinning caddisfly ***Cheumatopsyche morsei***

Federal Status: **State Status:**

lotic systems, but specifics unknown

Revision Date: 5/21/05

potential or known presence within county



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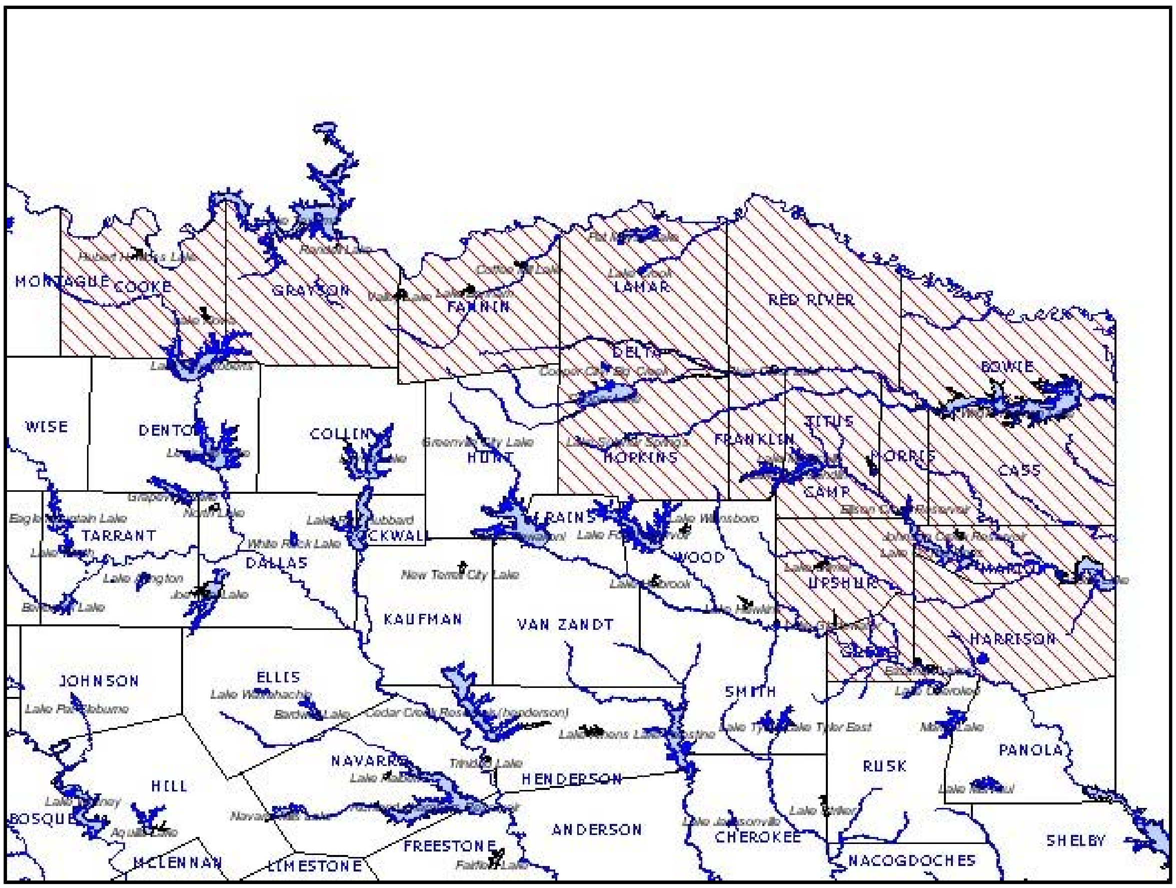
Common pimpleback — ***Quadrula pustulosa***

Federal Status: — **State Status:**

small streams to larger rivers, and associated with nearly every bottom type except deep shifting sands; Red River downstream of Lake Texoma and possibly Big Cypress Bayou and lower Sulphur river basins

Revision Date: 03/21/2006

potential or known presence within county



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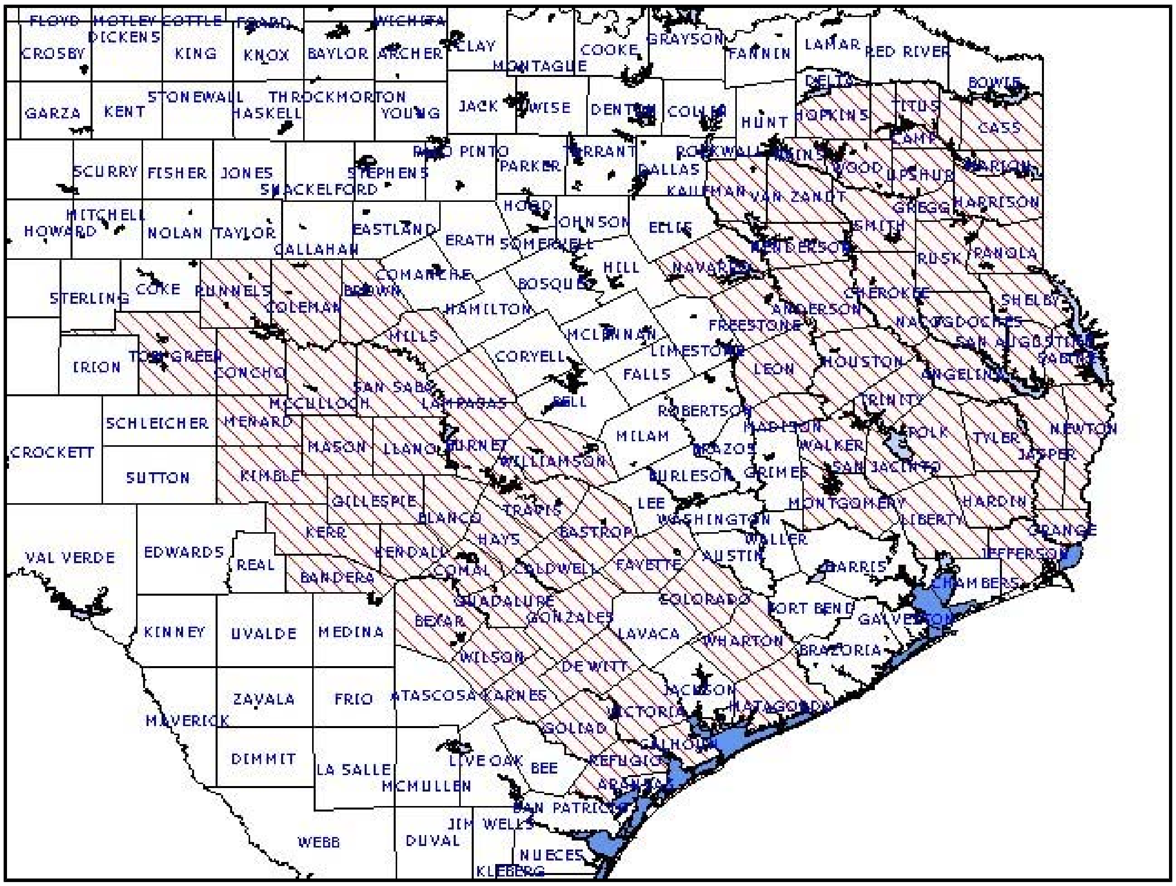
Creeper (squawfoot) *Strophitus undulatus*
Federal Status: **State Status:**

small to large streams, prefers gravel or gravel and mud in flowing water; Colorado, Guadalupe, San Antonio, Neches (historic), and Trinity (historic) River basins

Revision Date: 03/21/2006

potential or known presence within county



Anderson, Angelina, Bandera, Bastrop, Bexar, Blanco, Brown, Burnet, Caldwell, Calhoun, Camp, Cass, Cherokee, Coleman, Colorado, Comal, Concho, De Witt, Fayette, Franklin, Freestone, Gillespie, Goliad, Gonzales, Gregg, Guadalupe, Hardin, Harrison, Hays, Henderson, Hopkins, Houston, Jasper, Jefferson, Karnes, Kaufman, Kendall, Kerr, Kimble, Lampasas, Leon, Liberty, Llano, Madison, Marion, Mason, Matagorda, McCulloch, Menard, Mills, Montgomery, Morris, Nacogdoches, Navarro, Newton, Orange, Panola, Polk, Rains, Refugio, Runnels, Rusk, Sabine, San Augustine, San Jacinto, San Saba, Shelby, Smith, Titus, Tom Green, Travis, Trinity, Tyler, Upshur, Van Zandt, Victoria, Walker, Wharton, Williamson, Wilson, Wood County(ies)

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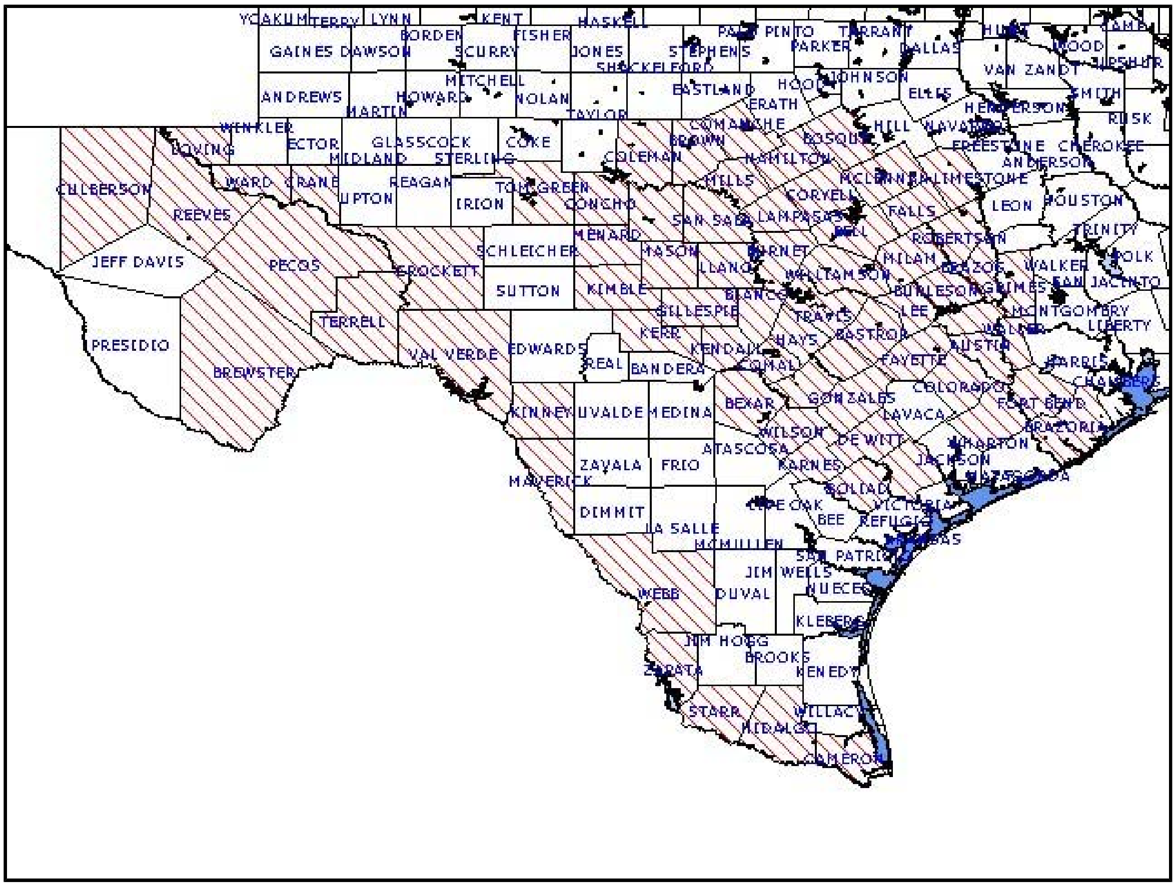
False spike mussel *Quincuncina mitchelli*
Federal Status: **State Status: T**

substrates of cobble and mud, with water lilies present; Rio Grande, Brazos, Colorado, and Guadalupe (historic) river basins

Revision Date: 01/15/2010

potential or known presence within county



Austin, Bastrop, Bell, Bexar, Blanco, Bosque, Brazoria, Brazos, Brewster, Brown, Burleson, Burnet, Caldwell, Cameron, Coleman, Colorado, Comal, Comanche, Concho, Coryell, Crane, Crockett, Culberson, De Witt, Falls, Fayette, Fort Bend, Gillespie, Goliad, Gonzales, Grimes, Guadalupe, Hamilton, Hays, Hidalgo, Karnes, Kendall, Kerr, Kimble, Kinney, Lampasas, Lee, Limestone, Llano, Loving, Mason, Maverick, McCulloch, McLennan, Menard, Milam, Mills, Pecos, Reeves, Robertson, San Saba, Starr, Terrell, Tom Green, Travis, Val Verde, Victoria, Waller, Ward, Washington, Webb, Wharton, Williamson, Wilson, Zapata County(ies)

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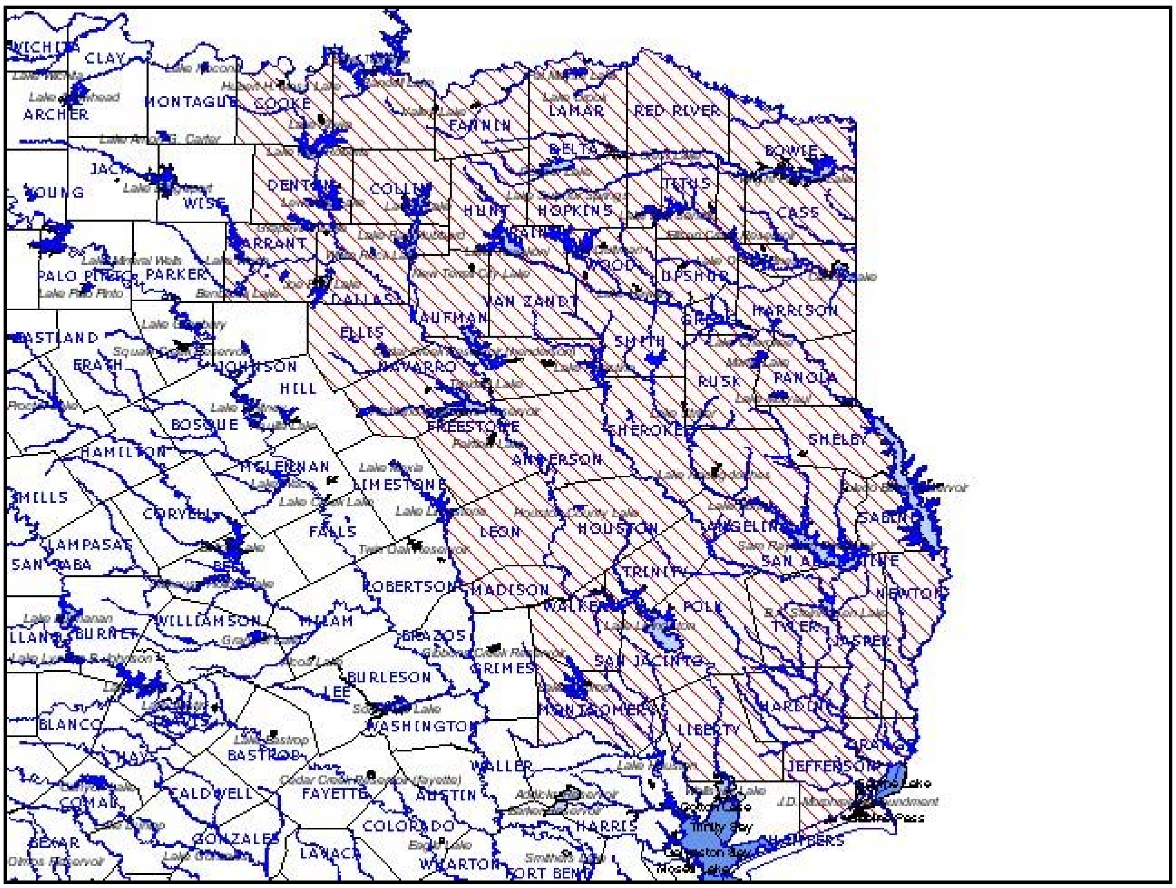
Fawnsfoot *Truncilla donaciformis*

Federal Status: **State Status:**

small and large rivers especially on sand, mud, rocky mud, and sand and gravel, also silt and cobble bottoms in still to swiftly flowing waters; Red (historic), Cypress (historic), Sabine (historic), Neches, Trinity, and San Jacinto River basins.

Revision Date: 03/21/2006

potential or known presence within county



Anderson, Angelina, Bowie, Camp, Cass, Cherokee, Collin, Cooke, Dallas, Delta, Denton, Ellis, Fannin, Franklin, Freestone, Grayson, Gregg, Hardin, Harrison, Henderson, Hopkins, Houston, Hunt, Jasper, Jefferson, Kaufman, Lamar, Leon, Liberty, Madison, Marion, Montgomery, Morris, Nacogdoches, Navarro, Newton, Orange, Panola, Polk, Rains, Red River, Rockwall, Rusk, Sabine, San Augustine, San Jacinto, Shelby, Smith, Tarrant, Titus, Trinity, Tyler, Upshur, Van Zandt, Walker, Wood County(ies)

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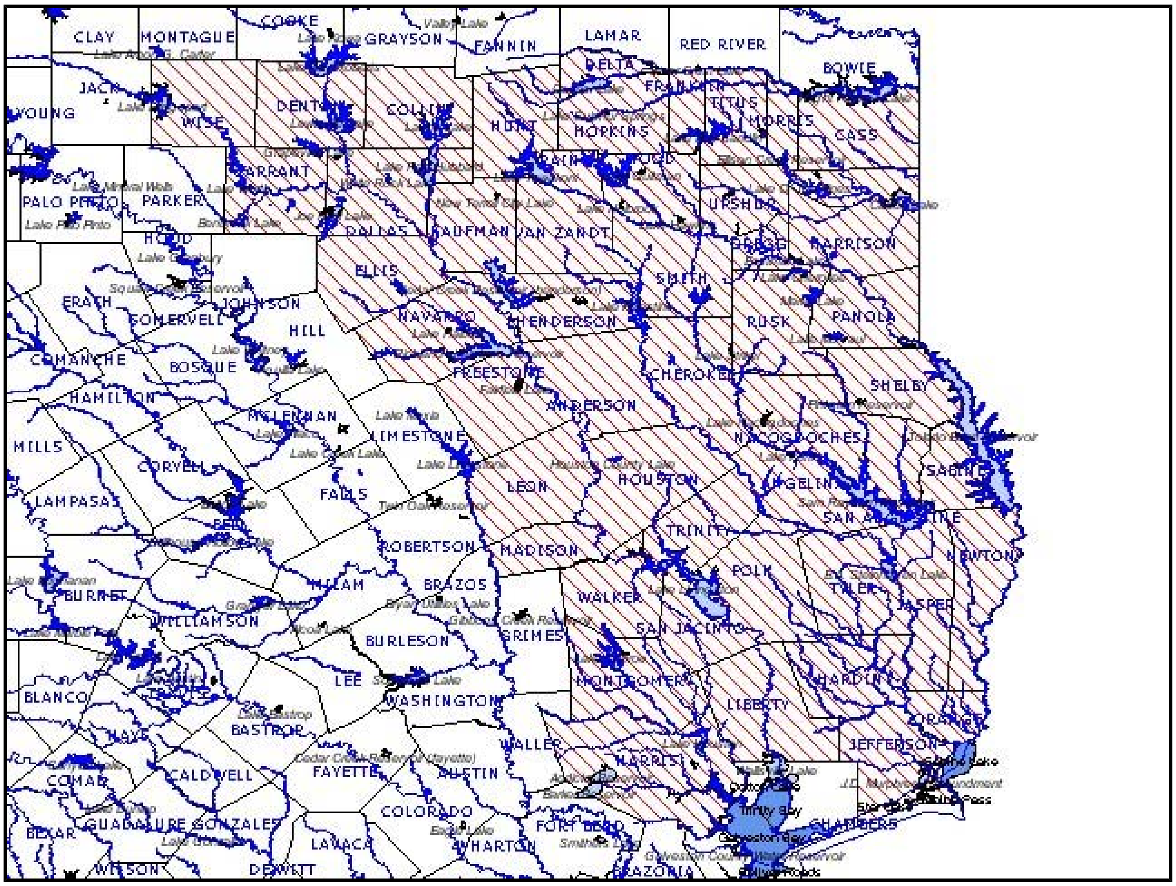
Little spectaclecase *Villosa lienosa*

Federal Status: **State Status:**

creeks, rivers, and reservoirs, sandy substrates in slight to moderate current, usually along the banks in slower currents; east Texas, Cypress through San Jacinto River basins

Revision Date: 03/21/2006

potential or known presence within county



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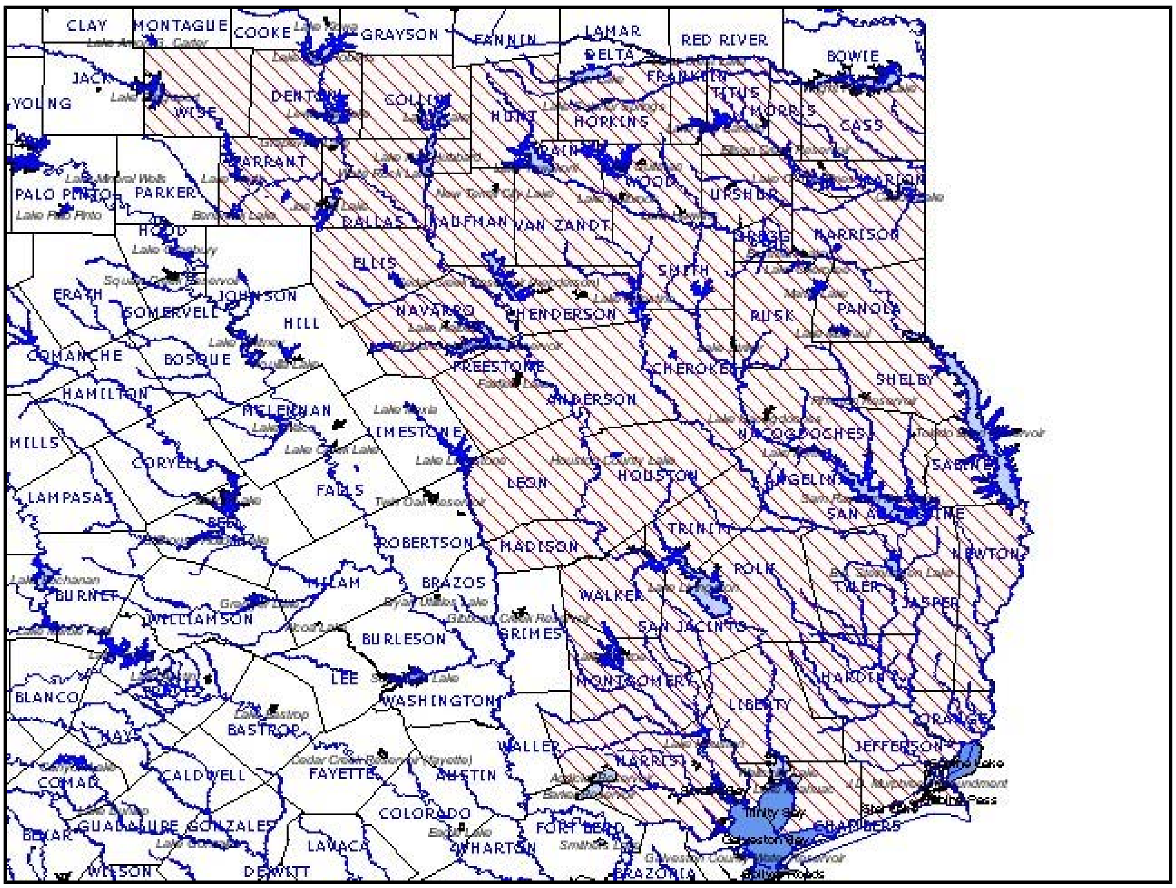
Louisiana pigtoe	***Pleurobema riddellii***
Federal Status:	**State Status: T**

streams and moderate-size rivers, usually flowing water on substrates of mud, sand, and gravel; not generally known from impoundments; Sabine, Neches, and Trinity (historic) River basins

Revision Date: 01/15/2010

potential or known presence within county



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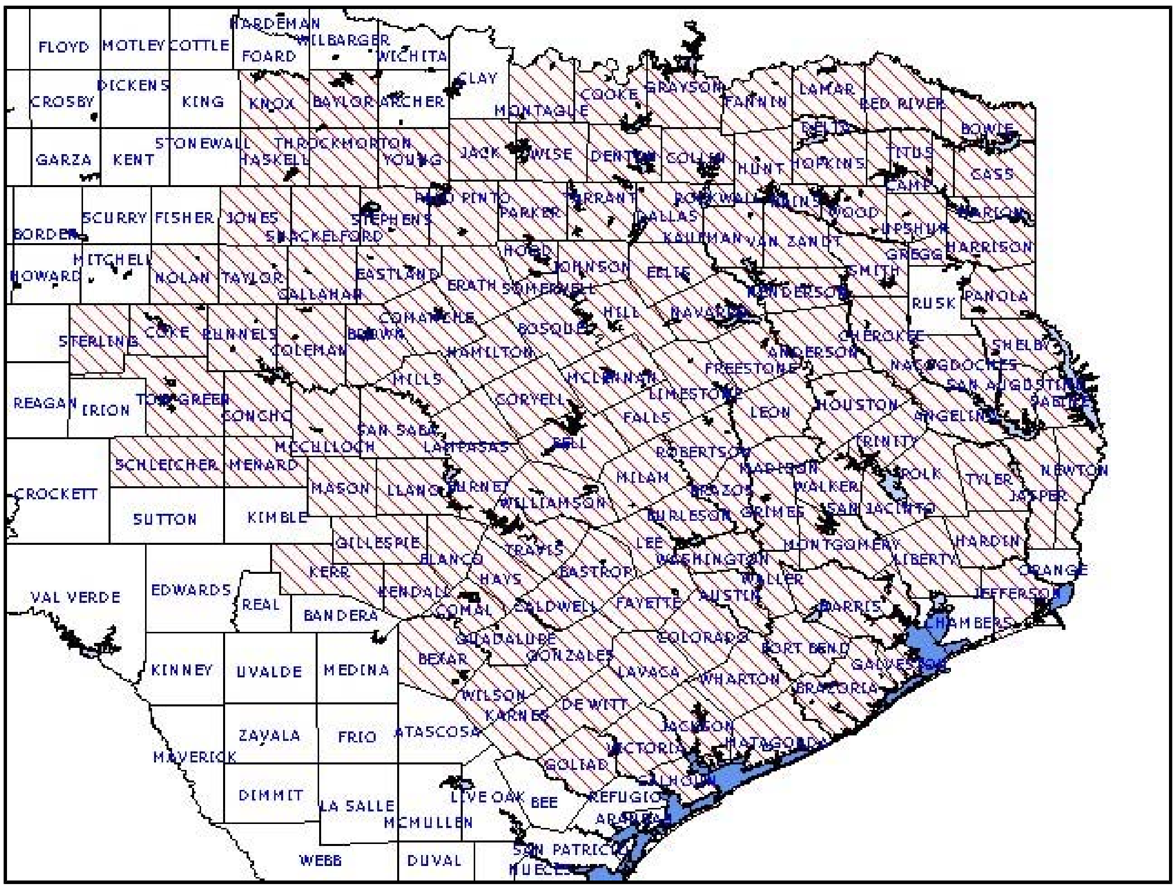
Pistolgrip *Tritogonia verrucosa*

Federal Status: **State Status:**

stable substrate, rock, hard mud, silt, and soft bottoms, often buried deeply; east and central Texas, Red through San Antonio River basins

Revision Date: 03/21/2006

potential or known presence within county



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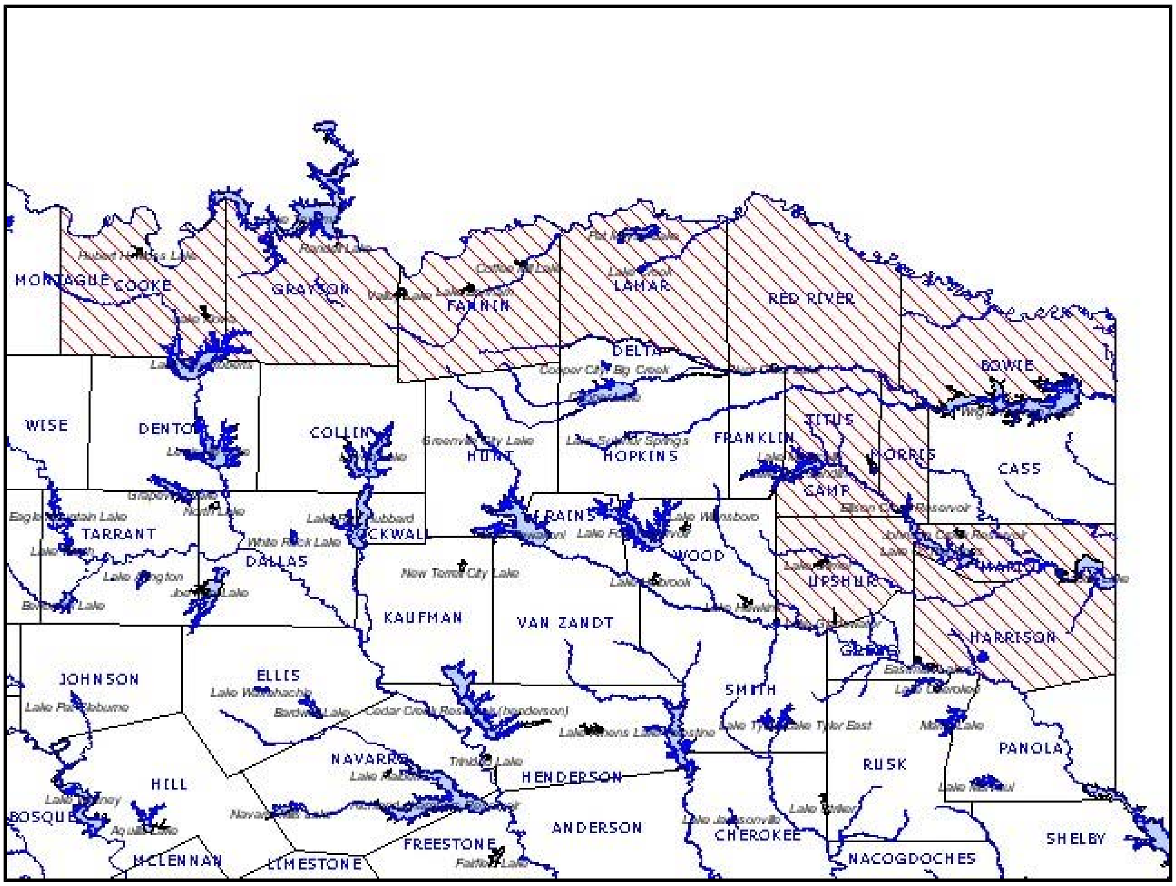
Plain pocketbook *Lampsilis cardium*
Federal Status: **State Status:**

small creeks and large rivers, flowing waters, occasionally oxbows or slackwater areas of sandy-bottomed rivers and reservoirs on sand, sand-gravel, or sand-mud but not typically in dense beds; Red and Cypress River basins

Revision Date: 03/21/2006

potential or known presence within county



Bowie, Camp, Cooke, Fannin, Grayson, Harrison, Lamar, Marion, Morris, Red River, Titus, Upshur County(ies)

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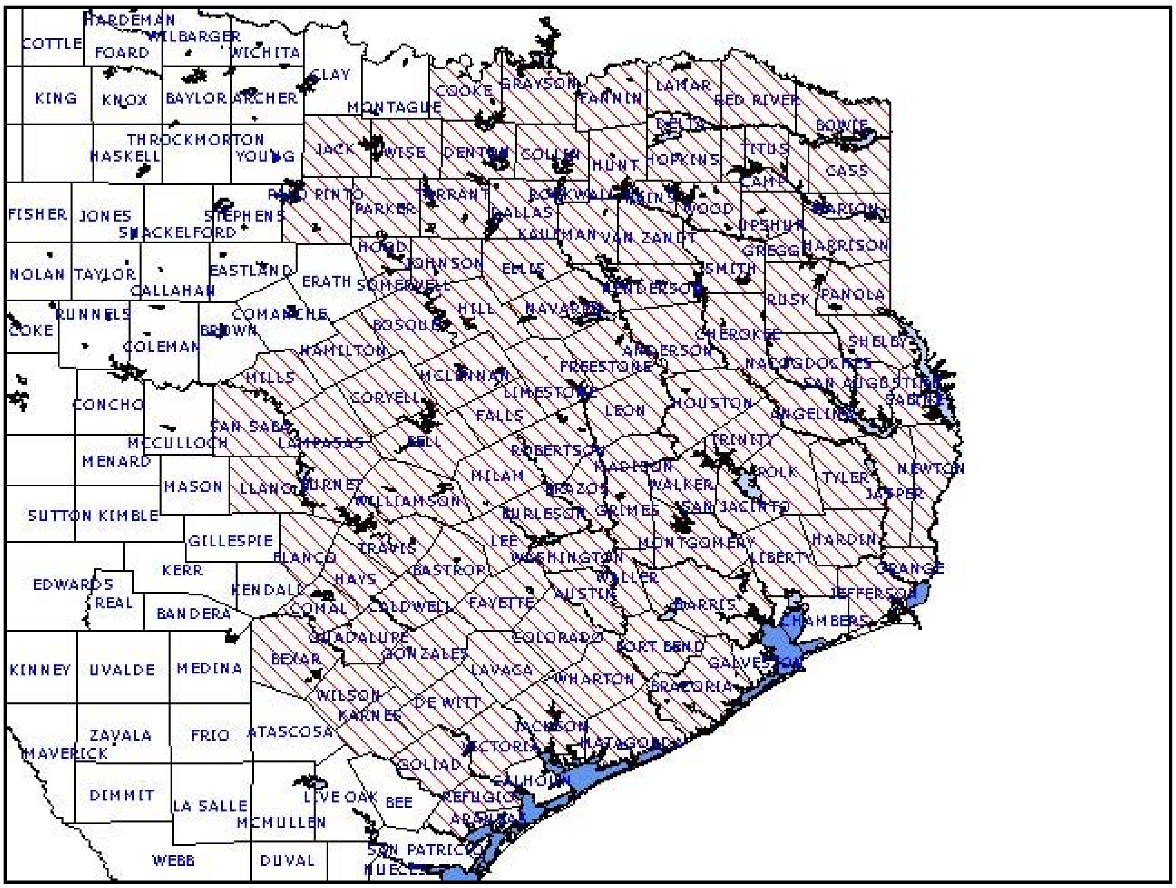
Rock pocketbook *Arcidens confragosus*

Federal Status: **State Status:**

mud, sand, and gravel substrates of medium to large rivers in standing or slow flowing water, may tolerate moderate currents and some reservoirs, east Texas, Red through Guadalupe River basins

Revision Date: 05/03/2007

potential or known presence within county



Anderson, Angelina, Austin, Bastrop, Bell, Bexar, Blanco, Bosque, Bowie, Brazoria, Brazos, Burleson, Burnet, Caldwell, Camp, Cass, Cherokee, Collin, Colorado, Comal, Cooke, Coryell, Dallas, De Witt, Delta, Denton, Ellis, Falls, Fannin, Fayette, Fort Bend, Franklin, Freestone, Goliad, Gonzales, Grayson, Gregg, Grimes, Guadalupe, Hamilton, Hardin, Harris, Harrison, Hays, Henderson, Hill, Hood, Hopkins, Houston, Hunt, Jack, Jackson, Jasper, Jefferson, Johnson, Karnes, Kaufman, Lamar, Lampasas, Lavaca, Lee, Leon, Liberty, Limestone, Llano, Madison, Marion, Matagorda, McLennan, Milam, Mills, Montgomery, Morris, Nacogdoches, Navarro, Newton, Orange, Palo Pinto, Panola, Parker, Polk, Rains, Red River, Refugio, Robertson, Rockwall, Rusk, Sabine, San Augustine, San Jacinto, San Saba, Shelby, Smith, Somervell, Tarrant, Titus, Travis, Trinity, Tyler, Upshur, Van Zandt, Victoria, Walker, Waller, Washington, Wharton, Williamson, Wilson, Wise, Wood County(ies)

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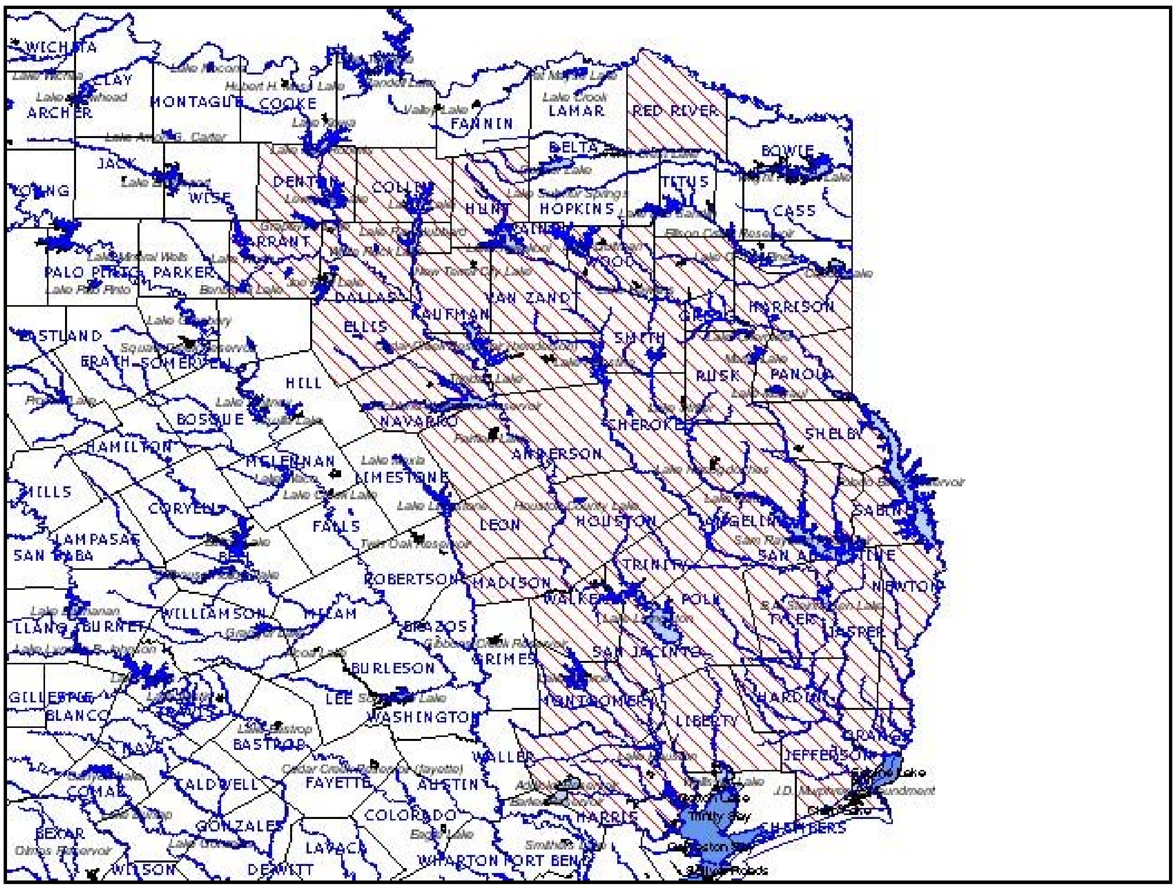
Sandbank pocketbook — ***Lampsilis satura***

Federal Status: — **State Status: T**

small to large rivers with moderate flows and swift current on gravel, gravel-sand, and sand bottoms; east Texas, Sulfur south through San Jacinto River basins; Neches River

Revision Date: 01/15/2010

potential or known presence within county



Anderson, Angelina, Cherokee, Collin, Dallas, Denton, Ellis, Freestone, Gregg, Hardin, Harris, Harrison, Henderson, Houston, Hunt, Jasper, Jefferson, Kaufman, Leon, Liberty, Madison, Montgomery, Nacogdoches, Navarro, Newton, Orange, Panola, Polk, Rains, Red River, Rockwall, Rusk, Sabine, San Augustine, San Jacinto, Shelby, Smith, Tarrant, Trinity, Tyler, Upshur, Van Zandt, Walker, Wood County(ies)

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Rare, Threatened, and Endangered Species of Texas

Search by...

Type full or partial County Name and click "GO"

Leave blank and click "GO" for a complete list

OR

Type full or partial Common Name and click "GO"

Leave blank and click "GO" for a complete list

OR

Type full or partial Scientific Name and click "GO"

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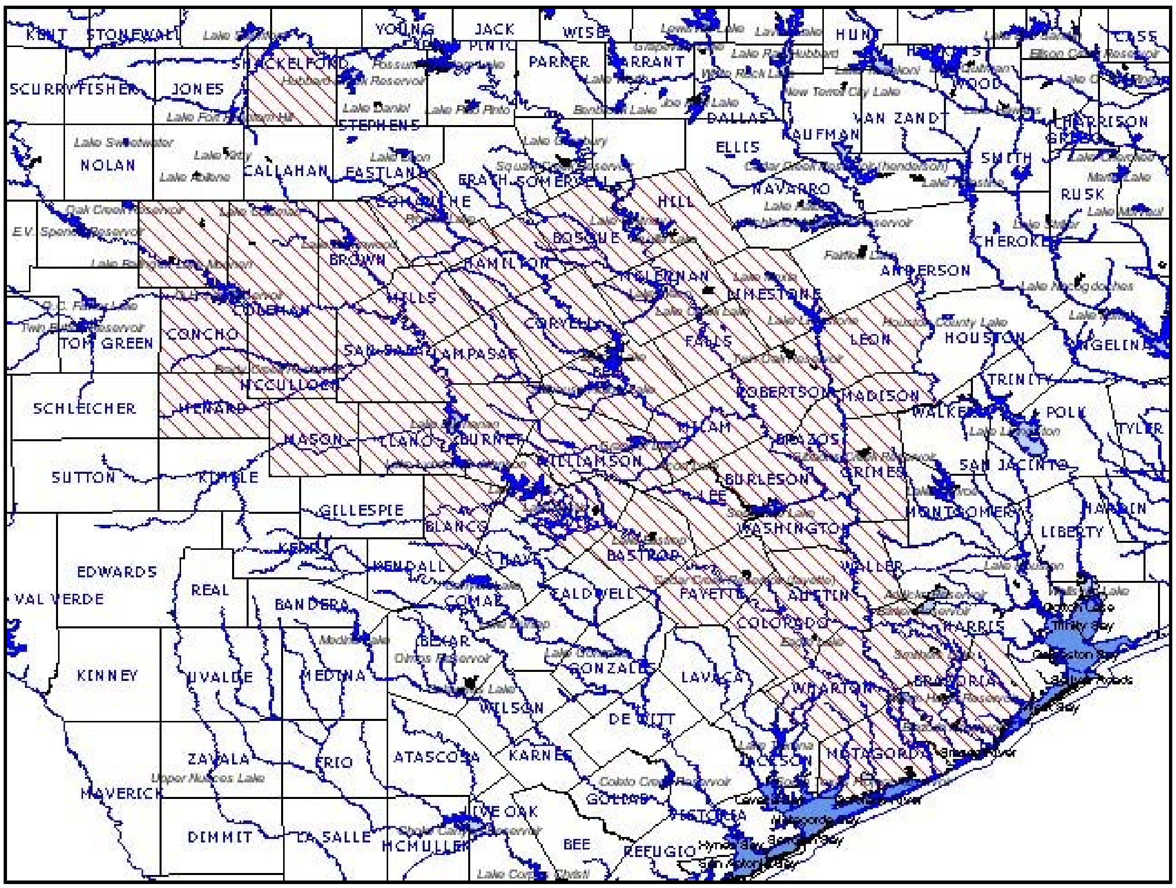
Smooth pimpleback *Quadrula houstonensis*

Federal Status: **State Status: T**

small to moderate streams and rivers as well as moderate size reservoirs; mixed mud, sand, and fine gravel, tolerates very slow to moderate flow rates, appears not to tolerate dramatic water level fluctuations, scoured bedrock substrates, or shifting sand bottoms, lower Trinity (questionable), Brazos, and Colorado River basins

Revision Date: 01/15/2010 **potential or known presence within county**



Austin, Bastrop, Bell, Blanco, Bosque, Brazoria, Brazos, Brown, Burleson, Burnet, Coleman, Colorado, Comanche, Concho, Coryell, Falls, Fayette, Fort Bend, Grimes, Hamilton, Hill, Lampasas, Lee, Leon, Limestone, Llano, Madison, Mason, Matagorda, McCulloch, McLennan, Menard, Milam, Mills, Robertson, Runnels, San Saba, Shackelford, Travis, Waller, Washington, Wharton, Williamson County(ies)

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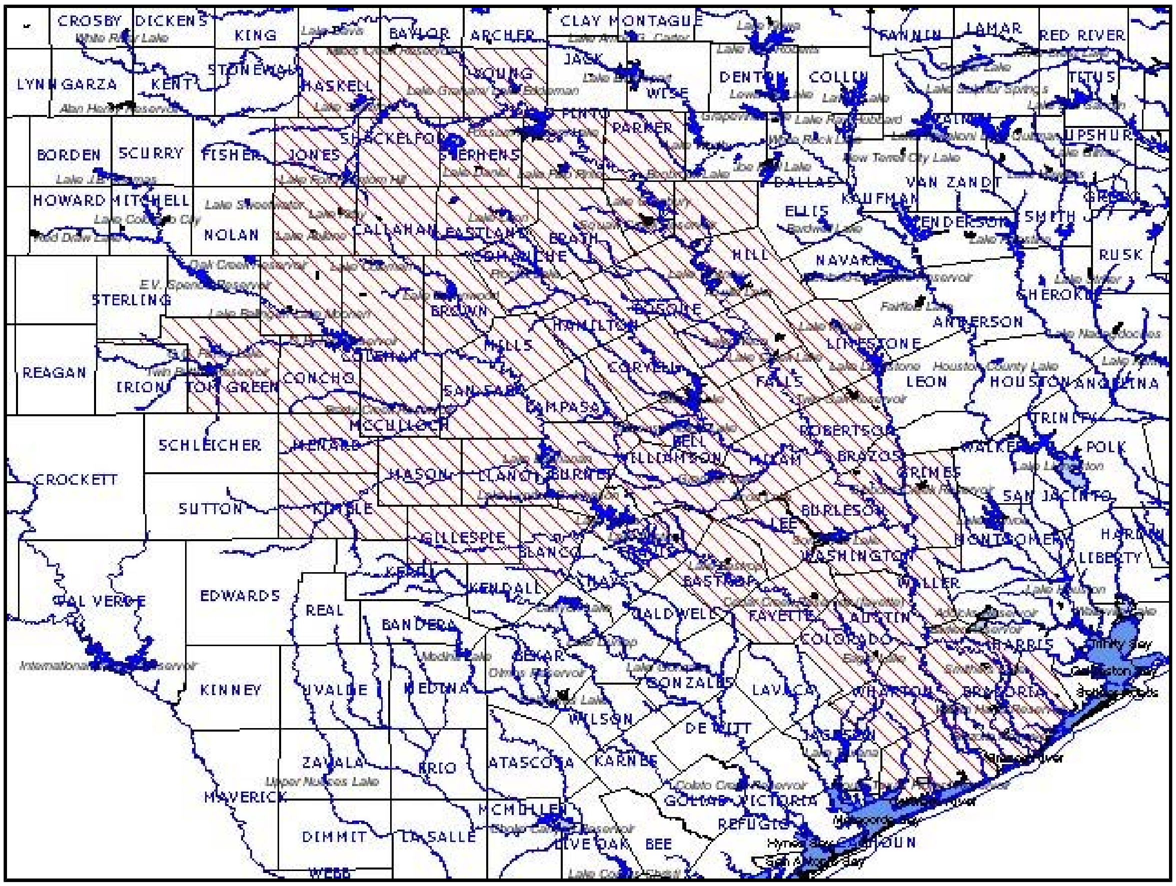
Texas fawnsfoot — ***Truncilla macrodon***

Federal Status: — **State Status: T**

little known; possibly rivers and larger streams, and intolerant of impoundment; flowing rice irrigation canals, possibly sand, gravel, and perhaps sandy-mud bottoms in moderate flows; Brazos and Colorado River basins

Revision Date: 01/15/2010

potential or known presence within county



Austin, Bastrop, Bell, Blanco, Bosque, Brazoria, Brazos, Brown, Burleson, Burnet, Callahan, Coleman, Colorado, Comanche, Concho, Coryell, Eastland, Erath, Falls, Fayette, Fort Bend, Gillespie, Grimes, Hamilton, Haskell, Hill, Hood, Johnson, Jones, Kimble, Lampasas, Lee, Limestone, Llano, Mason, Matagorda, McCulloch, McLennan, Menard, Milam, Mills, Palo Pinto, Parker, Robertson, Runnels, San Saba, Shackelford, Somervell, Stephens, Taylor, Throckmorton, Tom Green, Travis, Waller, Washington, Wharton, Williamson, Young County(ies)

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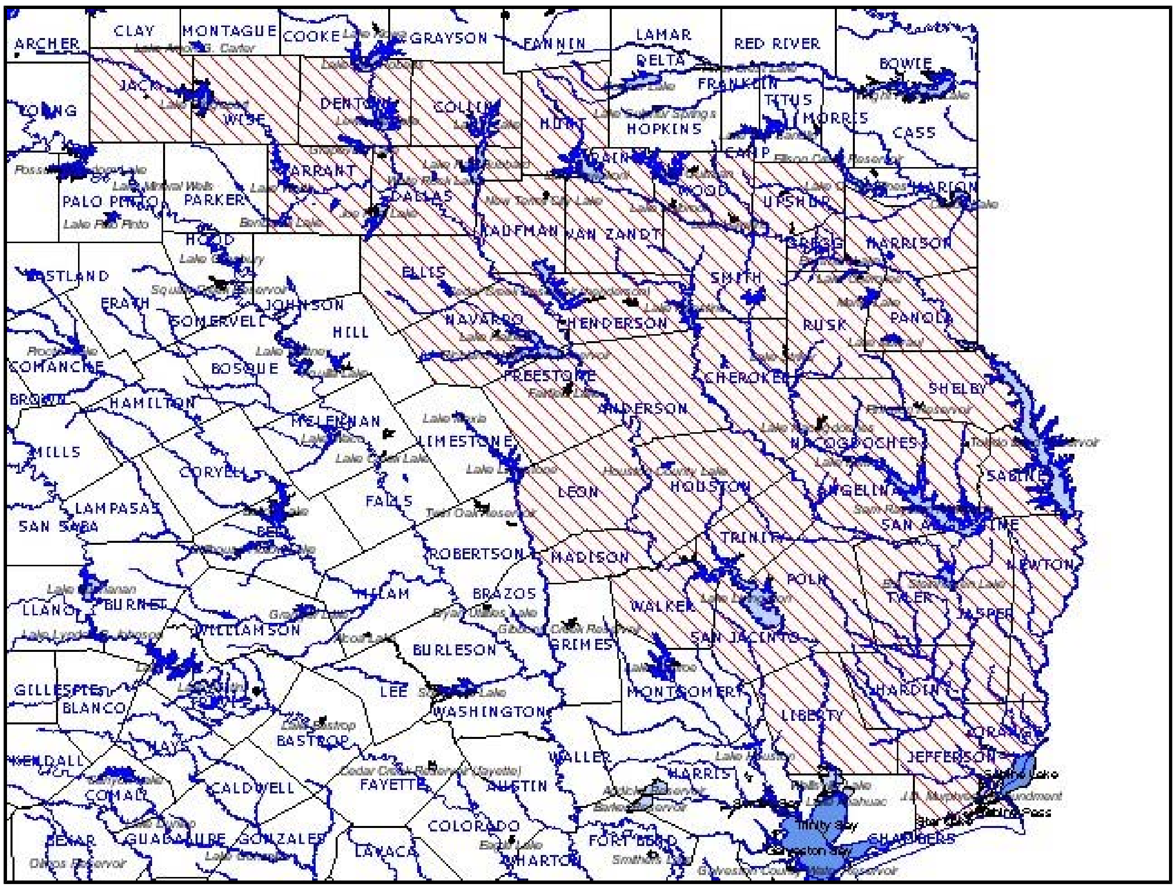
Texas heelsplitter	***Potamilus amphichaenus***
Federal Status:	**State Status: T**

quiet waters in mud or sand and also in reservoirs. Sabine, Neches, and Trinity River basins

Revision Date: 01/15/2010

potential or known presence within county



Anderson, Angelina, Cherokee, Collin, Dallas, Denton, Ellis, Freestone, Gregg, Hardin, Harrison, Henderson, Houston, Hunt, Jack, Jasper, Jefferson, Kaufman, Leon, Liberty, Madison, Nacogdoches, Navarro, Newton, Orange, Panola, Polk, Rains, Rockwall, Rusk, Sabine, San Augustine, San Jacinto, Shelby, Smith, Tarrant, Trinity, Tyler, Upshur, Van Zandt, Walker, Wise, Wood County(ies)

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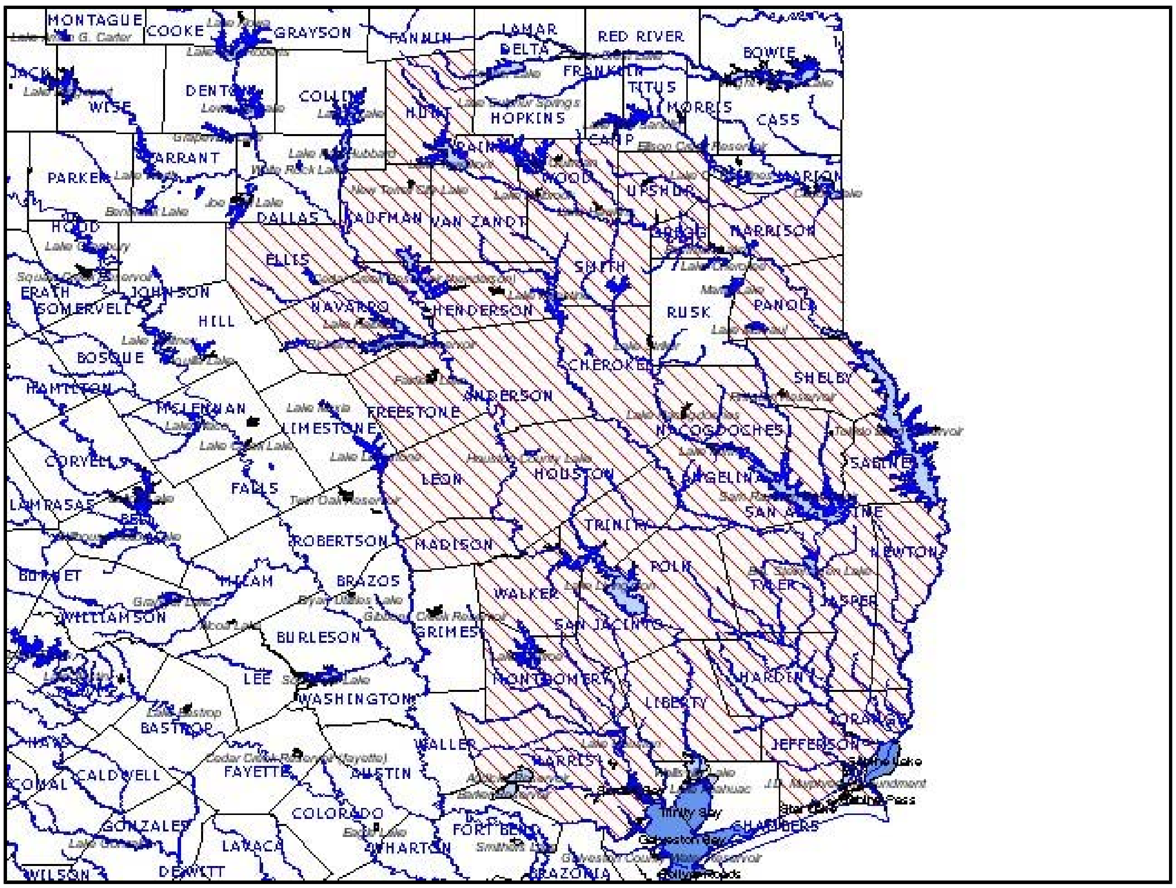
Texas pigtoe *Fusconaia askewi*

Federal Status: **State Status: T**

rivers with mixed mud, sand, and fine gravel in protected areas associated with fallen trees or other structures; east Texas River basins, Sabine through Trinity rivers as well as San Jacinto River

Revision Date: 01/15/2010

potential or known presence within county



Anderson, Angelina, Cherokee, Ellis, Freestone, Gregg, Hardin, Harris, Harrison, Henderson, Houston, Hunt, Jasper, Jefferson, Kaufman, Leon, Liberty, Madison, Montgomery, Nacogdoches, Navarro, Newton, Orange, Panola, Polk, Rains, Sabine, San Augustine, San Jacinto, Shelby, Smith, Trinity, Tyler, Upshur, Van Zandt, Walker, Wood County(ies)

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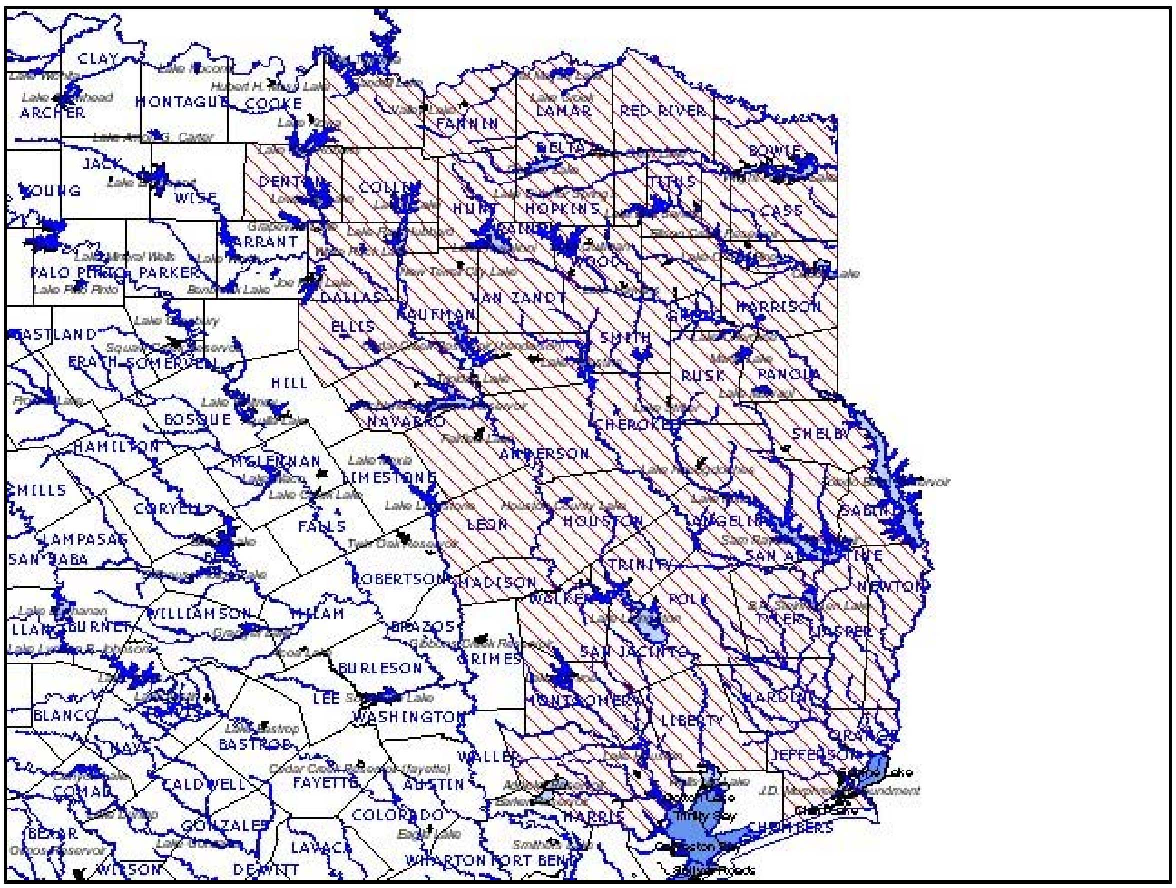
Wabash pigtoe *Fusconaia flava*

Federal Status: **State Status:**

creeks to large rivers on mud, sand, and gravel from all habitats except deep shifting sands; found in moderate to swift current velocities; east Texas River basins, Red through San Jacinto River basins; elsewhere occurs in reservoirs and lakes with no flow

Revision Date: 03/21/2006

potential or known presence within county



Anderson, Angelina, Bowie, Camp, Cass, Cherokee, Collin, Dallas, Delta, Denton, Ellis, Fannin, Franklin, Freestone, Grayson, Gregg, Hardin, Harris, Harrison, Henderson, Hopkins, Houston, Hunt, Jasper, Jefferson, Kaufman, Lamar, Leon, Liberty, Madison, Marion, Montgomery, Morris, Nacogdoches, Navarro, Newton, Orange, Panola, Polk, Rains, Red River, Rockwall, Rusk, Sabine, San Augustine, San Jacinto, Shelby, Smith, Titus, Trinity, Tyler, Upshur, Van Zandt, Walker, Wood County(ies)

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White heelsplitter — ***Lasmigona complanata***

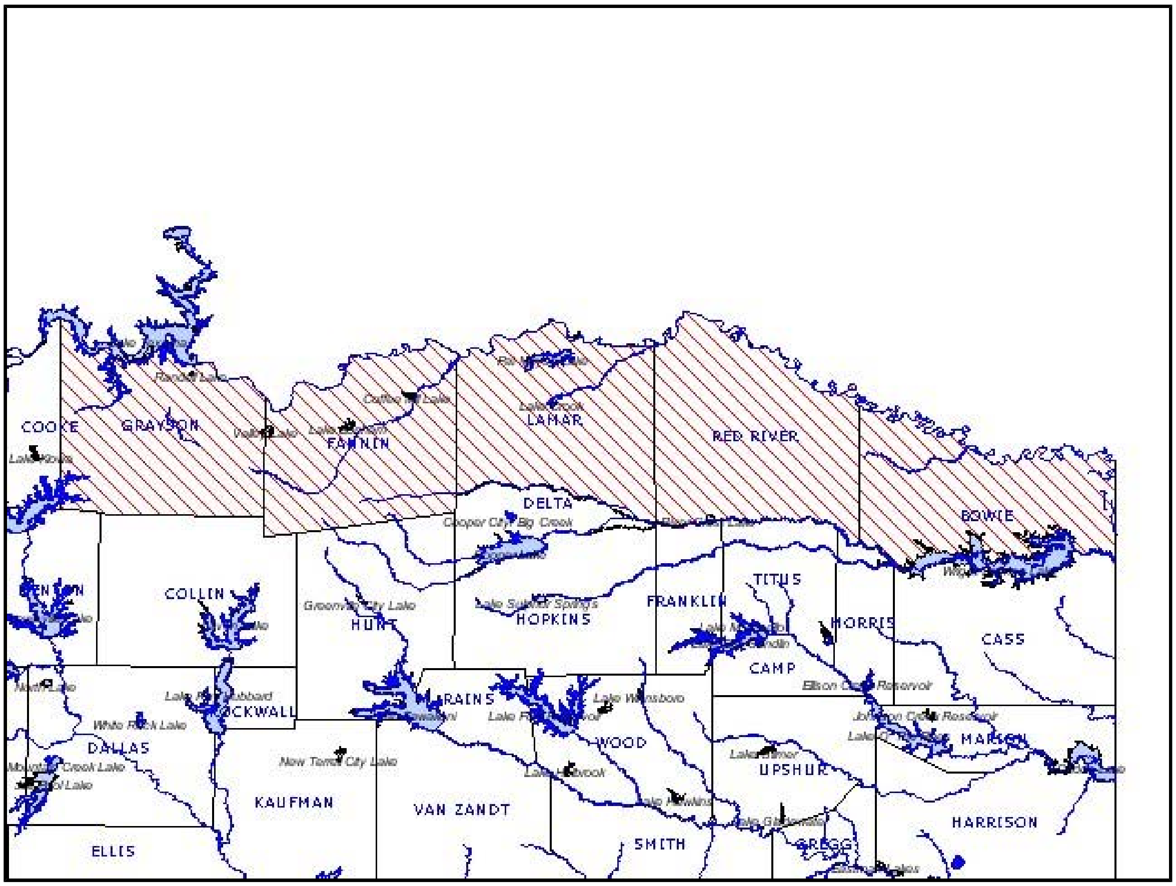
Federal Status:

State Status:

typically large rivers and streams with sluggish, turbid waters, on mud or mud-gravel bottoms; also smaller streams and reservoirs usually deep in soft mud or occasionally among rocks; quiet areas of otherwise swift streams; Red River with unsuccessful introductions into the upper Trinity River System

Revision Date: 05/12/2005

potential or known presence within county



Bowie, Fannin, Grayson, Lamar, Red River County(ies)

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Fairfield Lake State Park

123 State Park Rd 64
Fairfield TX 75840
903/389-4514

Watch video of Fairfield Lake S.P.

History: Fairfield Lake State Park is 1460 acres northeast of the City of Fairfield in Freestone County. The park was acquired in 1971 - 1972 by lease from Texas Utilities and was opened to the public in 1976.

The history of the area around Fairfield Lake State Park resembles that of much of rural eastern Texas. Long occupied by Native Americans who exploited its waterways, the land was first broken in the mid-nineteenth century and planted in cotton and corn by Anglo farmers and, about a third of the time, their African-American slaves. Following the Civil War, the crop-lien system took root. Blacks and whites alike worked in the service of the cotton crop until after World War II, when changes in American agriculture and increased employment opportunities away from the farm brought an end to the era of widespread cotton farming. Since that time, cattle ranching has prevailed throughout the region. The human population of the Brown Creek area, never large, is now widely scattered over the region. In this sparsely populated area, Texas Utilities built its dam, creating Fairfield Lake as a cooling system for its new power plant.

Activities: Activities include camping, backpacking, hiking, day use equestrian, nature study, bird watching, boating on this 2400-acre lake, water skiing, jet skiing, fishing, and lake swimming in a large, buoyed, sandy area.

Fishing: Fairfield Lake is warmed by the TXU Big Brown power plant. Because of our warm water, people come from all over Texas to enjoy some fantastic winter fishing opportunities. From November through February, we have tournaments every weekend. Fishing Clubs from the Dallas/Fort Worth, Houston, Waco, Austin, and Tyler areas host tournaments here. Why drive all the way to the Texas Gulf Coast to enjoy fishing for Red Drum! What makes Fairfield different then most lakes is that, because of the warm winter temperatures, it is stocked with Red Drum (aka Red Fish). The state record for Inland Red Drum was taken here at Fairfield Lake. (44 inches, 36.83 lbs.)

- Watch video of Fairfield Lake State Park.
- Check the Calendar for events and access restrictions scheduled within the next 3 months.
- Detailed fishing & lake information for Fairfield Lake.
- More Information on outdoor activities from the Experience Texas page.

Area Attractions: Nearby points of interest include Texas State Railroad, Fort Parker State Park; Old Fort Parker (operated by the City of Groesbeck), and Confederate Reunion Grounds State Historic Site; the Cities of Rusk, Palestine, and Fairfield (where the Freestone County Museum in the century-old jail is located). While you are in the area, visit the Texas Freshwater Fisheries Center in Athens a unique TPWD facility showcasing aquatic life and sport fishing in Texas.

Campsites & Other Facilities: There are campsites with water (most on the lakefront); campsites with water and electricity; a hike-in primitive camping area (at the end of a 6-mile, round-trip hiking trail); picnicking; an overflow camping area; restrooms with and without showers; a lighted fishing pier; a fish-cleaning shelter; a fish-cleaning table; boat ramps; a trailer dump station; playgrounds; a group dining hall for day-use only; and an amphitheater.

A six-mile trail has connected an older 9-mile trail to provide a continuous 15 miles of trailways that provide multi-use (hiking, mountain biking, and equestrian) access from one end of the park to the other. Much of the trail is adjacent to the 2400-acre Fairfield Lake. There is also a 2-mile nature trail and 1 mile of bird watching trail.

Firewood, ice and park-related merchandise can be purchased at the State Park Store. There is an honor box to collect park use fees after office hours.

- Fees
- Map of Park (PDF 132.6 KB).

Check availability/make reservations for Fairfield Lake S.P.
You can also make e-mail reservations, fax reservations or phone reservations.

Natural Features: Surrounding woods are oak, hickory, cedar, elm, dogwood, and redbud, which offer sanctuary for many species of birds, and mark the transition zone between the pine forests to the east and the prairie grasslands to the north and west. Wildlife found in the park include osprey (year-round), bald eagles (November through February), white-tailed deer, raccoons, foxes, beavers, squirrels, and armadillos. Popular catches include catfish, bass, carp, freshwater redfish, and other varieties.

More information on the wildlife mentioned here:

- Texas Wildlife Factsheets.

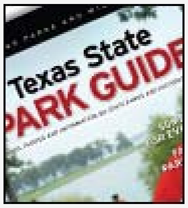
Elevation: 461 ft.
Weather: July average high is 95; January average low is 35; April and May are wettest months; first/last freeze: November 29/March 11.

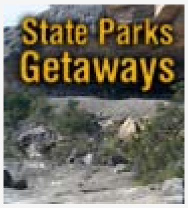
- National Weather Service forecast for this area.

Schedule: Open: 7 days a week year-round, except for Public Hunts. Check the Calendar for events and access restrictions scheduled within the next 3 months. Busy season: March through November.

Directions: The park is 6 miles northeast of Fairfield off FM 2570 on FM 3285 adjacent to Fairfield Lake. 90 miles south of the Dallas/ Fort Worth area, 150 miles north of the Houston area, and 60 miles east of Waco. The park is located just a few miles from Interstate 45, northeast of the city of Fairfield, Texas.

Current conditions including, fire bans & water levels, can vary from day to day. For more details, contact the park.





More Promotions.

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Last modified: September 16, 2008, 2:31 pm

Richland Creek WMA Public Use Links:

- Richland Creek WMA Home
- Rules
- Maps & Directions
- Activities at a Glance
  - Hunting
  - Bicycling
  - Camping
  - Equestrian
  - Fishing
  - Hiking
  - Wildlife Viewing
  - Other
- Events

Wildlife Management Area Links:

- Find a Wildlife Management Area
  - Ordered by County
  - Ordered by Name
  - Browse by Location
  - Search by Activity
    - Biking
    - Camping
    - Driving
    - Equestrian
    - Fishing
    - Hiking
    - Hunting
    - Wildlife Viewing
- Wildlife Management Area Calendar
- Required Permits

Richland Creek WMA

Phone: (903) 389-7080
Address:
1670 FM 488
Streetman, TX 75859

Contact: Matthew Symmank

Dates Open: Open year round, except closed for Special Permit hunts.

Description

The Richland Creek WMA was named for Richland Creek, a tributary to the Trinity River, which flowed through the property prior to the construction of Richland-Chambers reservoir. Richland Creek Wildlife Management Area was created to compensate for habitat losses associated with the construction of Richland-Chambers Reservoir. The Area is owned and managed by Texas Parks and Wildlife Department. The mission of RCWMA is to develop and manage populations of indigenous and migratory wildlife species and their habitats and to provide quality consumptive and non-consumptive public-use in a manner that is not detrimental to the resource.

Richland Creek Wildlife Management Area is located in an ecotone separating the Post Oak Savannah and Blackland Prairie ecological regions and the Area lies almost entirely within the Trinity River flood plane. The Area is subject to periodic and prolonged flooding. Average annual rainfall is 40 inches. Soils consist primarily of Trinity and Kaufman clays. These bottomland soils are highly productive and support a wide array of bottomland and wetland dependant wildlife and vegetation communities.

Vast bottomland hardwood forest communities characterized by cedar elm, sugarberry, and green ash dominate the area. Honey locust, boxelder, and black willow are also common. Pockets of bur oak, shumard oak, overcup oak, water oak, willow oak, and native pecan also occur. The understory is dominated by hawthorn, cat briar, poison ivy, and rattan with shade tolerant grasses and forbs comprising the herbaceous layer. Large non-forested areas also occur and are characterized by diverse herbaceous communities.

The vast bottomland hardwood forests serve as nesting and brood rearing habitat for many species of neotropical birds. The Area has numerous marshes and sloughs, which provide habitat for migrating and wintering waterfowl, wading birds and shore birds, as well as diverse aquatic life.

Please note:

- Bring your own drinking water.
- Restrooms unavailable.
- Flooding may occur during heavy rains, so be prepared to move to higher ground.
- ATV's allowed only during special permit hunts.
- Each permit holder may possess one dog while hunting waterfowl, squirrels or rabbits. Companion dogs must be leashed or confined within designated campsites.

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Last modified: August 21, 2009, 10:01 am

Big Lake Bottom WMA Public Use Links:

- Big Lake Bottom WMA Home
- Rules
- Maps & Directions
- Activities at a Glance
  - Hunting
  - Fishing
  - Wildlife Viewing

Wildlife Management Area Links:

- Find a Wildlife Management Area
  - Ordered by County
  - Ordered by Name
  - Browse by Location
  - Search by Activity
    - Biking
    - Camping
    - Driving
    - Equestrian
    - Fishing
    - Hiking
    - Hunting
    - Wildlife Viewing
- Wildlife Management Area Calendar
- Required Permits

Big Lake Bottom WMA

Phone: (903) 389-7080
Address:
1670 FM 488
Streetman, TX 75859

Contact: Jamie Killian

Dates Open: Open year round except closed for Special Permit Hunts.
Entire area closed: October 12-16, November 11-13, 16-18, and December 15-17, 2009.

Description

The Big Lake Bottom WMA is owned and operated by the Texas Parks and Wildlife Department (TPWD). The 2,870-acre management area lies adjacent to the Trinity River and is located about 10 miles southwest of Palestine in Anderson County. It was purchased by TPWD to preserve the rapidly disappearing Post Oak Savannah's bottomland hardwood habitat. Currently 2,870 acres of the area are accessible and open for public use. The management area is not totally contiguous, but fragmented by private tracts of land. It is accessible from county roads at two locations.

The topography, soil types, and vegetation of the area are representative of the Post Oak Savannah river bottoms. Soils are of poorly drained clays, common on flood plains that are unprotected from flooding. Since the terrain is flat and lies within the river's flood plain, the area is often covered by shallow slow moving floodwaters. The area is normally inaccessible several times a year for extended periods due to high water or wet soil conditions. Over 90 percent of the management area is bottomland habitat of mature hardwood timber. A systematic inventory of the management area's plant community has cataloged over 450 plant species.

Principal wildlife species found on Big Lake Bottom WMA include white-tailed deer, feral hog, ducks, mourning dove, fox squirrel, gray squirrel, bobcat, raccoon, skunk, armadillo, coyote, gray fox, and many species of reptiles and migratory birds.

Please note:

- Public use of the area is allowed during daylight hours only.
- Caution should be taken since area is often muddy or under water.
- Entry is restricted to designated entry points only.

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Gus Engeling WMA Public Use Links:

- Gus Engeling WMA Home
- Rules
- Maps & Directions
- Activities at a Glance
  - Hunting
  - Bicycling
  - Camping
  - Driving
  - Equestrian
  - Fishing
  - Hiking
  - Wildlife Viewing
- Events

Wildlife Management Area Links:

- Find a Wildlife Management Area
  - Ordered by County
  - Ordered by Name
  - Browse by Location
  - Search by Activity
    - Biking
    - Camping
    - Driving
    - Equestrian
    - Fishing
    - Hiking
    - Hunting
    - Wildlife Viewing
- Wildlife Management Area Calendar
- Required Permits

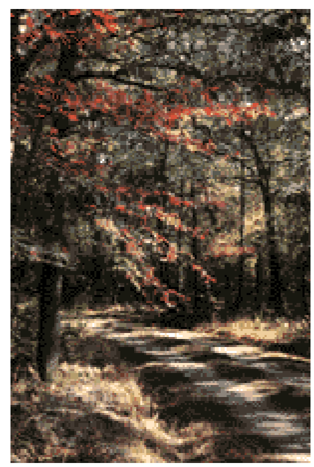
Gus Engeling WMA (GEWMA)

Phone: (903) 928-2251
Address:
16149 North US Hwy 287
Tennessee Colony, TX 75861

Contact: Wes Littrell

Dates Open: Open year round, **except area closed during special hunts.**

Description



Gus Engeling Wildlife Management Area (GEWMA) is located in northwest Anderson County, 21 miles northwest of Palestine. This 10,958 acre area was purchased from 1950 to 1960 under the Pittman-Robertson Act using Federal Aid in Wildlife Restoration Program funds. The (GEWMA)'s primary purpose is to function as a wildlife management, research and demonstration area for the Post Oak Savannah Ecoregion. The area is comprised of 2,000 acres of hardwood bottomland floodplain and almost 500 acres of natural watercourse, 350 acres of wetlands: marshes and swamps and nearly 300 acres of sphagnum moss bogs. The (GEWMA) is an island of Post Oak Savannah surrounded by coastal bermuda grass pastures, harvested timberlands, and fragmented wildlife habitat. It's rolling sandy hills dominated by post oak uplands, bottomland hardwood forests, natural springs, pitcher plant bogs, sloughs, marshes, and relict pine communities contain a rich variety of wildlife. Sound wildlife management tools like prescribed burning grazing, brush control and hunting are used to demonstrate the results of proven practices to resource managers, landowners, and other interested groups or individuals.

History:

Historically, the upland sites of the Post Oak Savannah were open and dominated by waist-high grasses and large scattered trees. In addition, early observers reported large oak "motts" or islands of continuous hardwoods scattered throughout the grassland prairie. Bottomlands were dominated by mature, massive oaks that prefer deep, rich, moist soils. Both uplands and bottomlands supported an abundance of wildlife before man's intervention. By the mid-1800's European settlement produced dramatic changes in East Texas. Timber operations, prevention of wildfires, damming of streams and rivers, and clearing of land for pasture and crops changed the land. The first barbed wire fence was constructed in 1888. Within two years most of the land had been fenced and was severely overgrazed by hogs and cattle. Hardwoods in the bottomlands were logged during these years. The trees which made the best homes for wildlife, such as large and vigorous white oaks, walnuts, and hickories, were the first taken. Although not marketable, many good wildlife trees, such as young hardwoods and old pines, were removed and replaced by loblolly pines for timber. These loblolly pines invaded the flood free bottoms below dams, reducing the numbers of hickories and oaks. Cavity dwelling wildlife, such as wood ducks, woodpeckers, raccoons, squirrels, and many other birds and mammals, found fewer homes after the loggers passed. Most cultivated land was planted in cotton at this time, with some small farms growing row crops.

The turn of the century marked the beginning of the livestock industry in this area. Most of the land was severely overgrazed by hogs and cattle for the first half of the century. In the mid-1900's, there was an increase in livestock production resulting in the clearing of large tracts of hardwoods for pasture. Livestock production continues to be the principal land use in this part of Texas. Although still called the Post Oak Savannah, this part of East Texas is now quite different from the countryside seen by the first settlers.

Most of the land comprising the GEWMA was purchased by the then Texas Game, Fish and Oyster Commission between 1950 and 1960. Much of this land was purchased from Milze L. Derden, hence the original name Derden Wildlife Management Area. The GEWMA was purchased under the Pittman-Robertson Act as a wildlife research and demonstration area for the Post Oak Savannah Ecoregion where trained personnel could study wildlife management practices.

The area was renamed in 1952 after Gus A. Engeling, the first biologist assigned to the area, was shot and killed by a poacher on December 13, 1951.

The GEWMA has not suffered from man's presence as much as most of the Post Oak Savannah. Although the land was used for livestock for many years, it was not extensively cleared. Mature bottomland forests still dominate Catfish Creek. Five hundred acres of post oak uplands have nearly been returned to its original Post Oak Savannah state through 35 years of prescribed burning.

Goals:

The initial goal and intended purpose of the Gus Engeling WMA was to serve as a wildlife research and demonstration area where trained biologists could study and evaluate wildlife and habitat management practices. Around 1990 the majority of staff duties shifted from research to public use activities and development. Future activities will return to research and demonstration designed to benefit people interested in wildlife management in the Post Oak Savannah.

In 1989, the following goals were adopted by the Wildlife Division and are used as guidelines for preparing WMA management plans. The goals are listed in priority order.

- To develop and manage wildlife habitats and populations of indigenous wildlife species.
- To provide a site where research of wildlife populations and habitat can be conducted under controlled conditions.

- To provide areas to demonstrate habitat development and wildlife management practices to landowners and other interested groups.
- To provide natural environments for use by educational groups, naturalists, and other professional biological investigators.
- To protect populations of endangered or threatened migratory wildlife, plant species, related habitats, unique natural sites and relic vegetation communities.
- To provide public hunting and appreciative use of wildlife in a manner compatible with the resource.

Natural Resources - Flora/Fauna:

The GEWMA is representative of the Post Oak Savannah Ecoregion which encompasses approximately 13,300 square miles of Texas reaching from Red River County in the northeast to Guadalupe County in the south. Upland soils are generally light-colored, deep, rapidly permeable sands and sandy loams. Bottomland soils are mostly mixed alluvial clays and clay loams, gray brown in color and moderately permeable. Topography is gently rolling to hilly with a well-defined drainage system that empties into Catfish Creek which is a tributary of the Trinity River. Eight miles of Catfish Creek have been designated as a "Natural National Landmark" by the US Department of the Interior. The drainage system encompasses approximately 2,000 acres of bottomland. Average annual rainfall is approximately 40 inches. Generally, rainfall is fairly evenly distributed throughout the year with less occurring during July and August.

Vegetation present in the uplands includes a dense overstory of oak, hickory, elm, and gum with a shade tolerant understory of flowering dogwood, American beautyberry, greenbriar, farkleberry, yaupon, possumhaw, dewberry, and hawthorn. Common grasses include little bluestem, broomsedge bluestem, slender Indiangrass, purpletop, beaked panicum, and spike uniola. Some dominant forbs include tickclover, wildbean, goldenrod, and doveweed. Oak trees, mostly water and willow oak, are the dominant tree species in the bottomlands. Common wetland plants include yellow lotus, common duckweed, sedges, rushes, pondweed, giant cutgrass, and plumegrass. Depending on rainfall and weather conditions, spring displays of flowering dogwood and wildflowers can be spectacular.

Between 1860 and 1920, year-round hunting with no bag limits greatly reduced the deer and turkey number. From 1948 to 1950, 280 white-tailed deer, 128 Rio Grande turkey, and 13 beavers were released on the area. The deer population steadily increased resulting in the opening of a deer season in 1955. This population remains healthy and provides a major source of recreation. Beavers are now abundant and have created many acres of wetlands on the GEWMA and surrounding lands. Wild turkeys did not prosper; so several more releases were made. The result was a small, unstable population of hybrids between pen-raised Eastern gobblers and Rio Grande hens. More recently, releases were made in 1988, 1995 and 1996. The first Eastern wild turkey hunt was held in 2003.

The GEWMA has a rich variety of wildlife. Currently 37 mammals, 156 birds, 54 reptiles and amphibians, 57 fishes and 900 plant species have been documented. There's no guarantee, but the observant visitor may see white-tailed deer, Eastern wild turkey, gray squirrels, fox squirrels, raccoons, beavers, wood ducks, or pileated woodpeckers just to name a few.

Cultural Resources:

The stewardship role of TPWD staff regarding archeological resources and historic resources is defined in the Antiquities Code of Texas (Title 9, Chapter 191 of the Texas Natural Resources Code of 1977), which calls for the location and protection of all archeological sites owned by the State of Texas. Any violation of the terms of the Antiquities Code is a criminal act, punishable by a fine and/or jail term.

Research Activities:

One of the principle goals of the Gus Engeling Wildlife Management Area is to provide a site where research of wildlife populations and habitat may be conducted under controlled conditions. Through such studies biologists hope to gain a better understanding of the interrelationships between native wildlife species, domestic livestock, and habitat resources. This will enable biologists to make recommendations for a sound multiple-use management program tailored to the Post Oak Savannah region of Texas. As of 1997, 35 approved research projects have been conducted on the Engeling WMA involving such topics as:

- White-tailed deer aging techniques
- Factors affecting white-tailed deer fawn survival
- Comparisons of feeding habits between white-tailed deer and cattle
- Site-specific competition between feral hogs and white-tailed deer
- Primitive weapon hunting techniques
- Effects of selective clearing on wildlife habitat
- Quail population responses to habitat manipulation
- Controlled burning to improve woodland habitat for wildlife

Current projects are investigating the usefulness of feral hog control measures in aiding nesting success of Eastern turkeys and conducting a complete vegetation analysis and Geographical Information System (GIS) mapping of the entire Area.

Recreational Opportunities :

Anglers and hunters interested in waterfowl and small game need only possess an APH Permit and valid fishing or hunting license to gain access on designated days during the appropriate season. Deer hunters, both archery and gun, are randomly selected during the Special Permit drawing to avoid over harvesting of the resource.

Visitors may enjoy nature viewing, bird watching, photography, hiking, camping and the general beauty of nature. Botanists and wildflower enthusiasts may revel in the dazzling spring and fall displays. The GEWMA also serves as an outdoor laboratory for local colleges, universities, elementary, and secondary schools.

A self-guided auto tour takes a visitor through 10 stops which address wildlife, habitat and management techniques. In addition, the Beaver Pond Nature Trail and Dogwood Nature trail offer visitors the chance to personally experience the lush green mysteries of East Texas. But be warned, all four varieties of venomous snakes occur in this area - so please watch your step. Visitors seventeen years of age and older must posses either an **Annual Public Hunting (APH) Permit** or **Limited Public Use (LPU) Permit** to utilize the WMA (no permit required for the driving tour and nature trails). These permits are available at all license sale locations in Texas or by calling **1-800 TXLIC4U**

(895-4248). Permits are not for sale at the WMA. Refer to Outdoor Recreational Opportunities on WMAs for additional information about opportunities on the Gus Engeling WMA.

Please note:

- **All users must perform on-site daily registration.**
- Bring your own drinking water.
- The wildlife observation blind and the restrooms are wheelchair accessible.
- Walking in the bog area is prohibited.
- Insecticide and sunscreen are advised.
- Alligators inhabit some areas and should be considered dangerous.

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Stephen F. Austin State Park

Skip Links

- History
- Activities
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- Campsites & Other Facilities
  - Fees
  - Facility Map
    (PDF 113.1 KB)
    Trails Map
    (PDF 265.2 KB)
- Natural Features
- Schedule & Directions

Check Availability / Make Reservations for Stephen F. Austin S.P.
You can also make E-mail Reservations, Fax Reservations or Phone Reservations

Other Nearby TPWD Destinations:

- San Jacinto Battleground
- San Jacinto Monument
- Battleship *TEXAS*

Parks & Historic Sites - Anchor Links:

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- Historic Sites
- Park Reservations
- Campsites, Lodging & Facilities
- Park Maps
- Activities for all Parks
- Calendar of Events for all Parks
- Special Promotions & Events

Stephen F. Austin State Park

P O Box 125
San Felipe TX 77473-0125
979/885-3613

History: Stephen F. Austin State Park, in Austin County, was deeded by the San Felipe de Austin Corporation in 1940, and the park was opened to the public the same year.

The park is located on the Brazos River, near the old ferry site and a part of the Commercio Plaza de San Felipe, just a few miles from the site of the township of San Felipe, the seat of government of the Anglo-American colonies in Texas. It was here Stephen F. Austin, the "Father of Texas," brought the first 297 families to colonize Texas under a contract with the Mexican Government. From 1824 to 1836, San Felipe de Austin was the social, economic, and political center, as well as the capital of the American colonies in Texas. Due to the many historic events that occurred here, the community acquired the reputation "Cradle of the Texas Liberty." Also, the conventions of 1832 and 1833 and the Consultation of 1835 were held here. These meetings eventually led to the Texas Declaration of Independence. San Felipe was the home of Austin and other famous early Texans; the home of Texas' first Anglo newspaper (The Texas Gazette, founded in 1829); the home of the postal system of Texas origination and the setting for the beginning of the Texas Rangers.

Activities: Nestled on the banks of the Brazos River, Stephen F. Austin State Park provides the opportunity to get up close to nature. Located just 30 minutes from the outskirts of Houston, this quiet and peaceful park is a nice escape from the busy city life. Several species of flora and fauna call the park home, and many are visible with just a car ride through.

Activities include picnicking, camping, fishing, hiking, and nature and historical tours. Currently you can fish without a license at all Texas State Parks during the "Free Fishing in State Parks" promotion.

Educational Program & Hiking Tour Schedule:

- Feature Park
- Volunteer, Concession, & Employment Information
- Wi-Fi at Parks
- Rules & Regulations
- Texas State Parks Pass

Saturday Afternoon/Evening: Programs on various topics pertaining to the park. All ages welcome to this family program
Sunday Mornings: Nature Hike for Kids. All ages welcome, targeted for 13 and under
Contact park office for more details and specific schedules.
Groups(4 or more): Contact Interpretive Ranger to schedule group hikes and programs.

- **Check the Calendar for events and access restrictions scheduled within the next 3 months**.
- **More Information on outdoor activities from the Experience Texas page**.

Volunteer Information:

- **Friends of Stephen F. Austin State Park -** Make a difference! Donate or volunteer to help our park stay beautiful. Every dollar helps and we have a wide variety of jobs that you can come out and help us with, including mowing, litter pickup, trail repair, and camp hosting. For more info, contact the park office. Thanks for your support!
- **Go to the Volunteer Opportunities page** for information on the many volunteering options available at State Parks & Historic Sites.

Area Attractions: Nearby points of interest include the San Jacinto Battleground Complex including the **San Jacinto Battleground**, **San Jacinto Monument**, and the **Battleship *TEXAS***; **San Felipe State Historic Site** and Houston, the largest city in Texas, with numerous attractions including: Hermann Park Zoo, the Museum of Natural Science, and NASA.

Campsites & Other Facilities: Come out for just a day and enjoy the many hiking and biking trails, or spend the night at one of the 3 types of campsites. The park also offers group facilities, for day or overnight use. Park facilities include: 40 full hook-up campsites with water, electricity, and sewer, 20 screened shelters with electricity and water, 40 water only campsites, a group dining hall, a group recreation hall that is available for day or ovenight use, and a spacious picnic area. Be sure and visit our **Texas State Park Store** for gifts and supplies.

- **Fees**
- **Map of Park** (**PDF** 113.1 KB)
- **Trails Map** (**PDF** 265.2 KB)

Natural Features: Stephen F. Austin is home to several habitats, including, wetland, aquatic, and hardwood forest. A towering canopy of a wide variety of trees will shade you from the hot sun. Time your visit and you will see the beautiful blooms of the plentiful wildflowers. For the birders, come see the nesting Pileated Woodpeckers, as well as many other species. Bird lists are available upon request. Deer, raccoons, opossum, and armadillos are common sightings. And finally, if the creepy crawlies are the animals you like, there are many types of reptiles and amphibians to be seen here. Fishing is also available, after a short hike to the Brazos, with catfish being the most common catch.

More information on the wildlife mentioned here:

- Texas Wildlife Factsheets.

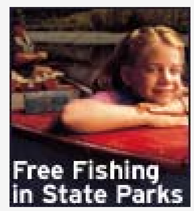
Schedule: Open 7 days a week year-round. Busy Season: March through May; October through November. Check the Calendar for events and access restrictions scheduled within the next 3 months.

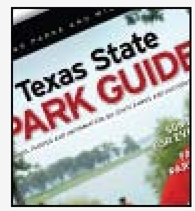
Elevation: 155 ft.
Weather: Average annual rainfall 40.4; average January minimum 43; average July maximum 94.

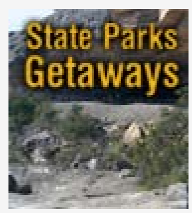
- National Weather Service forecast for this area.

Directions: From Houston, travel west on Interstate 10 to FM 1458 (just before Sealy). Turn right (north) on FM 1458 and then left on Park Road 38.

Current conditions including, fire bans & water levels, can vary from day to day. For more details, contact the park.







More Promotions.

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Brazos Bend State Park

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- Activities
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  - Calendar of Events
- Facilities
  - Fees
  - Map of Facilities
    (PDF 144.3 KB)
  - Map of Trails
    (PDF 534.8 KB)
- Natural Features
- Schedule & Directions

Check Availability / Make Reservations On-line for Brazos Bend SP
You can also make E-mail Reservations, Fax Reservations or Phone Reservations

Other Nearby T.P.W.D. Destinations:

- Galveston Island State Park
- Stephen F. Austin State Park
- Lake Texana State Park
- Battleship TEXAS State Historic Site
- San Jacinto Battleground State Historic Site
- Sheldon Lake State Park
- Washington-on-the Brazos State Historic Site

Parks & Historic Sites - Anchor Links:

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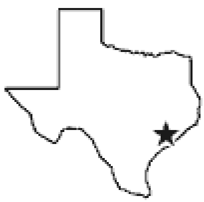
- Find a Park
- Historic Sites
- Park Reservations

Brazos Bend State Park

21901 FM 762
Needville TX 77461
979/553-5102



Watch video of Brazos Bend S.P.

Texas Outdoor Family workshop **will be held at this park on Saturday - Sunday, April 10-11, 2010.**

History: Brazos Bend State Park, approximately 28 miles southwest of Houston, covers roughly 5000 acres, with an eastern boundary of 3.2 miles fronting on the Brazos River on the southeast border of Fort Bend County. This was the area of Texas' first Anglo colonization. It was purchased by the state in 1976-77 and was opened to the public in 1984.

Archeological materials show that prehistoric people visited this area, possibly as early as 300 BC; in early historical times, the Capoque band of the Karankawa Indians roamed between the mouth of the Brazos River and Galveston Bay and may have traveled inland as far as Brazos Bend. In the early 19th century, this area of Texas was the site of Stephen F. Austin's first colonial land grant from Mexico, and present park land was included in a grant to Abner Harris and a partner named William Barrett in 1827. Most of riverfront was sold shortly after the Texas Revolution, and

- Campsites, Lodging & Facilities
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records show that in 1845, part of the park and 2400 feet of river frontage were in the hands of cotton brokers who lived in Brazoria. At the time, the Brazos River was one of the principal routes of commerce, and it may be that the brokerage firm used the area for one of its riverboat landings. In recent times, the land on which the park is located was used for cattle grazing, pecan harvesting, and as a private hunting preserve.

- Interpretive Guide to Brazos Bend State Park (PDF 739.1 KB)

Activities: Activities include camping, picnicking, hiking, biking, equestrian, and fishing. Six lakes are easily accessible to fishermen, with piers located at 40-Acre, Elm and Hale Lakes. Visitors are cautioned to pay due respect to alligators, which are numerous in some areas of the park. There are at least three free interpretive programs and hikes offered every weekend. Interpretive staff and volunteers offer weekday guided hikes and programs for schools and other educational organizations. Fees and reservations required. The Nature Center is open Monday - Friday from 11 a.m - 3 p.m. and Sat & Sunday from 9 a.m to 5 p.m. It's "Habitats and Niches" display offers an unusual "hands-on" alligator discovery area, a tactile model of the park, freshwater aquarium, live native snake species, a touch table and an open-captioned orientation video for all visitors including those with hearing impairments. The George Observatory is located in the park and is open Saturdays from 3 p.m. to 10 p.m. For information on stargazing programs/passes and other programs, call the Observatory at 979/553-3400 or at 281/242-3055 (as a satellite of the Houston Museum of Natural Science) or visit the George Observatory web site. Shop for gifts at the headquarters gift shop, the Visitor Center, and at the George Observatory.

Creekfield Lake Nature Trail is an accessible nature trail and interpretive exhibit pilot project is the first of its kind for the department (1995) and was designed with the assistance of the greater Houston area disabled community in partnership with The George Foundation, Fort Bend County, and the United States Fish and Wildlife Service. The trail is fully paved and takes visitor on a .5 mile loop our of an outstanding wetland area. Exciting features along this trail include a series of interpretive panels with tactile bronzes of wetland wildlife, and accessible boardwalk and observation deck for wildlife viewing, rest areas with shaded benches, A self-guided manual and scavenger hunt is available at Park Headquarters and Nature Center or from the volunteer web site.

Hike and Bike/Foot Trials: Hike and bike trails are located around 40-Acre, Elm and Hale Lakes and interconnect. Alligator viewing is best from the 40-Acre and Elm Lake Trail system. Foot trials take you off the beaten path into the hardwood forest. Always take plenty of water with you for you and your pets. As with all state parks, Pets are allowed on leash only and leash can be no longer than six feet. Do not allow pets to drink from or enter the water. Know your Alligator Etiquette found on park maps and posted throughout the park. An Outdoor Guidebook will assist you in learning about the parks different ecosystems and outdoor safety. The guidebook is available on the volunteer web site or for sale only at the Nature Center Gift Shop.

- Watch video of Brazos Bend State Park.
- Check the Calendar for events and access restrictions scheduled within the next 3 months.
- Fishing Tip Sheet for Brazos Bend State Park. (PDF 126.2 KB)
- Brazos Bend State Park Information Guide. (PDF 132.5 KB)

- **Read about a new minor planet "Brazos Bend" discovered through telescopes located inside the park at the George Observatory**.
- **More Information on outdoor activities from the Experience Texas page**.

Volunteer: The **Brazos Bend State Park Volunteer Organization** is one of the largest in Texas State Parks and has been incorporated since 1989. This hands-on group assists with park maintenance and interpretive activities. It operates the Nature Center and its own gift shop. Training is offered in February and September. For information about being a Brazos Bend Park Host contact the park. **More information on Volunteer and Park Host opportunities at Texas State Parks**.

Area Attractions: Nearby are the **San Jacinto Battleground**, **San Jacinto Monument**, and the **Battleship *TEXAS***; **Galveston Island State Park**; Brazoria County Access Point (San Luis Pass County Park); **Sea Center Texas** in Lake Jackson; the George Ranch; Houston's attractions; and West Columbia, which was founded in 1826 and served as the Capital of the Texas Republic for a brief period in 1836. It is the site of **Varner-Hogg Plantation State Historic Site** and is approximately 25 miles south of Brazos Bend.

Facilities: Facilities include restrooms with showers; campsites with water and electricity; screened shelters; primitive **equestrian** campsites; a trailer dump station; a dining hall (capacity 150), with ceiling fans, ac/heat, kitchen facilities, a barbecue pit, tables and chairs, and a restroom; approximately 35 miles of hiking/biking trails, including 8 miles of equestrian trails and a .5-mile nature/interpretive trail. For day-use visitors, there are 3 separate picnic areas with picnic sites. Two picnic areas have a group picnic pavilion (capacity 75 each): Elm Lake and Hale Lake pavilions, have electricity and water outlets, a barbecue pit, and picnic tables.

Be sure & visit the Texas State Park Store for great gifts & supplies.

The park has a Headquarters Gift Shop that offers a wide variety of souvenirs, nature books and gifts that will enhance and enrich visitors' experience ba. is open daily: Sun. 7am-5pm, M-Th 8am-5pm, Fri-Sat 7am-10pm.

- **Fees**
- **Map of Facilities** (**PDF** 144.3 KB)
- **Map of Trails** (**PDF** 534.8 KB)

Check availability/make reservations on-line for Brazos Bend SP
You can also make **e-mail reservations**, **fax reservations** or **phone reservations**

Natural Features: Most of the park is in the Brazos River floodplains, but there are also areas of flat upland coastal prairies. Numerous swales and

depressions become freshwater marshes during periods of heavy rain. In addition to the Brazos River, Big Creek meanders diagonally across the park and is associated with sloughs and cutoff meanders called oxbow lakes. Other lakes have been created by levees. The creek and riverbanks are lined with sycamore, cottonwood, and black willow. Campsites and picnicking areas are located among huge, moss-draped live oaks; while trails run along the lakes and through bottomland hardwood forests.

Nature lovers, birders, campers, and other outdoor enthusiasts will delight in an observation tower and platforms for wildlife observation/photography of more than 300 species of birds sighted; 21 species of reptiles and amphibians, including American alligator; 17 species of mammals including bobcat, white-tailed deer, raccoon, and gray fox; 39 species of dragonfly; 500 species of plants.

- United States Geological Survey Fort Bend County Butterfly Checklist.
- Birds of Brazos Bend State Park: A Field Checklist (PDF 293 KB)

More information on the wildlife mentioned here:

- Texas Wildlife Factsheets.

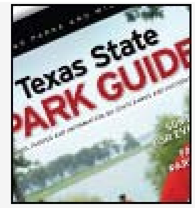
Elevation: 104 feet
Weather: January minimum 41 degrees and July maximum is 94 degrees, average rainfall 43.9.

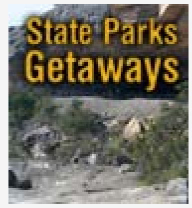
- National Weather Service forecast for this area.

Schedule: The park is open 7 days a week year-round except when closed for emergencies or scheduled closures. **Gate Hours:** Friday, Saturday and Sunday the park opens at 7am. Monday through Thursday the park opens at 8am. The gate is closed at 10pm each night. Check the Calendar for events and access restrictions scheduled within the next 3 months.

Directions: The park is approximately a one-hour drive from downtown Houston. Take Highway 59 South to the Crabb River Road exit. You may also take State Highway 288 south to FM 1462 West. Follow FM 1462 to FM 762 North. From the south follow State Highway 288 North to the FM 1462 exit or take State Highway 36 to FM 1462 East. All routes are marked with brown signs to guide you.

Current conditions including, fire bans & water levels, can vary from day to day. For more details, contact the park.





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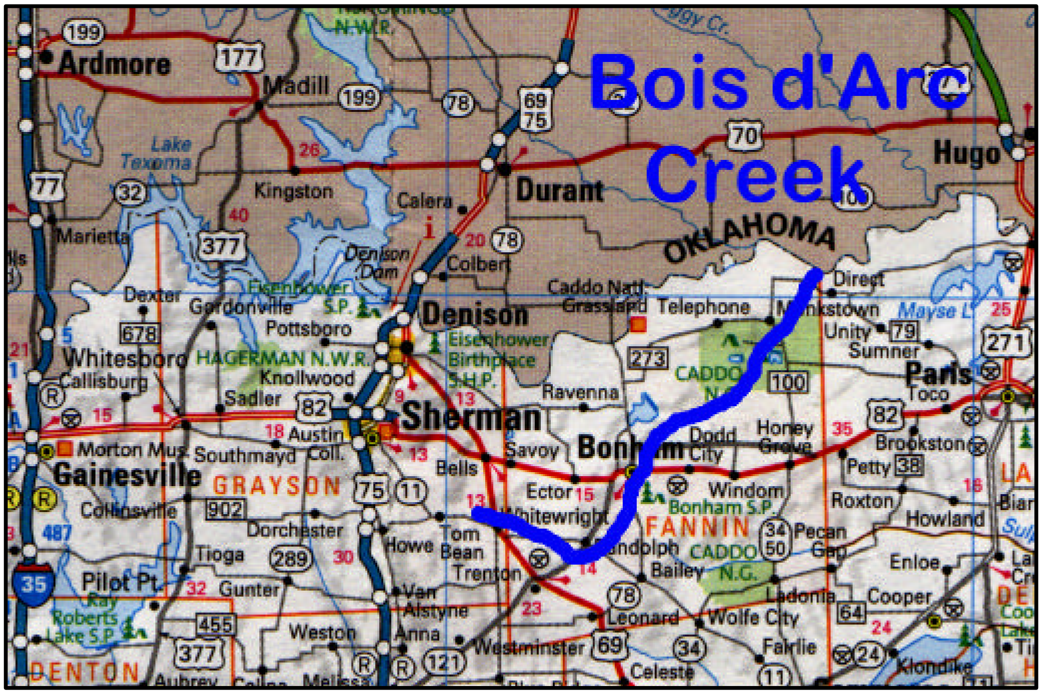

Adapted from Texas Map. Gulf Publishing, 1998.

Figure 2. Map Location of Bois d'Arc Creek

Figure 2. Bois d' Arc Creek north of FM 409

Bois d’Arc Creek

Bois d’Arc Creek begins about 6 miles southwest of Savoy in the eastern part of Grayson County and flows northeasterly approximately 50 miles into the Red River near the city of Direct (TPWD, 1998). The creek is one of the major drainages of the Red River in Texas. It transects the Oak Woodlands region of Texas near the confluence with the Red River and the Blackland Prairie region of Texas throughout the rest of its course. The USFWS (1985) has identified 3,911 acres of forest adjacent to Bois d’Arc Creek as being priority bottomland hardwood forest due to high habitat resource value. The bottomland forest provides habitat for white-tail deer, squirrels, turkeys, raptors, colonial waterbirds, and other migratory birds. The creek generally runs clear over a predominantly sandy substrate and supports a diverse assemblage of fish species (Belisle, 1974). A survey conducted in 1982 found over 20 species of fish, including spotted gar, common carp, river carpsucker, channel catfish, golden shiner, smallmouth buffalo, red shiner, largemouth bass, white crappie, freshwater drum, western mosquitofish, and several sunfish species (Bayer et al., 1992). The candidate segment is from the confluence with the Red River in Fannin County upstream to its headwaters in Eastern Grayson County.

(1) Biological Function- displays significant overall habitat value considering the high degree of biodiversity (USFWS, 1985).
(2) Hydrologic Function- bottomland hardwood forest provides valuable hydrologic function relating to water quality and flood control.
(3) Riparian Conservation Area- fringed by the Caddo National Grasslands.

Adapted from USGS Sherman, Texas. Original Scale 1: 250,000.

Figure 10. Map Location of Coffee Mill Creek

Figure 11. Coffee Mill Creek east of FM 2029

Coffee Mill Creek

Coffee Mill Creek begins about 12 miles north of Bonham in Fannin County and flows easterly 11 miles into Bois d'Arc Creek, which is a tributary to the Red River (TPWD, 1998). The creek transects the Caddo National Grasslands and is within the Blackland Prairies natural region of Texas. The Caddo National Grasslands were purchased by the federal government in the late 1930's and have been managed by the United States Department of Agriculture since 1970 (TPWD, 2000). Coffee Mill Creek feeds Coffee Mill Lake, which is one of three lakes within the Caddo National Grasslands. The lake offers camping, boating, and fishing opportunities, while the grasslands and adjacent waterbodies have been recognized by Field and Stream Magazine as a Texas hunting and fishing destination for largemouth bass and white-tail deer (TPWD, 2000). The candidate segment is from the confluence with Bois d'Arc Creek in Fannin County upstream to its headwaters.

Riparian Conservation Area- fringed by the Caddo National Grasslands.

Ecologically Significant River and Stream Segments

For assistance with accessibility on any TPWD documents, please contact accessibility@tpwd.state.tx.us

Brazos River

Figure 12. Map Location of Brazos River

Adapted from Texas Map. Gulf Publishing, 1998

Figure 13. (a) The Brazos River north of State Highway 35 and (b) the diamondback terrapin


(a)


(b)

Brazos River

The Brazos River is one of two major rivers in Texas that empties into the Gulf of Mexico through an undredged mouth. This results in a deltaic environment that provides excellent habitat for shorebirds. Extensive bottomland hardwood forests that line the banks of the Brazos and associated marshes provide habitat for a wide variety of bird species throughout the year including numerous heron and egret species, barred owls, purple gallinules, least bitterns, and prothonotary warblers. Other inhabitants include American alligators, bobcats, white-tailed deer, raccoons, gray foxes, and feral hogs. The river itself provides habitat for gar, catfish, crappie, and freshwater drum among other fish species. The ecologically significant segment is from the confluence with the Gulf of Mexico in Brazoria County upstream to FM 529 in Austin/Waller County. This is part of TNRCC stream segments 1201 and 1202.

(1) Hydrological Function- performs valuable hydrologic functions relating to flood attenuation, water quality, and groundwater recharge of the Chicot Aquifer.[20]

(2) Riparian Conservation Area- fringed by Brazos Bend State Park and Stephen F. Austin State Park and is part of the Great Texas Coastal Birding Trail.

(3) Threatened or Endangered Species/Unique Communities- significant due to presence of rare live oak-water oak-pecan bottomlands[1] and Diamondback terrapin.[13]

(back)

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Ecologically Significant River and Stream Segments

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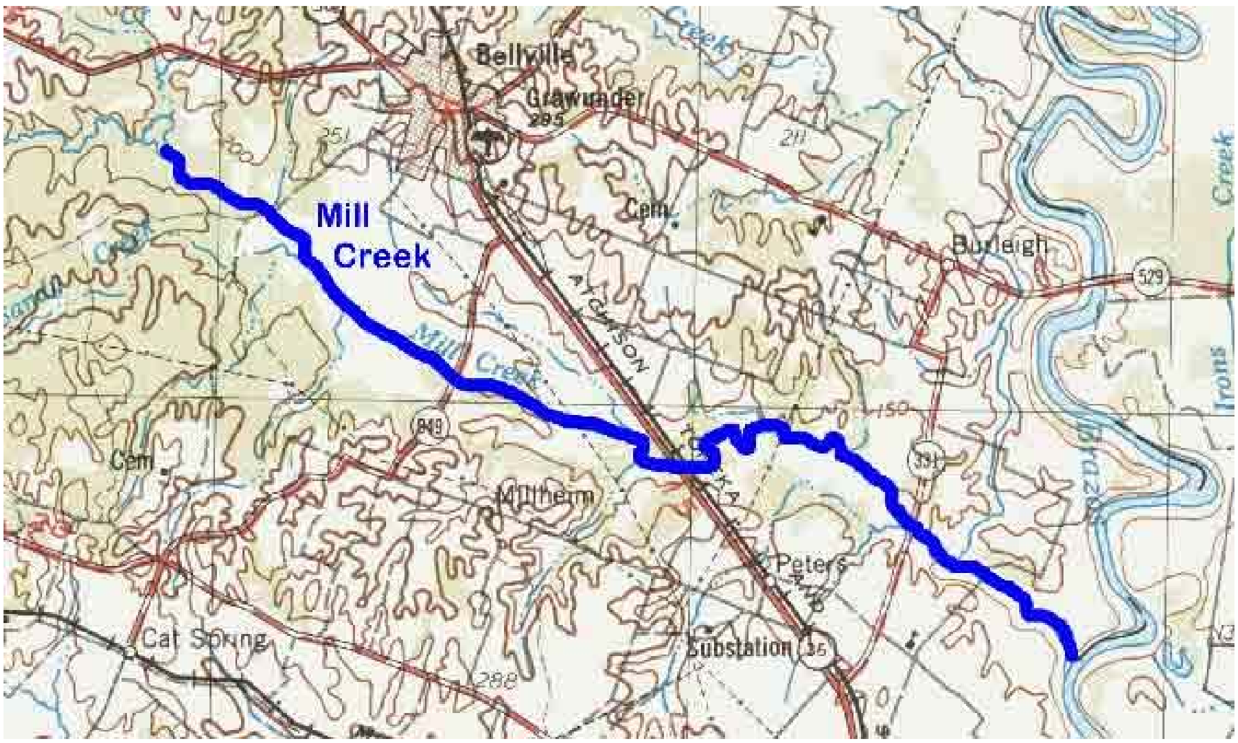
Mill Creek

Figure 38. Map Location of Mill Creek



Adapted from USGS Seguin, Texas. 1975. Original scale 1:250,000.

Figure 39. Mill Creek west of FM 331

Mill Creek

Mill Creek forms west of Bellville where West Mill and East Mill Creek's join in southern Washington County and flows southeasterly across Austin County to the Brazos River northeast of Sealy. The creek's channel is narrow and shallow with a sandy substrate and numerous sandbars. The creek follows a meandering path through interspersed pasture land and hardwood forest floodplain and provides habitat for a diverse fish community including spotted gars, minnows, common carp, river carpsuckers, channel catfish, and several sunfish species.[11] The surrounding area is known as the Katy Prairie and is one of the country's premier wintering waterfowl regions despite virtually all of the grassland having been converted to rice fields. The rice fields act as artificial wetlands that attract migrant shorebirds such as the American golden-plover, Hudsonian godwit, pectoral sandpiper and the buff-breasted sandpiper. The bottomland forest that surrounds much of the creek provides habitat for numerous woodland birds such as wrens, sparrows, vireos, warblers and Eastern bluebirds. The ecologically significant segment is from the confluence with the Brazos River upstream to the point where it is formed by West Mill and East Mill Creeks.

(1) Biological Function- high biodiversity that displays significant overall habitat value.[11,16]

(2) Hydrologic Function- performs valuable hydrologic functions relating to water quality and groundwater recharge of the Chicot Aquifer.[20]

(3) High Water Quality/Exceptional Aquatic Life/High Aesthetic Value- identified as an Ecoregion Reference Stream by the TPWD River Studies Program due to high dissolved oxygen and biodiversity of benthic macroinvertebrates.[2]

(4) Threatened or Endangered Species/Unique Communities- rare gammagrass-switchgrass bottomland tallgrass prairie.[1]

(Back)

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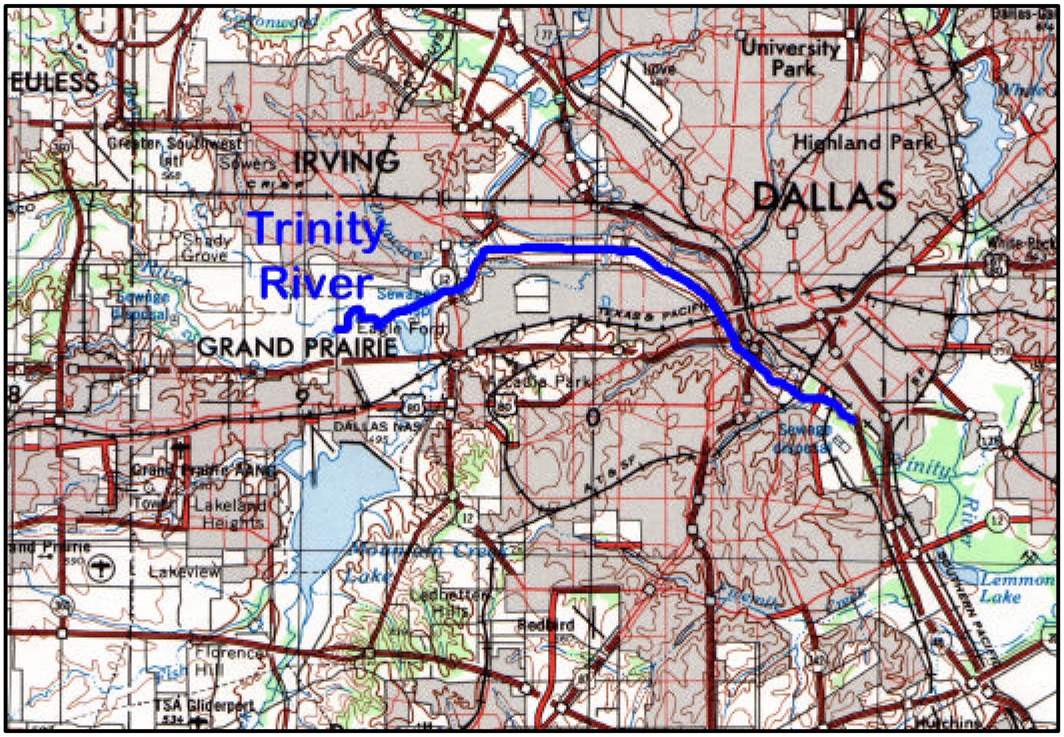
Last modified: June 16, 2008, 2:28 pm



Adapted from USGS Dallas, Texas. Original Scale 1: 250,000.

Figure 20. Map Location of the Trinity River

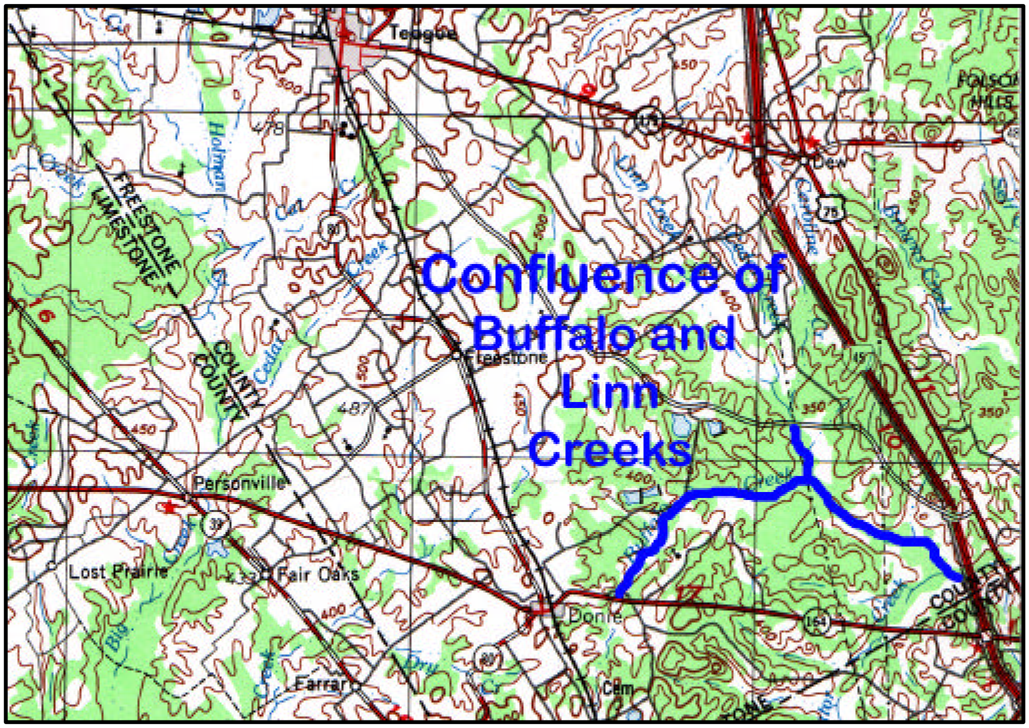
Figure 21. Trinity River west of Westmoreland Road

Trinity River

The Trinity River is formed in the northern part of the state in Dallas County by the union of several headwater tributaries and flows southeasterly 455 miles into Trinity Bay near Anahuac in Chambers County (TPWD, 1998). The candidate segment is from Interstate Highway 45 in Dallas County upstream to MacArthur Boulevard in Dallas County (within TNRCC stream segments 0805 and 0841).

(1) Riparian Conservation Area- fringed by the Trinity River Greenbelt Park.

(2) High Water Quality/Exceptional Aquatic Life/High Aesthetic Value- high and intermediate (as opposed to exceptional) aquatic life use (TNRCC, 1995).



Adapted from USGS Waco, Texas. Original Scale 1: 250,000.

Figure 6. Map Location of the confluence of Buffalo and Linn Creeks

Figure 7. Linn Creek south of CR 691

Buffalo and Linn Creek Confluence

Buffalo and Linn creeks originate in the southwest corner of Freestone County. Linn Creek flows southeasterly about seven miles where it joins Buffalo Creek. Buffalo Creek flows southeasterly 30 miles into Upper Keechi Creek, which is a tributary to the Trinity River (TPWD, 1998). The confluence of the two creeks is within the Oak Woods and Prairies region of Texas (TPWD, 2000). The USFWS (1985) has identified 532 acres within the confluence of these two streams as being priority bottomland hardwood forest. The area is primarily old growth bottomland and old growth upland forest. The bottomland forest consists primarily of water oak, Eastern hop hornbeam, American elm, winged elm, sugarberry, and pecan; whereas the upland forest is composed primarily of post oak, black hickory, and winged elm (USFWS, 1985). This area of bottomland forest is considered one of the highest quality bottomlands in existence and has only a small amount of disturbed wetland and willow swamp associated with it. It also has high value to mammals such as white-tail deer, furbearers, and squirrels, as well as to migratory birds (USFWS, 1985). The candidate segment of Buffalo Creek is from the confluence with Alligator Creek upstream to State Route 164. The candidate segment of Linn Creek is from the confluence with Buffalo Creek upstream to County Road 691.

(1) Biological Function- priority bottomland hardwood habitat displays significant overall habitat value (USFWS, 1985).
(2) Hydrologic Function- bottomland hardwood forest provides valuable hydrologic function relating to water quality and flood control.

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Surface Mining & Reclamation

Turlington Mine Pending Projects

Updated: February 2, 2010

This listing provides the current status of permitting actions requested by the permittee for consideration by the Commission.

200831203	**TM New Permit Application - 10,397 Ac**	**11/07/2008**
Project Type:	New Permit Application	*Examiner:*
Mine/Permit:	Turlington Mine - Proposed	Spraggins, Marcy J.
Reviewer:	Haney, Liz	*Docket#*
Last Event:	Busted Deadline Letter - 01/29/2010	C9-0008-SC-00-A

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RENEWABLE ENERGY PROGRAM

Renewable Energy The Infinite Power of Texas

Texas Solar Energy

I'd put my money on the sun and solar energy. What a source of power! I hope we don't have to wait until oil and coal run out before we tackle that. - Thomas Edison, in conversation with Henry Ford and Harvey Firestone, 1931

Jump to: **Photovoltaic Energy** | **Solar Incentives** | **Connecting to the Grid** | **Netmetering** | **Renewable Portfolio Standard**

Solar power is friendly to our environment because no fuels are combusted, which means that emissions associated with generating electricity from solar technologies are negligible. The most common technologies used to actively convert solar energy into electricity are **photovoltaics** and **concentrating solar power** (solar-thermal) which include **parabolic trough** systems, the lowest cost solar electric option for large power plant applications. Unlike solar photovoltaic, solar thermal projects tend to be large-scale and in remote areas. See this **video** of a concentrating solar power plant.

It is DOE's goal to install 1,000 megawatts (MW) of new concentrating solar power systems in the southwestern United States, including Texas, by 2010. See the **Southwest Concentrating Solar Power 1000-MW Initiative**.

Though we can capture solar energy, concentrate it, store it and convert it into other useful forms of energy, solar technologies must be further developed and profitably marketed to successfully harness the sun's power on a large commercial scale and to provide cost-effective, reliable energy services. **NREL** collaborates with industry to further the research and development of concentrating solar power (CSP) plant and solar thermal technologies and supports DOE in its concentrating solar power deployment efforts.

In it's ***2008 Annual Energy Outlook***, The U.S. Department of Energy's Energy Information Administration projected thermal power generation to increase more than fourfold by 2030, while grid-connected solar power, which provided a miniscule share of the country's power in 2006, is projected to experience a 73-fold increase.

Enter Our Solar Portal!
See the real-time performance data from solar electric systems we've supported throughout our great Lone Star state.

Maplewood Elementary School, Austin ISD

City Programs
Land and Water Needs
Active and Passive Solar Energy
Texas Renewable Energy Resource Assessment

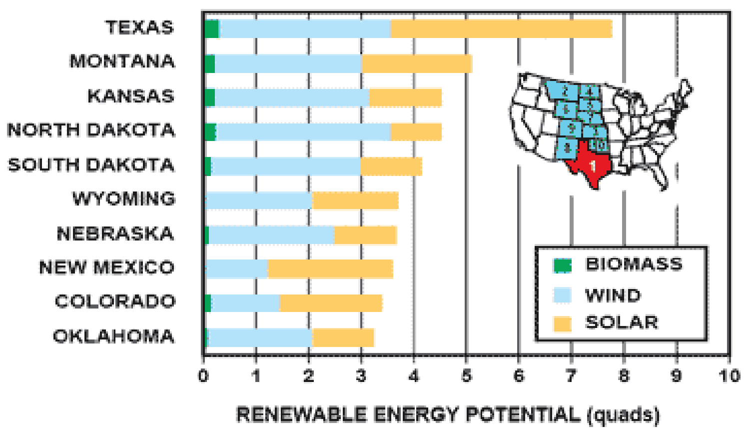
Solar Radiation in Texas

Texas has a virtually unlimited solar energy supply, ranking first in the nation in solar resource potential, with high levels of direct solar radiation. suitable to support large-scale solar power plants. concentrated in West Texas, which has 75 percent more direct solar radiation than East Texas, making it an ideal location for utility-scale concentrating solar power (CSP) technologies.

The Solar Energy Laboratory at the University of Texas at Austin emphasizes research on solar radiation measurements at several sites across Texas compiled as the **Texas Solar Radiation Data Base**. The database information includes monthly solar radiation averages for these locations. Also see this solar radiation data with **average BTU's output per day** for 8 Texas cities, provided by Thermo Technologies.

Texas is one of seven states partnering with DOE and the Western Governors Association to install concentrating solar power (CSP) systems. The program's overall goal is to install 1,000 megawatts (MW) of new CSP systems in the southwestern United States by 2010. For additional information, see the DOE National Renewable Energy Laboratory (NREL) web site, **Southwest Concentrating Solar Power 1000-MW Initiative**.

Texas is Exceptional in Solar Energy Potential!



The energy from sunshine falling on a single acre of land in West Texas is capable of producing the energy equivalent of 800 barrels of oil each year.

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City Solar Programs

Austin Energy
Austin Energy is an Austin community-owned electric utility with a comprehensive energy efficiency program. Austin Energy provides energy conservation information for both homes and businesses, equipment purchasing guidelines and conservation ideas, and rebates and low-interest loans to help residential and business customers make energy efficiency improvements. After Austin's rebate and **federal tax credits**, an average 3 kilowatt residential solar system on an 1800 square foot house costs about $7000. If the solar system is financed, savings on the electric bill are greater than the monthly payments on your loan, which means you save money from day one. see Austin Energy's **solar rebate program**, **net metering program**, and **interconnection guidelines**.

Final Report of the Texas RE-Connect Project
This report was provided by Austin Energy under a grant from the U.S. Department of Energy. The report, "*Interconnection and Net Metering of Small Renewable Energy Generators in Texas,*" provides information on how Texas electric utilities handle requests to interconnect and net meter small renewable energy generating systems in the hope that such information-sharing would encourage more consistent approaches statewide.

Austin's Solar City Partnership Recognition
Austin was one of 13 Solar America Cities 2007, recognized by DOE's Solar Energy Technologies Program. Austin City's solar goals are to:

- increase solar installation visibility;
- develop school energy curricular materials;

- install solar energy systems in local schools;
- educate teachers and students about solar energy;
- assess rooftop areas suitable for solar development;
- work with local non-profits to promote solar, energy efficiency and green building programs; and
- reduce barriers that prevent participation in renewable energy and energy conservation programs.

El Paso Solar Energy Association (EPSEA)
EPSEA furthers solar energy and related technologies with concern for the ecological, social and economic fabric of the region (West Texas, Southern New Mexico, Northern Mexico). In addition to monthly meetings and seminars, EPSEA conducts technology demonstrations and project development work related to renewable energy technologies in the Southwest U. S. and Northern Mexico. EPSEA publishes a monthly newsletter on solar energy and EPSEA activities.

Solar San Antonio (SSA)
Solar San Antonio is a leading advocate of sustainable communities and facilities powered by renewable energies. SSA initiates meetings, educational events, and outreach opportunities that increase awareness of the benefits of a green, clean and sustainable economy.

DOE Designates San Antonia as a Solar America City *March 2008*
The U.S. Department of Energy (DOE) announced its selection of 12 cities including San Antonio, Texas, as Solar America Cities. Each city will receive $200,000 (a total of $2.4 million) to integrate a variety of solar technologies, such as solar water heating, solar photovoltaic electric systems, and large-scale solar thermal electric systems, which are also known as concentrating solar power. Combined with industry cost sharing and funding from each city, the total amount invested will be approximately $12.1 million. In addition to the funding, DOE will also provide hands-on assistance from technical experts to help cities integrate solar technologies into their energy planning, zoning, and facilities; streamline local regulations and practices that affect solar adoption; provide solar financing options; and promote solar technology among residents and local businesses through outreach, curriculum development, and incentive programs.

Austin Designated Solar America City *June 2007*
DOE will award nearly $2.5 million to 13 cities, including Austin, to increase the use of solar power across the country. DOE will also provide hands-on assistance from technical and policy experts to help the cities integrate solar technologies into city energy planning, zoning and facilities and to streamline city-level regulations and practices that affect solar adoption by residents and local businesses. Selected cities demonstrated a level of commitment to promote solar throughout the city, involving local government officials, utilities and private partners. Cities were selected competitively. Austin participants include Austin Energy, Texas Solar Energy Society, Clean Energy Associates, and local school districts. See the **awards overview**.

Distributed Generation in Texas
A Texas Public Utilities Commission web page with all the policies that are in place)

List of Distributed Generation Contact Persons in the Texas Utilities

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Active & Passive Solar Energy

Solar energy is the most democratic of renewable energy resources. It is available everywhere on the earth in quantities that vary only modestly. Only a very small percentage of the sun's energy strikes the earth but that is still enough to provide all our energy needs. Solar energy can be **active** (direct) or **passive** (indirect).

Active

Active photovoltaic solar systems collect, store and convert the sun's energy either as photovoltaic (PV) electricity or thermal (heating) energy.

Inside collector panels, air or water circulates, directing the sun's heat to a direct use for electric power, or a heat storage device. Typical uses for active solar collection systems are space and water heating.

Passive

Passive solar design uses the sun's energy for the heating and cooling of living spaces, making use of building materials and building siting to take advantage of the sun's heat and light without using mechanical means.

In this approach, the building itself or some element of it takes advantage of natural energy characteristics in materials and air created by exposure to the sun. Passive systems are simple, have few moving parts, and require minimal maintenance and require no mechanical systems.

Land & Water Needs for Solar Power

Solar radiation has a low energy density relative to other common energy sources, so it requires that a large total acreage be utilized to gather an appreciable amount of energy. While the construction of large facilities like solar power plants are within the realm of successfully implemented projects, their size requires that a host of social and environmental issues be considered.

Typical solar-to-electric power plants require 5 to 10 acres for every megawatt (MW) of generating capacity. A 200 MW solar plant in West Texas would need about 1,300 acres of land.

Solar thermal electric technologies typically require considerable water supplies. While the quantity of water needed per acre of use is similar to or less than that needed for irrigated agriculture, dependability of the water supply is an important issue in the sunny, dry areas of the state favored for large-scale solar power plants.

Solar Two thermal power demonstration, 1995-1999

Photovoltaic systems do not require the use of water to create electricity; and though solar-thermal technologies may tap local water resources, the water can be re-used after it has been condensed from steam back into water. Systems offering this flexibility sometimes are called distributed power generators. By contrast, utility-scale concentrating solar power plants use centralized power plants and transmission lines to distribute electricity to customers.

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Texas Renewable Energy Resource Assessment

In the mid-1990's, the State Energy Conservation Office (SECO) performed a study to evaluate Texas's renewable energy resource base, including solar, wind, biomass, water and geothermal. The following chart is included in the study, **Texas Renewable Energy Resource Assessment**. One of the main efforts of this project was to estimate the size of each of Texas' renewable energy resources.

The 2007 Texas Legislature directed SECO to update the 1995 assessment of Texas renewable energy resources. This report, which will be released before the start of the 2009 Texas legislative session, will include up-to-date data on the availability of various renewable energy resources.

Figure 1: The total physical energy for each resource is the amount available within the entire state per year. The accessible resource is the amount of the total resource that is technically feasible to extract with existing or near-term technology. Energy density compares the relative concentration of the resources at a prime Texas location for each. Measurement units are in quads per year. For reference, one quad is enough to serve all annual energy needs for about 3,000,000 people. Clearly then, the 4,300 quads of solar energy incident on the state each year is an immense resource.

Figure 1. Quantification of Texas Renewable Energy Resource Base and Identification of Primary Uses

RESOURCE	TOTAL PHYSICAL RESOURCE (quads/yr)	ACCESSIBLE RESOURCE (quads/yr)	ENERGY DENSITY: GOOD TEXAS SITE (MJ/m2/yr)	PRIMARY ENERGY USES				NON-ENERGY USES
				ELEC	HEAT	MECH	TRANS	
SOLAR	**4,300**	**250**	**8,000**	**Y**	**Y**			
WIND	12	4	15,000	Y		Y		
BIOMASS	13	3	45	Y	Y		Y	Food feed fiber
WATER	3	1	10	Y	Y	Y		Water supply; flood

								control
GEO-THERMAL	1 (2,300,000 quads)	1	3	Y	Y			
BUILDING CLIMA-TOLOGY	0.6	.26	430	Y	Y			
ELEC = electricity, MECH = mechanical, TRANS = transportation, Y = Yes								

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SECO | STATE ENERGY CONSERVATION OFFICE

Texas Wind Energy

The U.S. has had the fastest growing wind power capacity in the world for the last three years in a row. This is a trend we are proud of and we intend to continue supporting its advance. Secretary Samuel W. Bodman, DOE 2008

Jump to: **Small Wind Systems** | **Incentives** | **Transmission** | **Wind Storage** | **Cash Crop** | **Renewable Portfolio Standard** | **Take a Tour** | **Connecting to the Grid** | **Net Metering**

For centuries, people have harnessed the wind's energy to grind grains, pump water, run sawmills, propel boats and generate electricity for homes. Due to advanced technology, government incentives, high fuel prices and environmental concerns, the U.S. has been the fastest growing wind power market in the world for the past three years, according to the 2007 DOE report, ***Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends***. Wind energy becoming a significant contributor to national electrical power. In 2007, wind projects nationally accounted for 35 percent of all new electric generating capacity and transmission facilities capable of generating over 200 GW of wind power are in the early stages of development throughout the nation.

Installed Wind Capacity

We are eager to continue the trend of increasing the use of wind power at unprecedented rates. Andy Karsner, DOE Assistant Secretary 2008

The U.S. wind industry grew by 45 percent in 2007, and over half of that growth was contributed by Texas. Texas is the leading wind state in the U.S., accounting for close to one-third of the nation's total installed wind capacity, which is the equivalent of the electricity needed to power more than one million Texas homes. A single megawatt of wind energy can produce as much energy used by about 230 typical Texas homes in a year.

For a wind energy overview, see the ***Wind Energy Overview*** in the Texas Comptroller's 2008 energy report.

Roping the Texas Breezes

Sound economic principles are driving wind energy development in Texas. The fact that wind energy is clean, reliable and inexhaustible is icing on the cake. Jerry Patterson, Texas General Land Office Commissioner

Immense wind turbines are becoming a familiar sight, silhouetted against Texas skies. Wind power development in Texas has more than quadrupled since the **Renewable Portfolio Standard** was established in 1999. Wind resource areas in the Texas Panhandle, along the Gulf Coast south of Galveston, and in the mountain passes and ridge tops of the Trans-Pecos offer Texas some of the greatest wind power potential in the United States, with consistently high wind speeds capable of sustaining a productive wind farm.

Texas holds the record for the world's largest **wind farm**, Horse Hollow Wind Energy Center. In addition, the Sweetwater wind farm more than doubled in capacity to 585 megawatts, pushing it from fifth to second place in the size rankings, while the state's

Buffalo Gap wind facility expanded to 353 megawatts, placing it in fifth place for size. The recently completed 364-megawatt Capricorn Ridge wind facility, also in Texas, landed in fourth place. The largest new Texas facility is the 209-MW Roscoe Wind Farm, located about 50 miles west of Abilene. See current and proposed **Texas Wind Projects**.

Roscoe wind farm

Roscoe Wind Farm among cotton fields, by Lisa Nelwak for the Roscoe Wind Council

The Horse Hollow Wind Energy Center in Texas remains the largest wind farm in the world with a total capacity of 735 megawatts (MW) spread across approximately 47,000 acres in Taylor and Nolan counties near Abilene in west central Texas. The wind plant consists of 291 1.5-MW wind turbines from General Electric and 130 2.3-MW wind turbines from Siemens. One MW of electricity can serve 230 Texas homes on average each day.

Source: FPL Energy: Horse Hollow wind farm

Wind Energy Transmission

In Texas the demand for additional wind power has grown so rapidly that the Texas electric transmission grid has a critical need for expansion. In 2006, Texas Governor Rick Perry announced commitments of $10 billion from private companies to increase wind generating capacity in the state by 7,000 megawatts, contingent on the Texas Public Utility Commission (PUC) approving construction of additional transmission capacity to windy areas of the state.

In July 2007, the Texas Public Utility Commission announced its approval for additional transmission lines that could deliver as much as 25,000 megawatts of wind energy from remote areas in the state to urban centers by 2012, depending on how many wind farms are built. New transmission infrastructure will allow all Texans to access the the state's vast wind resources. The Electricity Reliability Council of Texas (ERCOT) has identified ed more than 17,000 MW of possible wind energy projects. See the **wind energy transmission** web page for additional information.

Wind Power Costs

Electric utilities have shown an increased interest in wind project ownership, and wind industry sales to power marketers have become more common. Wind power has consistently remained at or below the average price of conventional electricity such as coal, nuclear, and natural gas. Wind power costs per kilowatt-hour have decreased over the past two decades, though prices have fluctuated in the past three years. DOE estimates that prices may increase in the next year. Expense involves various factors:

- wind strength
- average wind speed and variability
- location
- physical geography,

- wind turbine type and size
- site development cost
- installation cost
- state regulations
- wind farm size
- financing costs
- land leases and royalties costs

Environmental Impact

This record-shattering year of wind additions shows that wind power is already one of the most important, emission-free sources of energy being deployed to address climate change and improve our energy security. Andy Karsner, DOE Assistant Secretary 2008

Power generated by the wind is called a clean source of electricity because its production does not produce pollution or greenhouse gases. The use of wind power for our energy needs displaces approximately 23 million tons of carbon dioxide (the leading greenhouse gas) each year, which would otherwise be emitted by other energy sources. Furthermore, wind projects use no water in the generation of electricity.

There are other environmental impacts that do cause concerns such as the noise produced by the rotor blades, aesthetic (visual) impacts, and the danger that birds may fly into the rotors. Most of these problems have been resolved or greatly reduced through technological development or by properly siting wind power plants. if Asked, the Texas Parks and Wildlife Department will review a wind energy project against a draft set of guidelines for wildlife protection.

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Texas Wind Power Classification

Estimates of wind resources are expressed in wind power classes ranging from class 1 to class 7, with each class representing a range of mean wind power density or equivalent mean speed at specified heights above the ground. Class 4 winds or greater are suitable with advanced wind turbine technology under development today. Class 3 areas may be suitable for future technology. Class 2 areas are marginal and class 1 areas are unsuitable for wind energy development..

The following map depicts the various wind energy classifications found in Texas. An area's wind resource potential is expressed in wind power classes ranging from class 1 to class 7, with each class representing a range of mean wind power density or equivalent mean speed at specified heights above the ground.

Texas wind classification map

Source: Alternative Energy Institute, West Texas A&M University

Currently there are over 2,000 wind turbines in West Texas alone, most of them on land leased from farmers and ranchers. These wind farms range from 2,000 acres to more than 100,000 acres, which may involve several landowners. Most of the new wind capacity added in the last two years has been in the Abilene-Sweetwater area.

Though wind farms cover many acres, the wind turbines take up a comparatively small space of one or two acres each, with plenty of room between them to avoid air turbulence that can impede airflow. When placing and spacing the turbines, wind developers take into account the terrain, and the direction of the prevailing winds. We often see turbines lined up along hilltops and mountain ridges because the higher the turbine can reach, the stronger is the wind current that is available to generate increased power. Windy areas are also found in wide-open areas such as open plains and shorelines.

Small Wind Systems
Texas wind is also being harnessed for **small wind systems** to provide on-site electricity and working power for ranches, homes and businesses at increasingly competitive costs. Because new technology has created wind turbines that can now generate power from lower wind speeds, land that was previously unsuitable for wind turbines offers a new source of wind energy. Lower requisite wind speeds also allow for turbines to be placed closer to the homes and businesses that need to make use of them. Additionally, many rural landowners, farmers and ranchers are leasing their lands to wind companies for additional income.

Wind Turbine Research and Testing Facility
In June 2007, Texas was selected by the U.S. Department of Energy to be home to a large-scale wind turbine research and testing facility, accelerating the commercial availability of wind energy. Blade testing is required to meet wind turbine design standards, reduce machine cost, and reduce the technical and financial risk of deploying mass-produced wind turbine models. The Lone Star Wind Alliance, a Texas-led coalition of universities, government agencies and corporate partners, was created to prepare the proposal for submission to the federal government. The Alliance includes the State Energy Conservation Office (SECO). A site location just north of Corpus Christi at Ingleside on the Bay was chosen because of its access to the Gulf of Mexico. The University of Houston will design, construct and operate the facility on a 22-acre site. BP has donated the land and $250,000 for the project. The facilities are expected to be operational in 2009. See the press releases by **Senator Hutchinson** and the **General Land Office**.

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Texas Permanent School Fund

Texas has historically been dependent upon oil and gas. But oil and gas won't last forever. It's vital that the Land Office finds new ways to earn money for the Permanent School Fund. Jerry Patterson, Texas General Land Office Commissioner

Publicly owned lands have played a crucial role in Texas' economic development. From the grants made to early settlers and railroad companies, to the acres generating billions of dollars in oil and gas royalties for public schools, state-owned lands have been an economic asset that few states can match.

Texas schools earn millions on wind generated on state land, depending on how many megawatts are produced and the current price of electricity. Texas schools benefit from the increase in wind farms, because like oil and gas production on state lands, wind farms on state lands are required to pay land usage fees plus a portion of revenues to the State's Permanent School Fund, which is constitutionally dedicated to the schoolchildren of Texas.

The wind industry is creating thousands of jobs and millions of dollars in royalty income for landowners, for communities and for the Texas Permanent School Fund. From only one wind farm located on state land in West Texas (Texas Wind Power Project), the Permanent School Fund has earned more than $750,000 since installation in 1995. The project is expected to earn more than $3 million for state schools and create $300 million in increased economic activity over the 25-year lease period.

State Lands for Wind Power Development

The **Texas General Land Office (GLO)** manages state lands and mineral-right properties totaling 20.3 million acres. Since 2001, the GLO has been evaluating state lands for wind power development potential through a grant from the State Energy Conservation Office (SECO), on upland and offshore sites.

The analysis of information gathered from towers installed on state lands provides an information base for wind development companies interested in leasing state lands. The GLO has identified six counties that have good potential for wind power development. Maps of these properties can be viewed **here**. Developers worldwide may submit proposals for leasing Texas state lands. For more information, contact Bob Blumberg at **bob.blumberg@glo.state.tx.us** or 512/463-5028.

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Wind Power for Texas Cities

Austin Energy

In 2005 the City of Austin's municipally owned electric utility, Austin Energy, won the Wind Power Pioneer Award from the U.S. Department of Energy for its leadership and innovation in its wind power program. Austin Energy, buys wind-generated electricity under 10-year, fixed-price contracts. The purchased power is delivered over the statewide electric grid to Austin. Austin Energy is also planning on using night time wind power to charge plug-in hybrid car batteries for day time use. See this **article** on

Austin's hybrid car program.

City of Houston
A contract negotiated in July 2007 by Houston officials ensures that a third of the city's power would be generated by wind turbines. The City of Houston paid approximately $150 million last year on electricity at $91 per 1,000 kilowatt hours. The City Council overwhelmingly passed the $628 million wind-power plan and electricity contract extension. The deal makes Houston a leader among governments nationwide for using wind sources to get power.

Perdenales and Bandera Electric Cooperatives
Both of these cooperatives offer their members renewable energy from wind.

Texas Offshore Windfall

Because of Sam Houston's foresight we now have the regulatory authority to move forward with less federal red tape. Who would have thought that the hero of San Jacinto would help bring wind energy to Texas? Jerry Patterson, Texas General Land Office Commissioner

After establishing independence from Mexico in 1836, Sam Houston, the president of the sovereign Republic of Texas, had the foresight to declare for Texas' future generations sovereignty over all lands in the Gulf Coast out to 10.4 miles, the traditional marker under international law. When Texas joined the United States, the new state's boundaries were not immediately challenged by the federal government, which recognized a three-mile boundary for other coastal states. In 1948, the U.S. attorney general filed suit to claim offshore lands more than three miles but less than three marine leagues from Texas' shoreline. For almost two decades, Texas fought to keep its tidelands intact, which had become a valuable source of oil and gas. In 1953, Congress finally recognized Texas' ownership of the tidelands, which was upheld by a U.S. Supreme Court decision in 1960. For this reason, there is only one entity in Texas for an offshore wind developer to deal with - the Texas General Land Office (GLO).

Thanks to Sam Houston's foresight, the Texas Permanent School Fund has the potential to earn millions of dollars from offshore wind generation in the Gulf of Mexico. Offshore wind farms would be only about eight miles from the electric grid, which would minimize transmission expenses. The state has leased 11,355 acres off the coast of Galveston for a 50-turbine wind farm. The Galveston Island project will produce a minimum of $26.5 million in royalties over the course of the 30-year lease.

The GLO can also lease land off the coast of Padre Island for wind farms. Leasing out this land will earn Texas schools anywhere from $34 million to more than $100 million, depending on how many megawatts are produced and the future price of electricity. Additionally, development within the offshore 10.4 miles offers proximity to the state's electrical grid to carry wind-generated power to customers.

OFFSHORE WIND RESOURE MAPS

Validated onshore wind resource maps have helped accelerate the development of wind energy in many parts of the country. AWS Truewind has provided wind resource modeling for off-shore Gulf of Mexico areas of Texas through a cost-share project between SECO and the National Renewable Energy Lab (NREL). NREL also plans to use this data to analyze the off-shore wind shear plus other wind characteristics for turbine design and performance.

- Offshore Texas, Mean Annual Wind Speed at 10 meters
- Offshore Texas, Mean Annual Wind Speed at 30 meters
- Offshore Texas, Mean Annual Wind Speed at 50 meters
- Offshore Texas, Mean Annual Wind Speed at 90 meters
- Offshore Texas, Mean Annual Wind Speed at 150 meters
- Offshore Texas, Mean Annual Wind Speed at 300 meters
- Offshore Texas, Mean Annual Wind Power Density at 50 meters

For an interactive map of planned offshore wind farms in North America, see **OffshoreWind.net**. The web site includes answers to questions on offshore wind.

South Texas Offshore Wind Farm Nixed *June 2007*

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Tour Texas Wind Farms

Wind Power Trail
Ongoing, Self-paced Tours
The Texas Wind Power Trail is a SECO-sponsored effort to familiarize Texans with working wind farms in their state. The trail takes you to commercial wind farms, vintage windmill collections, and interesting waypoints along the highways and back roads of Texas and Oklahoma with the aid of an interpretive driving map and an audio CD and an informational web side. **tour map**

American Wind Power Center & Museum
The American Wind Power Center in Lubbock is the most comprehensive collection of historic windmills in the world. It will be a site long remembered and is our way of honoring those early settlers who struggled with difficult conditions tempered with the life-giving water pumped by windmills. The newest addition to the museum is the 160-foot tall Vestas Model V47 wind turbine. It supplies immediate power to the museum and 60 surrounding homes. **Tours**

Trent Mesa Wind Farm Virtual Tour
(Windows Media, 2 minutes 23 seconds)
This web site gives detailed information on the Trent Mesa wind farm project, including a virtual tour that is entertaining and educational. The Trent Wind Farm, also known as the Trent Mesa Wind Project, is a 150-megawatt (150,000-kilowatt) wind power plant located between Abilene and Sweetwater in West Texas. The project uses 100 turbines each rated at 1.5 megawatts (1,500 kilowatts).

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Wind Energy Transmission

Great wind isn't really a great resource unless you have access to market. Sean Middleton, Illinois Rural Electric Co-operative.

Jump to: **Overview** | **Small Wind Systems** | **Incentives** | **Wind Storage** | **Cash Crop** | **Renewable Portfolio Standard** | **Take a Tour** | **Connecting to the Grid** | **Net Metering**

Electric power is generated at power plants and then moved to substations by transmission lines-large, high-voltage power lines. This network of transmission lines is known as the "grid." Texas currently leads the nation in wind development, and the Texas electric transmission grid has a critical need for expansion. Wind energy production in remote areas of the state has jumped dramatically over the past few years, putting heavy demands on the transmission systems that deliver electricity from the best resource locations in remote areas to where it will be used in urban areas.

The greatest challenge facing the wind industry is that wind farms can be built more quickly than transmission lines. It can take a year to build a wind farm, but five to build the transmission lines needed to send power to cities. Wind power developers are reluctant to build where transmission lines do not yet exist; and utilities are equally reluctant to install transmission in areas that do not yet have power generators. Senate Bill 20 attempts to solve this dilemma with long-term planning that will meet the state's transmission needs into the 21st century by providing for electricity transmission to wind-rich areas ahead of wind farm development.

In 2006, Texas Governor Rick Perry announced commitments of $10 billion from private companies to increase wind generating capacity in the state by 7,000 megawatts, contingent on the Texas Public Utility Commission (PUC) approving construction of additional transmission capacity to windy areas of the state.

In 2007, the PUC announced its approval for additional transmission lines that could deliver 10,000 more megawatts of renewable power by 2012. New transmission infrastructure will allow all Texans to access the the state's vast wind resources.

Texas Transmission Plan - Senate Bill 20

This new goal is the next step toward Texas realizing its potential to be the nation's leading producer of renewable energy. Wind power, in particular, will play a major role in meeting our future energy needs. Tom "Smitty" Smith, Director, Public Citizen

The most significant barrier to wind energy development in the Panhandle and parts of West Texas has been the lack of adequate transmission. Although Senate Bill 7 established the State's goal for renewable energy in 1999, it made no special provisions for transmission to interconnect renewable resources. With the rapid growth of the state's wind industry, Texas adopted proactive transmission planning as part of legislative strategy. Significant progress has been made with **Senate Bill 20** (SB 20), which laid the groundwork for large transmission lines in order to accommodate present wind industry needs and to further accelerate the use of wind power in the state.

Our future wind power transmission and distribution systems must be safe, secure, reliable, and cost effective. This factor presents a significant challenge to the ultimate effectiveness of the Texas **Renewable Portfolio Standard (RPS)**. In order to effectively increase and implement the RPS goals, SB 20 includes a transmission plan for remote regions such as McCamey in West Texas that are handicapped by lack of sufficient transmission infrastructure, the goal being to increase transmission capacity to get clean energy (especially wind) from remote areas of the state to the cities.

Competitive Renewable Energy Zones (CREZ)

"While many states are talking about ways to bring more clean energy to customers and improve air quality, Texas is doing it." Mike Sloan, Managing Consultant of The Wind Coalition

CREZ is a SB 20 mechanism meant to get transmission out to prime wind energy areas before wind farms have even been developed. To ensure that sufficient transmission infrastructure exists to meet the state's goal for renewable energy SB 20 requires that CREZs be designated in the best areas in the state and that an electric transmission infrastructure be constructed to move renewable energy from those zones to markets where people use energy.

As manager of the State's largest power grid, the Electric Reliability Council of Texas (**ERCOT**) was designated to collect wind data and nominate a number of CREZs based on transmission cost calculations for each CREZ. The important factors in determining the desirability of an area for wind development are the quality of the wind and the availability of transmission service in the area. In December 2006, ERCOT published a comprehensive report, ***Analysis of Transmission Alternatives for Competitive Renewable Energy Zones in Texas***, which identified the geographic areas that the PUC could designate as CREZs under Texas law.

In July 2007, after evaluating the potential for wind-generation in about 25 areas in the state, the Texas Public Utility Commission (PUC) designated eight areas as CREZs, which were combined into five zones in the areas around McCamey in Uptown County, Abilene and Sweetwater, and the Panhandle. The the PUC's interim final order outlines four scenarios for building transmission from 10,000 MW to 22,806 MW, depending on cost and the number of wind farms that are built.

In April 2008, ERCOT published it's ***Competitive Renewable Energy Zones Transmission Optimization Study***, which provides transmission plans for four scenarios of wind generation. The estimated cost of building new transmission lines to transport wind generated electricity from West and Northwest Texas to urban areas will cost about $1.5 million per mile.

PUC's final order is expected in 2008, and will designate final transmission solutions for the CREZ areas and announce the transmission companies chosen to build the transmission lines.

CREZ Maps
To see CREZ maps, go to this **PowerPoint presentation** by Dan Woodfin, Manager of Regional Planning for ERCOT. He discusses the ERCOT CREZ study. Also see this **Wind Coalition web site** for additional information, and a **downloadable map**.

ERCOT is now in the process of analyzing issues such as support needs, stability analyses, optimization of the on-ramps to accommodate new generation within the CREZs, and analysis of the specific projects or operational procedures needed to mitigate curtailments of existing wind generation. Once the CREZs are finalized, the construction of the necessary transmission facilities between the CREZ and urban areas will begin.

ERCOT estimates that building transmission lines to transport wind-generated electricity from West and Northwest Texas to urban areas will cost about $1.5 million per mile. According to the Governor's office, construction of the lines will cost an estimated several hundred million dollars over a five to seven year period, which will be paid for by all consumers across the Texas grid.

2007 Federal Rule for Transmission Access

We must harness the power of technology to help us deliver electricity more efficiently. It's time for this country to build a modern electricity grid so we can protect American families and businesses from damaging power outages. President George W. Bush 2005

In February 2007, the Federal Energy Regulatory Commission made a final ruling, ***Preventing Undue Discrimination and Preference in Transmission Service***, to allow greater access to transmission lines for power generators of all types, including renewable energy projects. The new rule exempts intermittent power generators, such as wind power plants, from excessive "imbalance" charges when the amount of energy they deliver is different than the amount of energy they are scheduled to deliver. To help accommodate less predictable forms of renewable power generation, the rule creates a "conditional firm" service to deliver power from a generator to a customer, allowing the power supplier to provide firm service for most, but not all, hours in the requested time period.

A key aspect of the new rule is that it eliminates the broad discretion that transmission providers currently possess in calculating the unused, available capacity on their transmission lines. Instead, the new rule requires public utilities to work with the North American Reliability Corporation to develop consistent methods of calculating the available capacity and to publish those calculations to increase transparency. It also calls for open, coordinated, and transparent planning on both local and regional levels.

Wind Variability

We need to have better measurements of wind power plants' output as we integrate wind energy into existing power systems. We also need to develop a way of managing wind power so it can be more readily called upon when needed. Dr. Surya Santoso, wind power research engineer, University of Texas 2007

The major challenge to using wind as a source of power is that the wind is intermittent and variable and does not always blow when electricity is needed. Not all winds can be harnessed to meet the timing of electricity demands. The Department of Energy, the National Renewable Energy Laboratory, universities and utilities are researching the the generation and transmission operational impacts that occur due to wind variability as well as the best practices for wind integration into the grid and the technical requirements of energy storage systems that would serve as temporary "batteries" for harnessing and releasing stored wind energy at optimal times.

Additional Resources:

For a wind power transmission overview, see the ***Wind Energy Overview*** in the Texas Comptroller's 2008 energy report.

Everything's Bigger- and Greener-in Texas *April 2007*
Big industry has big plans for wind energy transmission in Texas.

Putting Wind on the Wires: A Texas Tale *March 2007*
This Utility Wind Integration Group explains how Texas is tackling the problem of integrating more wind energy in to the grid.

Final Report of the Texas RE-Connect Project
This report was provided by Austin Energy under a grant from the U.S. Department of Energy. The report, "*Interconnection and Net Metering of Small Renewable Energy Generators in Texas,*" provides information on how Texas electric utilities handle requests to interconnect and net meter small renewable energy generating systems in the hope that such information-sharing would encourage more consistent approaches statewide.

IREC's Connecting to the Grid Program
The Interstate Renewable Energy Council (IREC) Connecting to the Grid program provides services and resources to facilitate the development of interconnection standards and net metering for renewable-energy systems and other forms of distributed generation (DG). This

page of the IREC web site serves as an information clearinghouse on interconnection and net-metering issues.

Scope of Competition in Electric Markets in Texas
January 2007. The Public Utility Commission of Texas report to the 80th Texas legislature. The report includes discussion of wind transmission, ERCOT and CRUZs.

Need for Transmission and Generation Capacity in Texas: Renewable Energy Implementation and Costs
Public Utility Commission of Texas
December 2006

AWEA Transmission Policy
An American Wind Energy Association (AWEA) web site.

Wind Power & Transmission: Getting the Rules of the Road Right
An AWEA article.

Utility Wind Integration Group
The mission of the Utility Wind Integration Group (UWIG) is to accelerate the appropriate integration of wind power into the electric system through the coordinated efforts and actions of its members, in collaboration with wind industry stakeholders, including federal agencies, trade associations, and industry research organizations.

Fair Transmission Access for Wind
An AWEA publication.

Western Governors Association Transmission Report March 2006

Full text of Senate Bill 20 (SB 20)
Texas Legislative Session: 79(1)

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VALLEY LAKE. Valley Lake, also known as Brushy Creek Reservoir, is on Brushy Creek, a tributary to the Red River, in the Red River Basin three miles north of Savoy in Fannin County (centered at 33°37' N, 96°22' W). The lake extends into Grayson County. The project is owned and operated by the Texas Power and Light Company for the purpose of condenser cooling and other power plant uses for its Valley Creek steam-electric generating station. Construction of Valley Dam was started on April 18, 1960, and completed on September 5, 1961. The lake has a capacity of 16,800 acre-feet and a surface area of 1,180 acres at the service spillway crest elevation of 610 feet above mean sea level. The drainage area is eight square miles, but it is unimportant because the water level in the reservoir is maintained by the diversion of water from the Red River by two pumps installed in the plant at the mouth of Sand Creek.

Seth D. Breeding

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FAIRFIELD LAKE. Fairfield Lake is on Big Brown Creek about eight miles northeast of Fairfield in northeastern Freestone County. In 1967 Texas Power and Light Company, Texas Electric Service Company, and Dallas Power and Light Company announced the construction of a new power plant and an adjacent cooling lake. Industrial Generating Company, a subsidiary of Texas Utilities Company, acted as operating agent for the project. Land acquisition of 5,876 acres and dam construction began in 1968. The contractor, Spencer Construction Company, built a 4,350-foot earthfill dam with a height of 77 feet and top width of 25 feet. Impoundment of the approximately 2,500-acre lake began in December 1969. Tentatively named Big Brown Creek Reservoir, by 1970 the lake was officially named Fairfield Lake. In addition to its industrial use for Big Brown Steam Electric Plant, the lake provides recreational use for area residents and tourists. Fairfield Lake State Park is located on its southern and southwestern shores. As a cooling reservoir for the power plant, Fairfield Lake maintains a much warmer than average temperature, sometimes as warm as 107 degrees in mid-summer. The heated water facilitates redfish, hybrid stripers, and Florida largemouth bass. Swimmers also take advantage of the water's therapeutic benefits.

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FANNIN COUNTY. Fannin County is located in Northeast Texas on the Oklahoma border. Bonham, the county seat, is fifty-five miles northeast of Dallas. The center point of the county is at approximately 33°30' north latitude and 96°10' west longitude. Fannin County comprises 895 square miles of mainly blackland, with a claypan area in the north near the Red River. The topography has little variety, with ranges of moderately rolling hills throughout the county. Fannin County has an elevation ranging between 500 and 700 feet above sea level. The average annual rainfall is a little over forty-three inches. The land is drained by the Red River and Bois D'Arc Creek and is watered by numerous springs. The average minimum temperature in January is 33° F, and the average maximum in July is 94°. The growing season lasts 228 days. The natural flora consists of oak, hickory, ash, walnut, pecan, cottonwood, elm, cedar, and Bois D'Arc trees, as well as redbud, spicewood, dogwood, pawpaw, and dwarf buckeye. The main natural resource is timber; consequently, wood-product manufacture has been important in the local economy.

When European explorers visited the region in 1687 they found it occupied by the Caddo Indians. By 1836, when white settlers first entered the area, no Indians inhabited the land. The Caddoes had joined a larger group known as the Cherokees and their Twelve Associated Bands. White settlers arrived by riverboat at Jonesborough in what is now Red River County. The pioneers crossed the river and established two early colonies. One, named Lexington, was located on the Red River and was headed by Dr. Daniel Rowlett. The other colony, begun by Daniel Slack, was on the east side of the middle Bois D'Arc Creek. Numerous other colonists quickly joined this initial band, and eighty-eight first-class land certificates had been granted before the Texas Declaration of Independence was signed in March 1836.

Because of rapid population growth, Rowlett presented a petition to the Texas Congress on October 5, 1837, requesting that a new county be formed from a section of Red River County west of Bois D'Arc Creek. The county was originally to be named Independence, but during the course of opening debates over the bill the name was changed to Fannin, in honor of James Walker Fannin, Jr., a martyred hero of the Texas

Revolution. The legislation, approved on December 14, 1837, designated the residence of Jacob Black the state house until a more suitable location could be found. The most significant act passed at Black's cabin was to approve the building of the first county road, from Rocky Ford Crossing to Daniel Montague's plantation. The road passed through Fort Warren and bridged Bois D'Arc Creek. Other important legislation dealt with attempts to end Indian hostilities.

On November 28, 1839, another act was passed by Congress to define the boundaries of Fannin County, which at the time included land that later became Grayson, Collin, Cooke, Denton, Montague, Wise, Clay, Jack, Wichita, Archer, Young, Wilbarger, Baylor, Throckmorton, Hardeman, Foard, Knox, Haskell, Stonewall, King, Cottle, and Childress counties, as well as parts of Hunt and Collingsworth counties. The present-day boundaries were established and approved on March 14, 1846.

The development of Fannin County resulted from the efforts of several leaders. These included Bailey Inglish, John P. Simpson, Holland Coffee, Daniel Montague, Daniel Rowlett,[qqv] and Roswell W. Lee. The first successful center of commerce was Warren, a fort founded by Abel Warren in 1836. The first courthouse, school, post office, and Masonic Lodge (Constantine No. 13) in Fannin County were in Warren. The first sermon delivered in Fannin County was preached in Warren by John B. Denton, a Methodist minister. The county government was moved from Black's cabin to Warren on January 8, 1840. The first district court for Fannin County was established at the same time. On April 27, 1840, Judge John M. Hansford opened the first session in the new courthouse.

Bois D'Arc became county seat in turn on January 16, 1843, apparently for two reasons: the Indian threat at Warren, and a shift in political power that strengthened the Bois D'Arc community. Fort Warren no longer wielded significant influence on the development of the county after this move. In 1844 Bois D'Arc was renamed Bonham in honor of James Butler Bonham, a defender of the Alamo. The inhabitants wanted the name to be changed to Bloomington, but the Texas legislature wanted to honor a war hero. Bonham has continued to be the major center of commerce for Fannin County.

The early settlers of Fannin County faced many difficulties with Indians, particularly with the Cherokees and their Twelve Associated Bands. The first skirmish took place on May 16, 1837, when settlers attacked a band of Indians made up of various groups. Tension had been mounting as the Indians grew less friendly with the rapid influx of white settlers and the resulting damage to hunting. The Indians retaliated with constant raids of their own in which settlers were killed and livestock stolen. Stories describe brutal attacks of Indians on cabins and travelers. Residents of Fannin County were infuriated particularly by the Indians' practice of mutilating dead bodies, and their indiscriminate killing of women and children. Skirmishes with the Indians continued over the next six years until the Treaty of Bird's Fort was signed by Edward H. Tarrant with the Tehuacanas, Keechis, Wacos, Caddoes, Anadarcos, and others. This treaty, for the most part, ended Indian hostilities.

Early settlers were predominantly from the South, particularly from

Tennessee. The population of Fannin County grew to 9,217 by 1860; about 19 percent of the residents were black. The county depended upon agricultural products for its main means of support, with livestock, especially beef cattle, being the predominant product. Before the Civil War the county had about 25,000 beef cattle; afterward the number was reduced by half.

The first church in the county was Rehobeth Chapel, built in 1850. Camp meetings had been held since 1840. Other early churches included the First United Methodist Church of Bonham (1844), Vineyard Grove Baptist Church (1847), and First Baptist Church of Bonham (1852). The county has remained overwhelmingly Protestant.

Numerous newspapers were started during the early years of the county. The Bonham *Sentinel*, the first to be published, began in July 1846. The *Northern Standard* was published in Bonham from a month later until April 1847 (*see* CLARKSVILLE *STANDARD*). Other early papers included the *Western Argus* (1847), the Bonham *Advertiser* (1849), the *Western Star* (1853), the Bonham *Independent* (1858), and the Bonham *Era* (1859).

The citizens of the county supported secession, despite a passionate speech for remaining in the Union given by state senator Robert H. Taylor. Fannin County supported the Confederate cause by raising several companies for the trans-Mississippi army. Taylor himself was elected colonel of a cavalry regiment. A Confederate commissary was located in Bonham, from where at least seven brigades drew supplies. A story has it that when a fire destroyed the commissary, which contained a large store of meat, the town turned out en masse to eat the accidental barbecue. More important than the commissary, the county hosted the military headquarters of the Northern Subdistrict of Texas, C.S.A., which was established by Gen. Henry E. McCullough[qv] and located at the site of present-day Willow Wild Cemetery in Bonham. Finally, a Confederate hospital in Bonham housed many of the wounded soldiers during the war.

Fannin County grew steadily from the Civil War to the turn of the century. Agriculture remained the main source of income, with the number of farms increasing throughout the century, and crop production increasing as well. Cotton and corn were the two predominant crops. Numerous new businesses also were started after the war. Previously only five manufacturing establishments operated in the county; by 1870 factories numbered fifty-four, and new ones and continued to come into being. New newspapers included the Bonham *News* (1866), Honey Grove *Independent* (1873), Dodd City *Spectator* (1886), Bonham *Review* (1884), and Honey Grove *Simoon* (1884). The Fannin County Bank was chartered in 1872. The first railroad in the county, the Texas and Pacific, built an east-west track across the center of the county in 1873. Major communities received their first electricity in 1889. The first telephone exchange began in 1889.

Many schools and colleges were chartered during this time period. The county school board, constituted in 1888, helped organize county efforts to school the children. Carlton College was established in 1867 in Bonham by Charles Carlton. Other schools included Ladonia Male and

Female Institute (1860), Paris District Honey Grove High School (1874), Savoy Male and Female College (1876), Lone Pecan School for Boys and Girls (1879), Masonic Female Institute (1881), and Fannin College (1883).

The population of Fannin County peaked in 1900 at 51,793 and slowly decreased afterward, with some fluctuations. Agriculture remained the main source of income. The chief crops were cotton and corn. Cotton production reached its highest level in 1920 with 65,154 bales. Corn production peaked in 1900 with 3,059,430 bushels. In 1900 the county had 7,202 farms, its highest number. Hogs and swine numbered 52,754 in 1900, also a record. Dairy farming had moderate success in the early part of the twentieth century. In 1920, the county fed 14,665 milk cows. The number of businesses in Fannin County peaked in 1900 also. In 1925 the Lone Star Gas company ran a gas main through the county, providing a new source of heat for residents. When aviation became practical, Fannin County residents raised money to build Jones Field near Bonham, in 1929. On December 31 of that year fire destroyed the bell tower of the county courthouse. Fortunately, no records were destroyed.

The Great Depression in the 1930s caused economic hardship that lasted until World War II. In the 1920s and 1930s the population stabilized at around 41,000, but during the 1940s it dropped to 31,253. Businesses hit an all-time low of fifteen in 1947. The number employed in manufacturing dipped to 310 in 1929 and slowly recovered to 630 in 1947. Product value dropped dramatically in 1929 but then slowly increased. Agriculture was hit hard. The depression forced the average farm value to plummet 46 percent below its value in 1920. The number of milk cows dropped sharply in the 1920s, and an effort was made to prime the market in 1929 with financial benefits raised by local businesses. In 1934 the Kraft-Phoenix Cheese Company moved to Bonham and provided a market. By 1940 the number of milk cows had risen to 10,279, but during the 1940s the number began to decrease dramatically. The only livestock to show promise during this time were beef cattle. The number of cattle increased considerably in the 1930s and continued to increase slowly during the rest of the century.

The number of people living in the county dropped dramatically in the 1950s and continued to decline slowly in the 1960s. Fannin County had only 22,705 people in 1970, fewer than its population in the 1880s. During the 1970s the county's population began to rise again, however; there were 24,804 people living there in 1990, and 31,242 in 2000. The educational level of the county gradually increased as well. Seventeen percent of county residents over twenty-five years old had high school diplomas in 1950, and 45 percent in 1980. By 2000 almost 60 percent had graduated from high school, and almost 13 percent had college degrees.

Cotton production took a sharp decline during the 1950s, dropping by half to 24,928 bales in 1959. In 1987 only 337 bales were produced in the county. Corn steadily declined to only 496,557 bushels in 1987. Wheat, the only major agricultural product to increase in the late twentieth century in Fannin County, peaked in 1982 at 1,997,530 bushels. Peanuts and sorghum also increased production in the latter part of the twentieth century.

The number of farms steadily decreased after 1920, to only 1,533 in 1987. Stock farming moved from hogs and milk cattle to beef cattle. Swine production slowly declined in the twentieth century to only a little over a thousand hogs in the 1980s. By 1987, Fannin County had nearly 65,000 beef cattle but only a few thousand producing milk cows. In 2002 the county had 1,976 farms and ranches covering 483,446 acres, 59 percent of which were devoted to crops, 32 percent to pasture, and 8 percent to woodland. That year farmers and ranchers in the area earned $57,364,000; livestock sales accounted for $37,683,000 of the total. Beef cattle, wheat, milo, corn, pecans, and hay were the chief agricultural products.

The number of manufacturing establishments increased from fifteen in 1947 to twenty-nine in 1958 and thirty-seven in 1987. The main commodities were lumber and wood products. Banking and service businesses slowly increased from 1950 to 1990.

The citizens of Fannin County were for many years steadfast Democrats, and during the mid-twentieth century the area benefited from the influence and prestige of Samuel T. (Sam) Rayburn, a resident of Bonham who served as speaker of the U.S. House of Representatives from 1940 to 1961. The voters of Fannin County favored the Democratic candidate in every presidential election until 1972, when Republican Richard Nixon carried the county over Democrat George McGovern. Though Democrats carried the county in 1976, 1980, and 1988, the area's voters had begun to trend Republican. Democrat Bill Clinton was able to win pluralities in the county in 1992 and 1996, partly because third-party candidate Ross Perot ran strong in Fannin County in those elections. (He got about 30 percent of the area's votes in 1992). In the 2000 and 2004 elections, however, Republican George W. Bush won majorities in the county.

Fannin County has remained rural and predominantly white. The racial proportions have been relatively stable, with blacks constituting between 10 and 20 percent of the population over most of the county's history. The black population peaked in 1920 at 5,968 and afterward decreased to 1,633 by 1990. In 2002 Anglos constituted about 85 percent of the people living in the county; blacks accounted for about 8 percent of the population, and Hispanics 5 percent. By 2000 there were 9,900 people living in Bonham, the largest city in Fannin County and its seat of government. Other towns included Honey Grove (1,746), Bailey (213), Dodd City (419), Ivanhoe (110), Ladonia (667), Leonard (1,846), Ravenna (215), Savoy (850), and Telephone (210).

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GRAYSON COUNTY. Grayson County, in north central Texas, is bordered by the Red River and by Fannin, Collin, Denton, and Cooke counties. The county seat, Sherman, which lies approximately sixty-five miles north of Dallas, is part of the Sherman-Denison Metropolitan Statistical Area. The county's center point is at 33°40' north latitude and 96°40' west longitude. Grayson County, 934 square miles in area, has an elevation ranging from 600 to 800 feet and generally level terrain with some low hills. The northern part, which drains into Lake Texoma and the Red River, is characterized by acidic soils of the Post Oak Belt, with loamy or sandy surfaces. The southern areas, which drain to tributaries of the Trinity River, have blackland soils conducive to the growth of trees such as post oak, bois d'arc, elm, and walnut, as well as various types of grasses. Natural resources include limestone, oil and gas, bituminous coal, and sand and gravel. Grayson County is drained principally by Choctaw Creek and its two main tributaries, Post Oak and Iron Ore creeks. The county has an average annual precipitation of thirty-seven inches, temperatures ranging from an average low in January of 30° F to an average high of 96° in July, and a growing season that averages 227 days a year.

Various Caddo groups, including the Kichai, Ionis, and Tonkawa Indians, were the earliest known inhabitants of the area that became Grayson County. These Indians, agriculturalists who found the soils of the area suitable to their way of life, traded and negotiated with the Spanish and French, who moved up the Red River during the eighteenth century to establish trading posts. French and Spanish expeditions resulted in the initial settlements established in 1836-37 at Preston Bend on the Red River, at Pilot Grove in the southeastern part of the county, and at Warren. After the establishment and surveying of the Peters colony in the early 1840s, settlement of the region progressed rapidly. On March 17, 1846, Grayson County, named for Peter W. Grayson, attorney general of the Republic of Texas, was marked off from Fannin County. The legislative action also specified that the county seat be called Sherman. The naming of the county seat in honor of Gen. Sidney Sherman was apparently an effort to effect a compromise between supporters of Sherman, an anti-Houston Whig, and Grayson, a pro-Houston Democrat.

Sherman has the distinction of being one of the few towns in the Lone Star State named by an act of the legislature.

By 1850 Grayson County had a population of 2,008, most of whom had come from Southern states. The census enumerated 186 slaves, used mainly by farmers and stockmen along the Red River and its tributaries to raise grains and livestock, cotton being a minor crop in the area until much later. Throughout the 1850s Preston Bend grew in importance, and the character of the county as a trading and market center gradually emerged. Preston Bend, a landing for passengers and freight in a rapidly developing river trade, was also the northern end of the Preston Road, the state's oldest trail, which extended from the river to south of Austin. Further impetus to county growth occurred with the designation of Sherman as a station on the Butterfield Overland Mail route in 1858. By 1860 Grayson County's population had grown to 8,184, a significant part of the increase having occurred after 1858.

The attitude of the county in 1860-61 toward the issue of secession was not consistent countywide. Although the 1861 election resulted in a vote of 901 to 463 to remain in the Union, Whitesboro in western Grayson County was also the scene of one of the earliest secessionist rallies in Texas. Fear of alleged Union sympathizers in five north central counties, including Grayson, resulted in the deaths of forty men in the Great Hanging at Gainesville in 1862. During the Civil War Grayson County men served the Confederate cause in various parts of the South, but the Eleventh Texas Cavalry, composed of many area recruits, was commissioned to capture the federal forts in Indian Territory north of the Red River. No armed conflict was involved in these captures. The frequent visits of William Clarke Quantrill's guerillas during the war years afforded county residents some anxious moments, but the area suffered neither invasion nor severe deprivation as a result of the war. The political instability and economic depression that characterized much of Texas in the Reconstruction era plagued Grayson County as well. The passing of cattle herds through the crossing at Preston Bend and a steadily developing river trade, however, provided much-needed income to the area.

From 1870 to 1880 settlement in North Texas flourished. The arrival of the Houston and Texas Central Railroad in Sherman and the Missouri, Kansas and Texas in Denison in late 1872 initiated a period of phenomenal growth and development for Grayson County. The population expanded from 14,387 in 1870 to 38,108 in 1880, an increase unparalleled in the entire history of the county. Numerous towns—including Denison, Van Alstyne, Howe, Whitewright, Pottsboro, and Tom Bean—sprang up as a result of the coming of the railroad to Grayson County. The number of farms increased 460 percent between 1870 and 1880, and since the railroads provided transport for produce, Grayson County soon became a milling and market center for surrounding areas. In 1876 Sherman had five flour mills and the largest grain elevator north of Dallas. By 1891 it had erected the largest cottonseed oil mill in the world at that time. Denison, founded by the railroad in 1872, also experienced significant expansion during this period; from 1890 to 1930 its population exceeded that of the county seat. Although manufacturing and milling interests steadily expanded, however, Grayson County remained predominantly agricultural. The number of farms in the county regularly increased, reaching a zenith of 5,762 in 1900. The same year marked the highest production of corn in the history of the county—3,681,640 bushels. Bumper crops of wheat and cotton were also noted, and commercial orchards flourished. Throughout the early years of the twentieth century Grayson County remained agricultural, its farms in 1910 comprising 553,527 of the county's 602,880 total acres.

The advent of the automobile effected significant changes in Grayson County. The first countywide road system, all gravel, was established in 1915, and by 1920 Grayson County had hard-surfaced roads. In 1926 county residents registered 12,314 automobiles, a number that increased to 14,501 in 1930 and 28,427 in 1950. By 1970 the number of registered vehicles had grown to 36,833, and the county had numerous state highways as well as U.S. highways 377, 75, 82, and 69.

Between 1920 and 1930 Grayson County experienced the only decennial population decrease in its history. Having increased steadily from 1850, county population reached 74,165 in 1920. By 1930, however, it had dropped to 65,843, and in spite of subsequent regular increases the 1920 total was not exceeded until the 1970 census enumerated 83,225. The agricultural and manufacturing sectors declined as Grayson County faced the traumas of the Great Depression and World War II.[qqv] The number of farms decreased from 5,169 in 1930 to 4,296 by 1940. Unemployment rose from 6.9 percent in 1930 to 19.5 percent by 1940, and in 1935, 4,705 county residents were on relief. Federal agencies were at work in the county, however, during these years. The courthouse, destroyed by fire in the Sherman riot of 1930, was rebuilt in 1936 with Public Works Administration funds, and the Civilian Conservation Corps did extensive soil-conservation work throughout the area. In 1938 the Rural Electrification Administration brought electric power to rural Grayson County, and by 1944 the cooperative had 2,086 members. The number of members increased steadily thereafter, to 4,633 in 1954, 7,497 in 1964, and 12,197 in 1984.

In 1938 Congress authorized the construction of a dam and reservoir north of Denison to control the flooding of the Red River, generate electrical power, and provide irrigation. Lake Texoma, the reservoir, with a shoreline of 1,250 miles, was developed by the Department of the Interior and the National Park Service and remains a major recreation area and tourist attraction. The dam project was an economic boom to the county, as was the construction of Perrin Air Force Base in 1941. The blow to Grayson County's economy caused by the closing of the base in 1971 was tempered somewhat by the conversion of the facilities into an airport, one of three currently in operation, and an industrial complex. The Denison Dam Project and the construction of Perrin Field precipitated a period of expansion and development that subsequently characterized Grayson County as a whole. Although the sale of livestock and livestock products remained high throughout the 1940s and 1950s, the number of farms decreased at a rate commensurate with declines on state and national levels. The opening of the first oilfield in the county in 1930 heralded a business that became integral to the economy. Grayson County had produced 120 million barrels of oil by 1970 and in 1980 recorded an average annual income of $54,000,000 from oil, gas, and stone, as compared to $28,000,000 from agriculture. In 2000 more than 1,546,800 barrels of petroleum were produced in the county; by the end of that year more than 249,976,800 barrels had been produced in the area since 1930. During the 1970s and 1980s Grayson County emerged as a manufacturing and trade center, with 31 percent of its labor force in 1980 employed in manufacturing and 19 percent in wholesale and retail trade. The 1980 census showed that 60.5 percent of the population twenty-five years and over were high school graduates and 12.9 percent were college graduates. County population totaled 89,796 in 1980 and 95,021 in 1990.

County voting was solidly Democratic before the Civil War and after Reconstruction. The voters of Grayson County favored the Democratic candidate in virtually every presidential election from 1892 through 1976; the only exception occurred in 1928, when Republican Herbert Hoover took the county. In both 1952 and 1956 Dwight D. Eisenhower failed to carry the county, though his birthplace in Denison is the feature of the Eisenhower Birthplace State Historical Site. After 1980, when Republican Ronald Reagan took the county, the area began to trend Republican. Republican presidential candidates carried the area in virtually every presidential election from 1980 through 2004; the only exception was 1992, when independent candidate Ross Perot won a plurality of the county's votes.

In 2000 the census counted 110,595 people living in Grayson County. About 85 percent were Anglo, 6 percent were black, and 6 percent Hispanic. More than 80 percent were high school graduates, and more than 17 percent had college degrees. By the early twenty-first century the area had become a distribution and trade center for north Texas and southern Oklahoma; manufacturing and agriculture were also important elements of the local economy. In 2002 the county had 2,597 farms and ranches covering 441,246 acres, 53 percent of which were devoted to cropland and 40 percent to pasture. In that year farmers and ranchers in the area earned $41,865,000; livestock sales accounted for $21,857,000 of the total. Beef cattle, wheat, nurseries and turf, forage, and horses were the chief agricultural products. In 2000 there were 35,082 people living in Sherman, the county's seat of government. Other towns include Denison (2000 population, 22,773), Bells (1,190), Collinsville (1,235), Dorchester (109), Gordonville (165), Gunter (1,230), Howe (2,478), Knollwood (375), Luella (639), Pottsboro (1,579), Sadler (404), Southmayd (992), Tioga (754), Tom Bean (941), Van Alstyne (2,502), Whitesboro (3,760), and Whitewright (1,740). Austin College in Sherman and Grayson County Junior College midway between Sherman and Denison offer county residents varied educational opportunities. Several organizations, including the Old Settlers Association, pursue historic preservation and promote awareness of the history and development of Grayson County.

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Published by the Texas State Historical Association
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AUSTIN COUNTY. Austin County, in southeastern Texas thirty-five miles west of Houston, is bordered on the north by Washington County, on the east by Waller and Fort Bend counties, on the south by Wharton County, and on the West by Colorado and Fayette counties. Bellville, the county seat and second largest town, is fifty miles west-northwest of Houston. The county's center point is 29°55' north latitude, 96°18' west longitude. State Highway 36 is the major north-south thoroughfare, while State Highway 159, U.S. Highway 90, and Interstate 10 span the county east and west. The county is also served by two major railways: the Union Pacific and the Burlington Northern and Santa Fe.

Austin County covers 656 square miles on the boundary between the Post Oak Savannah and the Coastal Prairie regions of Texas. The terrain varies from rolling hills in the northern, western, and central sections to a nearly level coastal prairie in the south. Elevations range from 460 feet above sea level in the northwest to 120 feet in the southeast. Most of the area lies within the drainage basin of the Brazos River, which forms the eastern border of the county. The margins of the western and southern sections of the county are drained by the San Bernard River, which forms much of the county's western border. The northwestern portion of the county lies in a zone of blackland prairie surfaced by dark clays and grayish-brown sandy and clay loams. The heavily wooded central section of the county is covered by light-colored sandy loams and sands not suited to agriculture, while the southern prairies are surfaced by dark clay loams and lighter colored sandy loams. Stream bottoms consist of very fertile dark reddish brown alluvium. From southwest to northeast across the sandy soils of the county's midsection stretches a five-mile-wide band of oak-hickory forest. North of this timber belt, on the rolling blackland that covers almost half the county's surface, is a "mosaic" zone of interspersed forest and prairie. In the south the coastal prairie exhibits wide expanses of open grassland fringed by stands of oak and elm. Although the timber and grassland were almost equal in extent during the nineteenth century, the woodland has been reduced in the twentieth century by advancing urbanization; yet between one-fourth and one-third of the county remains heavily wooded. In addition to the predominant post oaks, the county's hardwood forests include such species as hickory, live oak, blackjack oak, elm, hackberry, black walnut, sycamore, and mesquite. A number of creeks, the largest of which include Mill, Piney, and Allens, flow southeastward athwart the timber belt to the Brazos; the bottoms of many of these streams are mantled by thick stands of water oak, pecan, and cottonwood. Mill Creek, with its picturesque, broad, wooded valley, was called palmetto by the Spanish, in commemoration of a species of dwarf palm that once grew on its lower course (*see* TEXAS PALM). North of the timber belt the most abundant types of prairie grass include Indian grass, tall bunchgrass, and buffalo grass, while on the coastal prairie the dominant species are marsh and salt grasses, bluestems, and coarse grasses.

Between 11 and 20 percent of the land in the county is regarded as prime farmland. Substantial reserves of petroleum and natural gas are by far the most significant of the county's limited mineral resources. Although the bears, alligators, and buffalo that once roamed the area disappeared in the nineteenth century, the county still has many wild animal species, including white-tailed deer, coyote, skunk, raccoon, and opossum, and such wild birds as the mourning dove and bobwhite quail. In winter migratory ducks and geese feed on grain in the southern reaches of the county. Recreation areas include the 667-acre Stephen F. Austin State Historical Park at San Felipe, which attracts thousands of visitors annually. Temperatures range from an average high of 96° F in July to an average low of 41° in January. Rainfall averages forty-two inches annually. The growing season averages 283 days per year.

The scanty archeological evidence available suggests that human habitation n the area began as early as 7400 B.C. during the Paleo-Indian Period. The county lies in what appears to have been during late prehistory a zone of cultural transition between inland and coastal aboriginal peoples. During the early historic era the principal inhabitants were the Tonkawas, a nomadic, flint-working, hunting and gathering people, living in widely scattered bands, who traveled hundreds of miles in pursuit of buffalo and practiced little if any agriculture. Their numbers were greatly reduced by European diseases over the course of the eighteenth century. They were regarded as friendly by the white settlers who moved in during the early nineteenth century, but their petty thievery was a continual source of annoyance to the newcomers. Similarly, the Bedias and other distant groups migrated periodically through this area begging and stealing. To the south and west of what is now Austin County, on the coastal lowlands and littoral, dwelt the more bellicose Karankawas, much feared by the settlers. The Wacos, a southern Wichita people, also launched raids into the area down the Brazos River from their villages near the site of present Waco.

Early settlers were somewhat shielded from the depredations of fierce plains tribes such as the Comanches and Apaches by the settlements on the Colorado River to the west and the buffering presence of the Tonkawas to the north. As early as 1823 Stephen F. Austin began organizing a militia with which to defend the frontiers of his colony, and the Austin County area contributed many volunteers for the Indian campaigns. Punitive expeditions were mounted against the Tonkawas in 1823, the Karankawas in 1823 and 1824, and the Wacos in 1829. To at least one such campaign in the early 1820s Jared E. Groce, a wealthy planter, contributed thirty of his own armed and mounted slaves. The success of these operations seems to have sharply curtailed Indian depredations in the Austin County vicinity, and by 1836 they had virtually ceased; until after the Texas Revolution, however, inhabitants of more exposed settlements to the west continued to abandon their homes periodically and take refuge at San Felipe. The theft of a few horses from homesteads along Mill Creek in 1839 marked the last Indian raid within the bounds of present Austin County. The Indians drifted westward and northward, and by 1850 the federal census found none residing within the county.

During the seventeenth and eighteenth centuries the territory that is now Austin County was part of a vast arena of imperial competition between the Spanish and French. It is likely that the first European to set foot within the boundaries of the present county was René Robert Cavelier, Sieur de La Salle, who may have traversed the area in the spring of 1686 and crossed the San Bernard near present Orange Hill, while traveling northeastward from his base at Fort St. Louis, above Matagorda Bay, in a desperate attempt to reach the Mississippi River. Some authorities believe that La Salle again crossed the vicinity early in 1687 on his last fatal trek toward the Mississippi. The first Spaniard to reach the area seems to have been Alonzo De León, governor of Coahuila, who may have ventured through in the spring of 1689 while searching for traces of La Salle's expedition. De León returned to the vicinity in the spring of 1690 in the company of the Franciscan priest Damián Massanet on a mission to the Tejas Indians, traveling from Garcitas Creek on Lavaca Bay northeastward to the headwaters of the Neches River. His general route, which followed a crude Indian trace through southeastern Texas and is believed to have passed along the northern border of what is now Austin County, later became known as the La Bahía Road and served as a major thoroughfare between the presidios at Goliad and San Francisco de los Tejas, near the site of present Crockett. In 1718 Texas governor Martín de Alarcón, having founded the Villa de Béxar and San Antonio de Valero Mission, crossed the territory of the future county on an expedition from Matagorda Bay to the missions of East Texas. Pedro de Rivera y Villalón traversed the area on an inspection tour of the presidios of Texas in 1727. Forty years later the Marqués de Rubí also passed through the vicinity on an official inspection of the Spanish frontier. The Atascosito Road, a military road linking Refugio and Goliad with Atascosito, a fortified settlement on the lower Trinity River near the site of present Liberty, was constructed by Spanish authorities during the mid-eighteenth century; a section of the road extended through the southern reaches of the future Austin County.

American settlement in the area began in the early 1820s with the founding of Stephen F. Austin's first colony. By November 1821, just ten months after the Spanish government's acceptance of Moses Austin's colonization application, four families had encamped on the west bank of the lower Brazos. The next month saw the arrival of several additional parties of colonists, and settlement proceeded rapidly. In the fall of 1823 Stephen F. Austin and the Baron de Bastrop chose a spot on the west bank of the Brazos at the Atascosito Crossing, now in southeastern Austin County, to be the site of the unofficial capital of the colony, San Felipe de Austin. The settlement quickly became the political, economic, and social center of the colony. By the end of 1824, thirty-seven of the Old Three Hundred colonists had received grants of land. These early settlers were attracted to the well-timbered, rich, alluvial bottomlands of the Brazos and other major streams; the especially prized tracts combined woodland with prairie. Most of the immigrants came from Southern states, and many brought slaves. By the late 1820s these more prosperous settlers had begun to establish cotton plantations, emulating the example of Jared Groce, who settled with some ninety slaves on the east bank of the Brazos above the site of San Felipe and in 1822 raised what was probably the first cotton crop in Texas. In 1834 more than one-third of the 1,000 inhabitants of the future county were African Americans.

Industry began here in the mid-1820s, when the Cummins family constructed a water-powered saw and grist mill near the mouth of Mill Creek, probably the first mill of its kind in Texas; not long thereafter the first cotton gins were established. Soon San Felipe, the first true urban community to develop within the Austin colony, ranked second in Texas only to San Antonio as a commercial center. By 1830 small herds of cattle were being driven from San Felipe to market at Nacogdoches. Cotton, however, the chief article of commerce, was carried overland by ox-wagon to the coastal entrepôts of Velasco, Indianola, Anahuac, and Harrisburg. Unreliable water levels and turbulence during the spring rains discouraged steamboat traffic on the Brazos as high as San Felipe, and the stream's meanders rendered the water route to the coast far longer than land routes. After 1830, however, steamboats gradually began to appear on the lower Brazos, and by 1836 as many as three steamboats were plying the water between landings in Austin County and the coast. During the 1840s a steamboat line on the Brazos provided regular service between Velasco and Washington.

The area played an important role in the events of the Texas Revolution. The conventions of 1832 and 1833[qqv] were held at San Felipe and, as the site of the Consultation of November 3, 1835, the town became the capital of the provisional government and retained the role until the Convention of 1836 met the following March at Washington-on-the-Brazos. After the fall of the Alamo, Gen. Sam Houston's army retreated through Austin County, pausing briefly at San Felipe before continuing northward up the Brazos to Groce's plantation. On March 30, 1836, the small garrison under Moseley Baker that remained at San Felipe to defend the crossing ordered the town evacuated and then burned to keep it from falling into the hands of the advancing Mexican army. Residents fled eastward during the incident known as the Runaway Scrape. After a brief skirmish with Baker's detachment at San Felipe in early April, Antonio López de Santa Anna marched his army southward for Harrisburg, but not before his troops had looted the eastern part of the county. In May 1836, as news of the Texans' victory at San Jacinto spread, residents began returning to what remained of their homes and possessions.

Although the state of Coahuila and Texas designated San Felipe the capital of its Department of the Brazos in 1834, the first machinery of democratic government in Austin's colony appeared in 1828 with the establishment of the ayuntamiento of San Felipe; the municipality over which it exercised authority extended from the Lavaca to the San Jacinto rivers and from the Old San Antonio Road to the coast. The jurisdiction was progressively narrowed by the formation from it of fifteen additional municipalities; by 1836 the Municipality of San Felipe had acquired boundaries approximating those of modern Austin County, with the addition of a large region in the south that was broken off to form Fort Bend County in 1837, and a wide strip of territory on the east bank of the Brazos, which remained in the county until the end of Reconstruction. The Constitution of the Republic of Texas (1836) made counties of the former Mexican municipalities, and by 1837 Austin County, named in honor of Stephen Austin, had been officially organized. Although the burning of San Felipe left the town unavailable to serve as the capital of the republic, the partially rebuilt town became the county seat of Austin County. After a referendum of December 1846, however, Bellville became the county seat; this new community was near the geographical center of the county. The transfer of administrative functions was completed in January 1848.

In 1831 J. Friedrich Ernst, a native of Lower Saxony, was granted a league of land on the banks of Mill Creek in what is now northwestern Austin County. Ernst described his new home in glowing terms in a letter to a friend in Germany, and his descriptions were reprinted in newspapers and travel journals in his homeland. Within a few years a steady stream of Germans began settling in Austin, Fayette, and Colorado counties. In 1838 Ernst surveyed a townsite on his property on which the community of Industry arose. Between 1838 and 1842 alone, several hundred Germans moved near the town; those not establishing permanent residence soon began rural communities throughout northern and western Austin County. In some instances, as at Industry, Cat Spring, and Rockhouse, the immigrants founded all-German towns; more commonly, however, they formed German enclaves within areas previously settled by Anglo-Americans and often became numerically and culturally dominant.

Most of the early German immigrants were from provinces of northwestern and north central Germany; among them, however, were increasing numbers of Austrians, Swiss, Wends,[qqv] and Prussians. Most soon acquired land and began cultivating cotton and corn like their Anglo-American neighbors, although many followed the example of prosperous early settlers Friedrich Ernst and Robert J. Kleberg[qv] and raised tobacco. The crop was either fashioned into cigars locally to be marketed in San Felipe and Houston—the activity that inspired the name Industry—or, during the 1840s, was sold to the German cigar factory at Columbus in Colorado County. In the 1850s a cigar factory was established at New Ulm in Austin County. By the mid-1840s Austin County's growing reputation as a haven for German settlers began attracting immigrants brought to Texas by the Adelsverein. The failure of revolution in Germany in 1848 triggered a new wave of immigration to Austin County in the late 1840s and 1850s consisting largely of political dissidents, many well educated.

The newcomers were quick to establish not only educational and religious institutions but a wide array of voluntary associations devoted to such pursuits as literature, singing, marksmanship, agriculture, and gymnastics, as well as mutual aid. A striking indication of the Germans' emphasis upon education was the campaign launched in 1844 to establish a university on the German model at Cat Spring. Among the community's cultural achievements was the founding of an influential German-language newspaper, *Das Wochenblatt*, originally published at Bellville by W. A. Trenckmann in 1891; the paper was later moved to Austin. Not until the Civil War did German migration into the county subside. By 1850 the county population included 750 German-born residents, 33 percent of the white population; American-born farmers outnumbered their German-born counterparts by the same two-to-one ratio. By 1860, however, German-born farmers outnumbered the American-born.

Bolstered by the area's generous natural endowments and high rates of immigration from both Germany and the southern United States, Austin County quickly recovered from the destruction of the Texas Revolution. In 1836 the county's population stood at an estimated 1,500. During the ensuing quarter-century of agricultural prosperity the population grew rapidly. The upper South—particularly the states of Tennessee, Kentucky, Virginia, and North Carolina—remained the most important source of settlers in the county until after the Civil War. By 1847 the county's population had risen to 2,687; it climbed to 3,841 by 1850 and to 10,139 by 1860.

The steady stream of southerners arriving with slave property pushed the county's slave population steadily upward. From 447 in 1840 it climbed to 1,093 in 1845 and to 1,274 in 1847; at that time slaves constituted more than 47 percent of the total population. Slaves numbered 1,549 by 1850 and 3,914 (39 percent of the population) by 1860. During the 1840s more than thirty Austin County residents were planters, that is, owners of twenty or more slaves or other considerable property; by 1860, 46 residents held twenty or more slaves. With 324 slaveholders in 1860, Austin County was one of only seventeen counties in the state in which the average number of slaves per owner was greater than ten. In 1860 twelve Austin County residents ranked among the wealthiest individuals in the state, i.e., as holders of at least $100,000 in property. Six residents held more than 100 slaves.

Amid the rising tide of servile labor the smallest and undoubtedly most incongruous of the county's minorities was its free black inhabitants. The census found seven free blacks in the county in 1847 and six in 1850. These may have been members of the Allen family, longtime residents of the area, two of whom, George and Sam Allen, had helped evacuate and burn San Felipe in 1836. By 1860, however, no free blacks remained in the county.

From 1824 to 1837 San Felipe was the only town in Austin County. By the early 1850s, however, Industry, Travis, Cat Spring, Sempronius, Millheim, and New Ulm had appeared. Many communities were simply open clusters of farmsteads with a post office and general store in the center of the settlement. Despite a modest increase in steamboat traffic on the Brazos, the chief mode of commercial transportation continued to be the ox wagon, as a brisk trade developed between Austin County and the burgeoning town of Houston. Finally, in the late 1850s, the first railroad arrived in the area, as the Houston and Texas Central extended its main line northward through Hockley to reach the new town of Hempstead, in the eastern district of the county east of the Brazos, in June 1858. Cotton transported to the rail line by wagon from western Austin County crossed the Brazos at a number of ferries between San Felipe and the mouth of Caney Creek.

Austin County agriculture grew remarkably in antebellum Texas. The county's 381 acres of improved land in 1850 expanded to 58,869 acres by 1860, and the number of farms multiplied from 230 to 790. Cotton and corn continued to be the most significant crops. In 1850 cotton production was 3,205 bales. By 1860 it had grown almost 500 percent, to an astonishing 19,020 bales. Corn production was 149,230 bushels in 1850 and 400,800 bushels in 1860. Irish potatoes increased from 3,530 bushels in 1850 to 9,809 in 1860. In the same period oat cultivation rose from 1,469 bushels to 2,418. Only sweet potatoes and tobacco fell off, the former from 37,322 bushels in 1850 to 32,273 in 1860, and the latter from 9,663 pounds to 5,175 in the same interval. Stock raising retained its early status as a pillar of the local economy throughout the antebellum period, as herds multiplied rapidly on the open range of the lush coastal prairies south of Bernard Creek. In 1850, 20,791 cattle were raised in the county; just ten years later the figure had increased 242 percent to 71,271. Sheep production registered a 250 percent increase, from 2,104 animals in 1850 to 7,407 in 1860. The number of horses raised in the county more than doubled, from 2,386 in 1850 to 5,497 in 1860. In the same period hog production rose from 12,871 animals to 21,177.

The average German farm was barely half the size of that of the average slaveless Anglo-American in the late antebellum period. Most German immigrants arrived in Texas too late to receive free land, the distribution of which ceased in the early 1840s. Furthermore, most had been compelled to expend so much of their money on the way that they had relatively little to buy land and livestock. In 1856 Germans near Cat Spring formed one of the earliest agricultural societies in Texas, the Cat Spring Landwirthschaftlicher Verein, which continues to the present. Germans also owned few slaves. Yet, except in the case of a relatively small group of Forty-Eighter intellectuals, this circumstance was due far less to philosophical opposition to slavery—as many Anglo-Americans suspected—than to the fact that most German immigrants lacked the money to buy slaves. The few Germans who did own slaves were generally those who had immigrated during the 1830s and 1840s and had thus accumulated the requisite wealth. By 1860 only about a dozen of Austin County's German residents were listed as slaveholders in the federal census reports; most owned fewer than five slaves, while the largest German slaveholder, Charles Fordtran, owned twenty-one. Many German farmers raised tobacco, the local production of which they soon dominated, in the belief that the crop required the sort of intensive care that slaves could not provide. German yeomen, moreover, utilized far more hired labor than did their neighbors, drawn from new immigrants, who continued to arrive. German farmhands, who usually preferred to work for Germans, could be hired more cheaply than slaves.

Secession brought turbulence. In early 1859 mounting fear of slave insurrections inspired the formation of the county's first patrol system. As early as February 1860 a mass meeting at Bellville advocated secession if the "aggressions of the North upon the South" continued. Six months later the tension had increased; another public meeting at Bellville called upon the county's ministers to cease preaching to blacks in public places. Unionist sentiment, however, was also in evidence during the crisis. "Frequent, enthusiastic, and well-attended" Unionist meetings in which Germans were prominent were reportedly held in Austin, Washington, Fayette, Lavaca, and Colorado counties throughout 1860. When Austin County elected representatives to the Secession Convention in late 1860, one of the delegates refused to attend the gathering on ground that although a majority of those casting ballots favored a convention, they did not constitute a majority of the county's eligible voters. However, in the referendum of February 23, 1861, Austin County approved secession 825 to 212. Several heavily German precincts had voted decisively against the secession ordinance.

With the coming of the war hundreds of Austin County residents, including many prewar Unionists, enlisted in Confederate or state military units. State formations to which companies organized in the county were attached included the Second, Eighth[qv], Twenty-first, Twenty-fourth, and Twenty-fifth Texas Cavalry regiments, the First and Twentieth Texas Infantry, and Waul's Legion[qv]. However, much of the rush to enroll in state and county militia companies, so-called "home-guard" units, had less to do with motives of patriotism than with the desire to avoid combat. Many German residents had immigrated to the United States to avoid military service in Austria, Prussia, or other European states; many Germans were reluctant to risk their lives in defense of the "peculiar institution" of slavery. The Confederate government's adoption of conscription in early 1862 deepened the difficulty of the many county residents, both foreign-born and native, who were desperately trying to remain neutral in the conflict. Besides rushing to enlist in home-guard units, many draft-age males gained exemption from conscription as wagoners or teamsters. But as the war dragged on and exemptions became more difficult to obtain, men subject to the draft resorted to increasingly drastic measures. Some county residents fled the state for Mexico. Others, who could not abandon their families entirely, hid in the woods. Some of these returned to their homes at night to plow their fields by moonlight. Some county residents serving with Confederate units deserted upon returning to their homes on furlough. The names of forty such men, most of them German, were published in the Bellville *Countryman* in December 1862. By late 1862 county enrolling officers were claiming that 150 Germans subject to conscription had refused to present themselves for induction. Confederate officials were thoroughly aroused by the situation developing in the county. It was reported that forcible opposition to conscription was being organized in the German settlements of Austin and surrounding counties. Gatherings of from 500 to 600 individuals, conducted in German to foil possible Anglophone spies, were said to have been held at Shelby, Millheim, and Industry in December 1862 and early January 1863. Unionist militias complete with cavalry formations had reportedly begun drilling. One Unionist group published a petition to the governor detailing the grievances of the draft resisters. The petitioners claimed that they could not abandon their suffering families just as spring planting was set to begin, inasmuch as the county had made no provision for the relief of the needy; local merchants, moreover, refused to accept the very currency with which Confederate troops were paid.

The crisis came to a head on January 8, 1863, when martial law was declared in Austin, Colorado, and Fayette counties. Several companies of the First Regiment of Gen. H. H. Sibley's Arizona Brigade were rushed from New Mexico to suppress the uprising. A detachment of twenty-five soldiers under Lt. R. H. Stone was sent to Bellville to arrest the ringleaders of the Austin County resistance. The detainees were turned over to local authorities; most of those arrested were German, but some of the principal conspirators were not. By January 21 the rebellion had been officially quelled and all who had been conscripted were coming forward for enrollment. However, the arrests left bitterness. The homes of several German farmers had been ransacked, prisoners had been beaten, and their families had been abused. This deepened the contempt of the Germans for the Confederate enrollment officers. Nor did the events of January end the search for subversives in Austin County. In October 1863 Dr. Richard R. Peebles, a founder of Hempstead and respected local physician, and four coconspirators were arrested on charges of treason for having circulated a pamphlet that urged an end to the war. After brief stints in the jails of San Antonio and Austin Peebles and the other prisoners were exiled to Mexico.

Scores of German county residents loyally served in the Confederate Army. Hempstead, because of its strategic location on the Houston and Texas Central Railway, became an important assembly point for troops from throughout Central Texas. A Confederate military hospital was constructed at Hempstead, and three Confederate military posts were established in the vicinity; one of these, Camp Groce, was one of only three prisoner of war camps in Texas. At least five smaller military camps were scattered through the county west of the Brazos River. When the Union navy tightened its blockade of the Texas coast, local planters shipped cotton to Matamoros in long caravans of ox wagons to be exchanged for salt, flour, cloth, and other commodities. Even so, expanded domestic manufacturing had to be relied upon to fill most needs. Several county businesses produced munitions: a gunsmith shop in Bellville reconditioned rifles and muskets for the Confederate Army; foundries in Bellville and Hempstead produced canteens, skillets, and camp kettles under contract with the state of Texas; the Hempstead Manufacturing Company made woolen blankets, cotton cloth, spinning jennies, looms, and spinning wheels. Nobody starved in Austin County during the war, but suffering was widespread, especially among families with soldiers in the field.

Unfortunately, the end of the fighting in the spring of 1865 did not bring the expected end to strife; Reconstruction in Austin County, as in much of the rest of Texas, was violent and chaotic. The war years had brought another expansion of the county's black population, as planter refugees from the lower South flocked into the area seeking protection for their slave property. Between 1860 and 1864, according to county tax rolls (which probably understate the matter), slave population increased by 47 percent to 4,702. Though some blacks entering the county returned after the war to the communities from which they had recently been uprooted, many others remained. The war had scarcely ended before the federal government moved to garrison Austin County. From August 26 to October 30, 1865, Hempstead was occupied by elements of the Second Wisconsin Cavalry and several other units under the command of Maj.

Gen. George A. Custer. After Custer went to Austin, Hempstead was garrisoned for a time by a small detachment of the Thirty-sixth Colored Infantry. Two white companies of the Seventeenth United States Infantry were posted in Hempstead from 1867 to 1870. The garrison was controlled by the subassistant commissioner of the thirteenth subdistrict of the Freedmen's Bureau, which embraced all of Austin County and had headquarters at Hempstead. Charged with protecting the lives, property, and civil rights of all citizens, including freedmen, the troops helped ensure equal access to polling places and the court system, but their numbers were too few and their resources too limited to permit them to enforce the laws everywhere within the county.

Capt. George Lancaster, head of the local Freedmen's Bureau office in 1867, declared that racial animosities in the area were so intense that only a spark was needed to set off an explosion. Violent confrontations between federal soldiers and local residents were common throughout the Union occupation. The numerous reports in the bureau records of violent crimes committed against blacks by whites portray a campaign of intimidation conducted against the freedmen; with Republicans and Democrats struggling for control of the county's black vote, most if not all of these crimes were politically motivated. The appearance of the Republican-sponsored Union League in the county in early 1867 outraged white Democrats, who responded by forming a Klan-like organization. The violence was most intense in the eastern district of the county, where the black population was concentrated; there the whipping, shooting, and even lynching of blacks became almost routine; few culprits were ever brought to justice. But blacks were not the only targets of white wrath. In March 1867 two soldiers were shot to death for what subassistant commissioner Lancaster termed the "crime" of wearing the federal uniform, "in the eyes of these white desperadoes a sufficient cause for murder." In the spring of 1869 a white Republican newspaper editor from Houston, visiting Hempstead to address a black audience, was accosted by a mob and run out of town. Interracial altercations characterized as riots broke out on at least two occasions in the eastern district near Hempstead in 1868. Yet with federal troops on hand to safeguard freedmen's rights, a number of blacks in Austin County were elected to positions in local government during Reconstruction. In the gubernatorial election of 1869 black voters helped provide victory in the county for Radical Republican Edmund J. Davis. By 1873, however, as previously disfranchised Confederate sympathizers recovered their political rights, the Democrats had regained control of the county's electoral machinery; thoroughly intimidated, few blacks risked casting a ballot. The smashing Democratic victory that resulted signaled the end of Reconstruction and the permanent eclipse of Republican power in the county.

Amid all the turmoil, the county's black residents set about constructing new lives for themselves. By 1870 Austin County's population had climbed almost 40 percent above its level of a decade before, to 15,087. Black population had increased about 68 percent, to 6,574, and now amounted to some 44 percent of the county's population. As blacks began to construct their own free institutions, the first black churches in the county appeared; by 1869 the Freedmen's Bureau had established one of the first black schools in the county's history, in a period when schools of any sort were rare. Plantations in the bottoms of the Brazos and other streams were broken into small farms operated by black sharecroppers. Once the initial restlessness had ended, the diligence of free black labor surprised many white observers. However, some of the county's white residents—including A. Thomas Oliver, who had owned more than 100 slaves—decided not to wait for results from the economic and political experimentation and exiled themselves from the United States in the first years after the war. Oliver and many other of these emigrants settled in Brazil, where they established colonies and raised cotton with slave labor.

Regardless of the freedmen's diligence, as a landless class they soon proved vulnerable to exploitation by white landlords, who often withheld wages from black laborers. However, not all whites were unsympathetic to the blacks' plight. Austin County resident Adalbert Regenbrecht recalled that during Reconstruction he became "probably the first justice of the peace in Texas in whose court a freedman recovered wages for his labor from his former master." Perceiving the exploitation of blacks under the developing crop-lien system, and fearful that immigrants from their homeland would also become trapped in this sort of peonage, German residents of the county wrote to prominent newspapers in Germany in 1866 to warn prospective immigrants not to sign labor or tenant contracts with former slaveowners before arriving in Texas. Driven by such fears, German rates of land ownership in Austin County were not only far higher than those of blacks but higher than those of Anglos as well.

Reconstruction politics was largely responsible for a crucial alteration of the county boundaries. As early as 1853 the residents of the eastern part of the county had begun petitioning the legislature for a separate county east of the Brazos, citing the expense and inconvenience of crossing the river to transact routine business in Bellville. When the petition was revived in 1873, the beleaguered Davis administration, fighting for its existence, decided to grant the request by carving a new county out of eastern Austin and southern Grimes counties. The Republicans expected to dominate the new county, with its large black population, and hoped that by grafting onto it a large section of northwestern Harris County, where hundreds of Democratic voters lived, they could pull Harris County into the Republican column. Waller County, established on May 19, 1873, removed from Austin County not only a fertile agricultural district but also the thriving commercial center of Hempstead, with its cotton mill, iron foundry, and rail facilities. The effects of the loss were mitigated, however, by a postbellum revival of both foreign and domestic immigration. Nevertheless, in 1880 Austin County's population of 14,429 was almost 5 percent below the 1870 figure. Black population, in particular, declined some 67 percent between 1870 and 1880, to 3,939, or 27 percent of the overall population. Renewal of domestic immigration, primarily from Gulf South states—especially Alabama—offset some of the losses. Even more significant was the revival of foreign immigration. Germans continued to settle in Austin County until the end of the nineteenth century, albeit in smaller numbers than during the antebellum period. By the 1980s fully 49 percent of the population was of German ancestry. However, the principal source of postbellum immigration was Czechoslovakia. The first Czechs had settled as early as 1847 in the vicinity of Cat Spring, where they formed what became the first Czech community in Texas. Throughout the 1850s Czechs continued to arrive in small numbers, taking up farming among the German population on the blackland prairie soils of northern and western Austin County and spilling into adjoining counties. After the Civil War the pace of Czech immigration increased; in the decade after 1870 alone more than 800 Czechs settled in Austin County, and smaller numbers continued to move into the area until after the turn of the century. The Czechs, who usually resided in German localities, only slowly established cultural institutions of their own; yet eventually they created a distinctive Czech-Texan identity. By the end of the nineteenth century at least ten communities in the county had appreciable numbers of Czech residents, and Sealy, Wallis, and Bellville had large Czech populations. Austin County had 1,205 foreign-born residents in 1860; by 1870 that figure had increased 150 percent to 3,010, or 20 percent of the population; the number grew by another 25 percent in the following decade, to 3,752—26 percent of the population. Subsequently the proportion of foreign-born residents declined steadily, to 16 percent by 1900, 13 percent by 1910, and 4 percent by 1940. The black population grew between 1880 and 1890 by 32 percent and then increased another 19 percent the following decade, to crest at 30 percent in 1900. Railroad construction in the county in the late nineteenth century provided employment for hundreds of black workers, many of whom took up residence in segregated sections of such rail towns as Sealy, Wallis, and Bellville. After the turn of the century, however, the county's black population began to decline, both absolutely and as a proportion of the population, a trend that continued into the late twentieth century. Disastrous farming conditions after the 1890s drove many farmers, including blacks, off the land in the early years of the twentieth century, just as railroad employment in the county was also disappearing. In the ten years after 1900 the county's black population fell by 23 percent. After remaining virtually unchanged in the succeeding decade, it decreased again by 14 percent during the lean years from 1920 to 1940. From 1940 to 1950 it fell almost 46 percent, to 3,016—or 21 percent of the population—as farm tenancy began to disappear and defense-related industrial jobs opened to blacks in urban areas of Texas and the North and West. Over the next thirty years the decline continued at a rate of more than 5 percent a decade; by 1980 the county's black population stood at 2,580, less than 15 percent of the whole. A bare 1 percent increase in absolute numbers between 1980 and 1990 failed to check the relative slide, so that by 1990 blacks constituted just 13 percent of the county population.

Austin County's economy recovered slowly from the havoc of the Civil War. By 1870 county farms had fallen to scarcely 45 percent of their 1860 value. No county resident in 1870 owned property worth so much as $100,000. By the end of the nineteenth century, however, the revival of cotton farming and stock raising had restored much former prosperity. The number of cattle fell by almost 16,700 between 1860 and 1870, and similar declines were registered in each of the two succeeding decades; by 1890 the county's production had fallen to 33,847 animals, or 47 percent of the 1860 figure. In part the decline was attributable to the loss of the territory east of the Brazos. However, with improvements in breeding and production techniques, each animal became more valuable than ever before. From 1890 to 1900 cattle production rebounded more than 20 percent, to 40,771, and in the latter year the value of the county's livestock herds finally surpassed that of 1860. Although the number of cattle grew only modestly over the next four decades, to 44,477 in 1940, their dollar value increased dramatically. Swine raising, similarly, never regained its antebellum levels in terms of numbers of animals, but remained significant nonetheless. From 1860 to 1890 the county's swine herds declined by more than 30 percent, to 14,492 animals. Over the next ten years, however, the swine count increased almost 29 percent, to a postbellum peak of 18,642. In the four decades after 1900, however, production fell almost 45 percent, to 10,270 in 1940. Sheep ranching actually exceeded antebellum levels as early as 1870, when 7,554 animals were counted. However, the county's flocks declined by more than 60 percent between 1870 and 1880, to a rather insignificant 2,930, and remained almost unchanged until the mid-twentieth century. The county's impressive poultry production and dairy products industry, although mainly devoted to home consumption until after the Civil War, gained substantial commercial importance after the late nineteenth century, when poultry, eggs, and butter began to be shipped by rail to markets in neighboring counties.

As in the antebellum period, cotton culture remained the most important economic activity in the county. Inasmuch as virtually every farmer raised the valuable staple, the postbellum increase in farms and cultivated acreage inevitably meant increased cotton production. The number of farms in the county increased by an average of almost 570 each decade in the forty years after 1860, to a postbellum peak of 3,064 in 1900. In the same time, acres of improved farmland rose 126 percent, to 133,077. Although cotton production fell by 37 percent between 1860 and 1870 (to 11,976 bales), the chaos of the immediate postwar years was soon overcome and output began to climb. In the thirty years after 1870 cotton production expanded 117 percent, to stand at a historic crest of 26,087 bales in 1900; acres planted in cotton peaked the same year at 53,925. With the move to diversify agriculture in the early twentieth century, cotton production declined again in the four decades after 1900, yet it was still a respectable 14,260 bales in 1940. Cotton acreage remained almost unchanged until 1930, but declined sharply thereafter.

Tobacco continued to be an important crop among the county's German farmers until after 1880, when, with the coming of the railroad, tobacco growers became convinced that cotton offered higher profits. The 3,682 pounds of sotweed raised in 1870 had dwindled to only 596 pounds by 1890; small quantities continued to be produced well into the next century, but local cigar manufacturing ended in the late nineteenth century.

Corn culture in postbellum Austin County recovered quickly from the effects of the war; production exceeded peak antebellum levels as early as 1870, when more than 445,000 bushels was raised. By the end of the next decade almost 27,000 acres of farmland was planted in corn. Both output and acreage expanded steadily for the next sixty years, until in 1940 a record 805,600 bushels was produced on a record 40,500 acres. Local farmers, especially Germans, experimented with small grains throughout the nineteenth century. Problems of climate and disease, however, hampered rye and wheat crops in Austin County during the nineteenth century. With the advent of the railroad and expansion of cotton culture, most efforts at producing small grains were abandoned until the mid-twentieth century, although oats continued to be raised on a significant scale at times.

Gardening and the cultivation of orchard fruits for home consumption have been important in the county almost from the beginning. However, the commercial production of fruits and vegetables began only with the improvement of rail facilities in the late nineteenth century. Thereafter, truck gardening, especially for the Houston market, grew rapidly. In 1903 the Bellville Truck Growing Association was formed, and other commodity associations, such as the Cat Spring Pickling Cucumber Association, were soon organized. Watermelons were grown commercially as early as 1903; by 1924, 1,450 train cars of melons were shipped from the county annually, and production continued to expand afterward. Dairying, limited to home consumption throughout the early history of the county, became significant commercially with the advent of improved transportation facilities; by the early twentieth century several creameries were in operation. Viticulture has been little practiced in the county; in the 1880s some members of the Cat Spring Agricultural Society reportedly raised Herbemont grapes, and almost 5,000 pounds of grapes were grown in 1900. Wine making has not been significant commercially; in 1870, for example, only 770 gallons of wine was manufactured, while 5,205 was produced in 1900.

Boosted by the postwar revival of immigration, by the end of the nineteenth century Austin County had overcome the loss of its populous eastern district. After falling almost 5 percent between 1870 and 1880, the county's population grew by an average of almost 22 percent a decade over the next twenty years to reach a peak of 20,676 in 1900. Many of the county's postbellum immigrants, like most of its black population, became tenant farmers, as the rapid spread of cotton cultivation produced a rapid expansion of the crop-lien system and agricultural tenancy. As early as 1880 almost 47 percent of the county's farmers were tenants. That proportion remained virtually unchanged until the mid-twentieth century, when the Great Depression and changes in federal farm policy reduced cotton cultivation and tenancy rates began to decline.

The postbellum economic revival was stimulated by improvements in the county's transportation system. The county received its first rail service in the late 1870s when the Gulf, Colorado and Santa Fe Railway extended its Galveston-Brenham main line through Wallis, Sealy, and Bellville. During the 1880s the GC&SF constructed a branch line from Sealy to Eagle Lake through southwestern Austin County, and by the early years of that decade the Texas Western Narrow Gauge Railway operated a line between Sealy and Houston. In the mid-1890s the Missouri, Kansas and Texas Railroad built its Houston-La Grange spur through Sealy and New Ulm. In 1901 the Cane Belt Railroad constructed a line between Sealy and Eagle Lake, while almost simultaneously the Texas and New Orleans Railroad extended its Houston-Eagle Lake spur through Wallis. The railroads made thriving communities of Sealy, Bellville, Wallis, New Ulm, and Cat Spring, and relegated to insignificance towns deprived of their service, such as San Felipe. With the development of the automobile in the early twentieth century, trucks increasingly assumed the business of transporting produce to market, yet the county's roads remained primitive until after World War I. Although as early as 1912 some communities had issued bonds for road improvement, during the 1920s a Good Roads movement began in earnest and construction began on a network of paved farm roads, a project that continued through World War II. State Highway 36 was extended through the county in 1936 and U.S. Highway 90 was built in 1937. With the completion of Interstate 10 in 1965 the county was equipped with an imminently functional road system.

Transportation improvements stimulated industry as well as agriculture. Industrial activity in the early history of the county had been confined to the processing of agricultural and forest products. Gristmills, sawmills, and cotton gins abounded in the county during the antebellum period. By the 1850s the German settlers of New Ulm had established a brewery and a cigar factory, and at least two cigar factories continued in operation in the county in the 1880s. The county's first iron foundries and cottonseed oil mills were also built before the Civil War. By 1860, during the era of small-scale craft production, Austin County led the state in construction of carriages, carts, and wagons; but this ranking slipped after the war, as craft methods were swamped by the competition of market-oriented production. In the late nineteenth century, however, broom and mattress factories were built at Sealy, where the new rail lines provided access to a national market. Bottling works, pickling plants, canneries, and cider distilleries were also established in the county around the turn of the century. The Santa Fe Railroad constructed a roundhouse and machine shop in Sealy, which remained a division headquarters until 1900, when the facilities were moved to Bellville. In 1870, 105 manufacturing establishments in Austin County employed 217 workers; by 1900, 133 establishments had 272 employees. Yet this modest level of industrial development did not alter the overwhelmingly agricultural character of the county's economy. As agriculture slumped in the early twentieth century, so did the county's industries that relied upon it. By 1940 only six manufacturing plants and thirty-eight industrial workers remained in the county.

As black population declined during the era of the First World War, the county's chronic shortages of agricultural labor became acute. To alleviate the condition, increasing numbers of Mexican migrant workers were brought into the county. Many eventually took up residence, so that Mexicans became the largest foreign immigrant group to settle in Austin County during the twentieth century. In 1900 there were 46 Mexican-born residents; by 1920 the figure had increased to 145, and it rose another 60 percent over the next decade, to 242. Although Mexican immigration was sharply curtailed in the early 1940s, the county's Hispanic population has continued to grow and by 1992 constituted 10.5 percent of the total population.

A reconfiguration of the county's agriculture began in the thirties as cotton acreage began to decline under the combined impact of continuing low commodity prices, diminishing soil fertility, the increasing relative inefficiency of small farms, and New Deal acreage-reduction programs. Acres devoted to cotton cultivation in 1930 (52,793) fell by more than 40 percent by 1940. The decline continued over the next half century, so that by 1982 cotton was grown on only 1,633 acres in Austin County.

Although the yield remained as high as 10,957 bales in 1960, by 1987 that figure had been reduced to only 1,408. Likewise, the production of corn, an important feature of the county's economy throughout its history, contracted after the Second World War, with yields falling from 805,599 bushels in 1940 to 220,498 in 1987 and acres planted in corn plummeting over the same period from 40,462 to 3,024. King Cotton's demise drove hundreds of tenant farmers off the land. In 1930 more than 47 percent of county farmers were tenants, but two decades later the figure was 26 percent; by 1980 fewer than 7 percent of the county's farmers were tenants. Meanwhile, the cultivation of hay, rice, peanuts, and truck crops—principally pecans, peaches, and watermelons—was expanded. A boom in stock raising stimulated a boom in the cultivation of such feed grains as sorghum; after 1930 sorghum culture increased enormously, to reach 279,163 bushels in 1987.

Irrigation, which began on an experimental basis in the county after the turn of the century, became more extensive after World War II; in 1982, 10 percent of the county's cropland was irrigated, with much of the acreage devoted to rice culture. Most of the former cotton land, however, was converted to livestock production, which after World War II became the county's chief industry. Between 1930 and 1987 harvested cropland was reduced 54 percent from 104,199 acres to 47,928. By 1982 more than 60 percent of the county's cropland was devoted to pasturage. The number of cattle raised in the county more than doubled in the three decades after 1940, then declined slightly in the seventies and early eighties to stand at 84,599 in 1987. Dairying, a lucrative pursuit since the late nineteenth century, declined after World War II, and by 1987 only five dairy farms were in operation. Between 1940 and 1982 swine production fell by 80 percent; yet a respectable 2,724 hogs were fed in 1987. Sheep raising continued at modest levels after the Civil War, although a decline reduced production in 1987 to 403 animals. Beginning in the late nineteenth century poultry products were a significant source of agricultural revenue in the county; more than 101,000 chickens were raised in 1987. By 1982 fully 83 percent of Austin County's agricultural revenues came from livestock and livestock products. In that year the county ranked 100th in the state in agricultural income.

Residents of Austin County participated enthusiastically in this century's two world wars and contributed their sons unreservedly to both. During World War I, an Austin County Council of Defense was organized, on November 23, 1917. The council vigorously promoted conservation and directed the rationing of flour, sugar, and other commodities. The county exceeded its subscription quota in the four Liberty Loan and Victory Loan bond sales. An Austin County chapter of the American Red Cross with branches in ten communities and a membership of more than 2,800 was formed on November 13, 1917, and worked to provide medical and social services to military personnel and their families and relief to poor people. Black residents of the county were enrolled in segregated Red Cross chapters in a number of towns, including Bellville and Bleiblerville. As hostility toward Germany mounted, the county's large German population fell under suspicion of disloyalty. The use of the German language was prohibited in public schools and non-English-speaking citizens of all ethnic backgrounds were pressured to use English exclusively in schools, churches, social organizations, and other venues.

More than 860 county residents, including 275 blacks, served in the armed forces; thirty-one servicemen died during the war. Hundreds of Austin County's German-American residents, eager to demonstrate their loyalty to the United States, served in 311 branches of the military. There was virtually no resistance to conscription in the county and only two cases of desertion. The county's response to the call during World War II was at least as enthusiastic. But on the home front, Austin County was less directly affected by this conflict than were many other areas of the state. Undoubtedly the most profound impact of the Second World War upon the county was economic. Even as defense-related jobs in the nearby metropolis of Houston siphoned population from the county, the growth of that city created new markets for Austin County agricultural products and thus laid the foundation for postwar prosperity. Industry was also stimulated by proximity to Houston. The number of factories in the county increased from six in 1940 to thirty-one in 1982, and the number of employees in manufacturing rose from thirty-eight to 1,400. Much of the development occurred after 1970 as a result of the migration of heavy industry out of Houston into neighboring towns. By 1980 the Austin County industries with the largest employment, other than agribusiness, were general and heavy construction and steel.

Petroleum was discovered in Austin County in 1915, but the first significant production began only in 1927 with the opening of the Raccoon Bend oilfield northeast of Bellville. Soon other finds were made near Bellville, New Ulm, and Orange Hill. From the end of World War II until 1980 the county's annual production of crude oil seldom fell below a million barrels and occasionally approached three million. Although output finally declined during the eighties, by 1990 more than half a million barrels of oil and several million cubic feet of natural gas were still being produced in the county annually. Almost 318,767 barrels of oil and 14,600,084 cubic feet of gas-well gas were produced in the county in 2004; by the end of that year 114,769,634 barrels of oil had been taken from county lands since 1915. In 1980, 15 percent of the county's workers were employed in manufacturing, 13 percent in agriculture, 23 percent in trade, and 14 percent in the professions; 15 percent were self-employed, and 33 percent were employed in other counties. The last figure reflected the county's accelerating suburbanization after the 1970s, as increasing numbers of white collar workers moved in from Houston.

Under the impact of agricultural depression in the first years of the twentieth century, the county's population fell more than 14 percent between 1900 and 1910, to 17,699. Although it managed to grow almost 7 percent during the brief agricultural revival in the decade of the First World War, the population declined over the next forty years to 13,777 in 1960. After remaining virtually unchanged in the succeeding decade it climbed 28 percent between 1970 and 1980, before rising another 12 percent in the next decade, to stand at 19,832 in 1990. By the early years of the twentieth century Sealy had surpassed Bellville to become the county's largest town, a position it maintained throughout the rest of the century.

Politically, Austin County has demonstrated a certain independence. Although the Democratic party was dominant from the end of Reconstruction to the late twentieth century, the Republicans managed occasional surprises during that period. In the presidential election of 1880 Republican James Garfield triumphed in the county over former Union general Winfield Scott Hancock, an accomplishment repeated by Republicans James S. Blaine in 1884 and William McKinley in 1896. Although familiar third-party movements such as those of the Greenbackers and Populists made little headway in Austin County—the latter was especially tainted by suspicions of nativism—in 1920 German-American voters threw the county decisively to the little-known American party of James E. Ferguson. After 1952, when Republican Dwight Eisenhower took the county, the area began to trend Republican. With the sole exception of the election of 1964, Austin County voted Republican in presidential elections from 1948 through 2004. Until the late twentieth century, however, the overwhelming majority of voters remained registered Democrats, and few non-Democrats won state or local elections in the county. Exceptions to this generalization include victories by Republican senatorial candidate John Tower in 1966, 1972, and 1978, and Republican gubernatorial candidate William Clements in 1978 and 1986. By the mid-1990s Republican candidates for state and local offices had become much more competitive in county elections.

In 2000 the census counted 25,590 people living in Austin County. About 72 percent were Anglo, 16 percent were Hispanic, and 11 percent were African American. Almost 75 percent of residents age twenty-five and older had four years of high school, and more than 17 percent had college degrees. In the early twenty-first century agribusiness, tourism, and some manufacturing were key elements of the area's economy, and many residents commuted to work in Houston. In 2002 the county had 2,086 farms and ranches covering 367,497 acres, 51 percent of which were devoted to pasture and 37 percent to crops. In that year Austin County farmers and ranchers earned $24,040,000, with livestock sales accounting for $18,366,000 of that total. Beef, hay, cotton, corn, grain sorghum, and pecans were the chief agricultural products. Bellville (2000 population, 3,794) is the seat of government, and Sealy (5,248) is the county's largest town. Other communities include Wallis (1,172), San Felipe (868), New Ulm (640), Industry (304), Kenny (200), Frydek (150), Cat Spring (76), and Bleiblerville (71).

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FORT BEND COUNTY. Fort Bend County (K-21) is in the coastal plains of southeastern Texas. Richmond, the county seat, at 29°35' north latitude and 95°45' west longitude, is twenty-eight miles west-southwest of Houston and at the approximate center of the county. The county comprises 869 square miles of level to slightly rolling terrain with an elevation ranging from eighty to 250 feet above sea level. Temperatures range from an average high of 94° F in July to an average low of 44° in January; rainfall averages slightly more than forty-five inches a year, and the growing season lasts 296 days. The Brazos River flows diagonally northwest to southeast through the county and drains the broad central valley via numerous creeks and bayous. The San Bernard River, which forms the west boundary, drains the western quarter of the county. Major streams include Big Creek, which flows east into the Brazos River; Oyster Creek, which winds parallel to and east of the Brazos River; and Buffalo Bayou, which rises in the northern tip of the county and flows east into Harris County. Soils vary from rich alluvial in the Brazos valley to sandy loams and clay on the prairies. Native trees include pecan, oak, ash, and cottonwood; there are some timberlands in the north and along streams. Mineral resources include natural gas, oil, and sulfur; sand, clay, and gravel are also produced in commercial quantities.

The settlement of Fort Bend County began in the early 1820s as part of the Anglo-American colonization of Texas under the auspices of the Spanish government. Authorization to settle 300 families in the valleys of the Brazos and Colorado rivers was initially granted to Moses Austin, but plans were delayed by his death in June 1821 and Mexican independence from Spain. Stephen F. Austin assumed the responsibility of leadership from his father and gained confirmation of the original Spanish grants from the newly established Mexican government in 1823. Following arrangements with Austin, a group of colonists sailed from New Orleans in November 1821 on the schooner *Lively* and anchored near the mouth of the Brazos River on the Texas coast. In 1822 a small party of men from this group left the ship and traveled inland some ninety miles and, on a bluff near a deep bend in the river, built a two-room cabin. As the settlement grew, the cabin became known as both Fort Settlement and Fort Bend; the latter name, in time, prevailed. In 1824 the Mexican government issued documents officially granting to the colonists their leagues of land. Of the 297 grants, fifty-three were issued to Fort Bend settlers (*see* OLD THREE HUNDRED). The presence of the Karankawa Indians near the new colonial settlements proved to be a comparatively minor problem. The first settlers had a few skirmishes, but as the colonies increased, the Karankawas began moving out of the area and by the 1850s had migrated as far south as Mexico.

In May 1837 the Congress of the Republic of Texas passed an act incorporating nineteen towns, including Richmond. Robert Eden Handy of Pennsylvania and William Lusk of Richmond, Virginia, both of whom had arrived in Texas shortly before the war for independence from Mexico, founded and named the town with eight other proprietors, including Branch T. Archer, Thomas Freeman McKinney, and Samuel May Williams.[qqv] An act establishing Fort Bend County and fixing its boundaries was passed on December 29, 1837; Wyly Martin was appointed the first chief justice. On January 13, 1838, the citizens voted to make Richmond the county seat. The county was taken from portions of Austin, Brazoria, and Harris counties. Its irregular shape was, in part, the result of using waterways to form the west and segments of the south and east boundaries. Several efforts have been made to change the lines but with little success.

Some of the first settlers in Fort Bend County played prominent roles in early Texas history. Nathaniel F. Williams and Matthew R. Williams cultivated and milled sugar on their Oakland Plantation near Oyster Creek in the early 1840s, thus laying the groundwork for an industry that continued to develop and thrive in Sugar Land (*see* IMPERIAL SUGAR COMPANY); in 1837 Jane Long[qv] opened a boarding house in Richmond, where she lived until her death in 1880; and Mirabeau B. Lamar moved to Richmond in 1851 and built a plantation home on land purchased from Jane Long. Both Mrs. Long and Lamar are buried in Morton Cemetery, Richmond. During the Texas Revolution many of the people of Fort Bend fled in great haste as Antonio López de Santa Anna's army marched through the area. Part of this army camped at Thompson's Ferry on the Brazos River while part marched on to meet defeat at the battle of San Jacinto. Fort Bend settlers returned from the Runaway Scrape to find their homes plundered or burned and their livestock scattered or dead.

Soon after its founding, Richmond developed into a prosperous trade center for the surrounding agricultural region of the lower Brazos valley. Barges and steamboats plied the Brazos River, transporting cotton and other products to the port at Galveston, as merchants of Richmond and other river towns vied with Houston for the lucrative agricultural trade. Transportation facilities were greatly improved in 1853, when the Buffalo Bayou, Brazos and Colorado Railway was completed to Stafford's Point from Harrisburg, which was located on Buffalo Bayou's navigable channel to Galveston. The prosperity of the 1840s and 1850s, however, ended with the Civil War.

In antebellum Texas slaves were essential to the development of the valley plantations. As early as 1840 there were already 572 slaves in Fort Bend County, and by 1845 that number had risen to 1,172, placing Fort

Bend near the top of counties with the largest slave populations. In 1850, Fort Bend was one of only six counties in the state with a black majority. The labor provided by the burgeoning slave population made possible the growth of the plantation economy. In 1860 there were 159 farms in Fort Bend county, with about 12,000 acres in cotton, 7,000 acres in corn, and 1,000 acres in sugarcane; the slave population totaled 4,127, more than twice that of the 2,016 whites. Fort Bend planters, believing that their economic and social successes, among other reasons, justified the institution of slavery, strongly supported the Confederacy, and, in 1861, voted 486 to O for secession from the United states. The majority of county men volunteered for Confederate service; many joined the Eighth Texas Cavalry (Terry's Texas Rangers), a regiment organized by Benjamin Franklin Terry, a wealthy sugar planter from Sugar Land.

Although battle never reached Fort Bend, the war's duration and ultimate loss imposed economic hardships and social and political stress on the community. During Reconstruction, efforts to live in peace with politics dominated by Radical Republicans and black officeholders brought no more than an uneasy compromise. White Democrats, outnumbered by blacks more than two to one, were unable to regain control of local government until the late 1880s, when their all-out campaign to attract black as well as white votes led to the Jaybird-Woodpecker War. This brief but violent conflict, which took place on August 16, 1889, abruptly ended the Republican, or "Woodpecker" rule, and the Democrats quickly formed the Jaybird Democratic Association. With a constitution that declared as its purpose the "protection of the white race" and "an honest and economical government," the association controlled local politics mainly through the white primary, which excluded blacks until the United States Supreme Court, in 1953, supported a lower court's ruling forbidding the practice. The Jaybird Association accepted the ruling, continued for a few years, then disbanded in 1959.

Fort Bend County remained a state Democratic party stronghold until the 1970s, when the combination of population growth and the growing association of conservative political ideas with the Republican party broke the trend. In a special election held in April 1976 the people of the county elected Ron Paul, a physician from Lake Jackson in Brazoria County, as congressman, the first Republican elected to office in Fort Bend County since Reconstruction. Paul focused his campaign on the evils of "big government" and the "ultraliberalism" of his Democratic opponent.

New towns and a new demography began to develop in the last quarter of the nineteenth century as railroads branched out across the county. In 1878 the Gulf, Colorado and Santa Fe line from Galveston crossed the Galveston, Harrisburg and San Antonio (the former Buffalo Bayou, Brazos and Colorado) one mile west of Richmond. This junction, called Rosenberg, became a community when the developers of the New York, Texas, and Mexican Railway made it their headquarters in 1882. With the addition of the San Antonio and Aransas pass and the Texas and New Orleans railroads, all parts of the county were served. The new lines, with routes passing through potentially productive farmlands, attracted new settlers, many of whom were immigrants from Central Europe. Germans, Austrians, and Bohemians (*see* CZECHS) comprised 400 of the 5,259 new residents entering the county from 1890 to 1900. They were primarily agrarian in orientation—small farmers or merchants serving farmers—and many were Catholic. Their distinctly different cultural and linguistic characteristics added a new dimension to the established Anglo-Protestant community, and their agricultural achievements contributed to the county's economic stability and development. Among the many towns founded in the 1890s by or for these immigrants were Beasley, Needville, and Orchard, which still exist as small rural communities serving farmers.

Missouri City, on the far eastern edge of the county near Houston, was founded in 1894; Katy, a tri-county town in Fort Bend, Waller, and Harris counties, developed after the Missouri, Kansas and Texas (Katy) Railroad was completed to that point. In the 1890s, a million-dollar refinery was built at Sugar Land and a new cane mill was constructed; in 1907, they were purchased by the Imperial Sugar Company, a major industry in the county and the only cane-sugar refinery in Texas.

In 1920 Rosenberg's population edged past Richmond's by the thin margin of 1,273 to 1,279; by 1950 Rosenberg residents overshadowed those of Richmond 6,210 to 2,030. Two decades later, Rosenberg-Richmond, as the "twin cities" population center, had counts of 12,098 and 5,777, respectively, in a county of 52,134 residents. Fort Bend County population declined between 1940 and 1950; however, in the same period, Rosenberg grew by nearly a third and Richmond held steady, a fact that reflects the national rural-to-urban movement.

Fort Bend County produces substantial minerals. Throughout the county subterranean salt domes hold concentrated deposits of oil, gas, sulfur, and salt that made early development possible. Gulf Oil Company brought in the first commercially producing oil well in 1919 at Blue Ridge and, three years later, located another major field at Big Creek. Thompsons had a major oilfield in 1921. In 1926 Gulf discovered a major sulfur and gas deposit in Orchard; the Humble Oil Company (now ExxonMobil Corporation) opened a high-producing gas field near Katy in 1935 and later built a gas plant that produced 450 million cubic feet of gas daily in the mid-1980s. Between 1954 and 1957 oil production in the county averaged 30,000 barrels a day, as compared to the 21,600 barrels a day in 1963. As demand for petroleum increased in the mid-1970s, developers managed to bring in forty new wells in 1976 and 1977, providing the county with $121 million from the sale of crude oil. Since that time a recession in the petroleum industry has caused development in the county to drop sharply. In 1976 the top three taxpayers in the county were, in order, Exxon, Gulf, and Houston Lighting and Power Company; in 1983 the top three taxpayers were Houston Lighting and Power, Exxon, and Utility Fuels. Gulf dropped to fourth place.

Farming and ranching have been the central focus of Fort Bend County economic and social life since its inception. The influx of new settlers in the 1880s and 1890s helped county agriculture to change from antebellum plantations to productive small farms. The county had 2,365 farms with 183 acres each in 1900, in contrast to 995 farms with 154 acres each in 1890. The national recession of the 1890s, a major flood on the Brazos River in June 1899, and the great Galveston hurricane of 1900 forced many farmers into tenantry. By 1910, 61 percent of the county's farmers were working as cash or share tenants. By 1925, of the 3,659 farms in the county, approximately 72 percent were operated by tenants, a partial result of a statewide economic recession and adverse summer weather from 1919 to 1922. During the World War II years, with the rural to urban movement and military service, farm tenantry dropped, and full ownership of farms increased. Since the 1960s, home developments, industry, business, and commerce in the county have forced a trend toward fewer commercial farms. The 1974 Census of Agriculture reported 1,340 farms in the county, but only 758 of these reported cash sales in excess of $2,500. Among the four top agricultural commodities for cash income in the mid-1980s were cotton, sorghum, beef cattle, and rice. Cotton culture, a source of income for nearly 700 families in the county, varies greatly with seasonal weather, allocated acreage, and selling prices. Sorghum culture has increased in recent years due to favorable selling prices and more consistent profit. Total value of the crop in the county in 1976 was $11 million. Rice culture began as early as 1901 with plantings on acreage once considered worthy only of grazing; rice yielded eighteen to twenty bags an acre in 1903. The 1990 annual acreage was just above 25,000 acres, with a yield of 4,488 pounds per acre. In 1982 agriculture provided more than $90 million in average annual income for the county.

Ample grazing land and free-roaming herds of longhorn cattle encouraged the first settlers in Fort Bend County to combine cattle raising with farming. The Fort Bend County Book of Brands indicates that landowners with minimal acreage tried to turn a profit in the cattle business. As elsewhere in Texas, the boom years of the 1870s and early 1880s culminated in the bottom falling out of the market by 1886. Local cattlemen began fencing their pastures and upgrading their herds with shorthorns, Brahmans, and Herefords. Today, more farms in the county produce cattle than any other cash crop.

Transportation facilities for Fort Bend County include the Southern Pacific and the Santa Fe railroad systems, two commercial lines of motor-freight services, and two airports for private and commercial aircraft. Major highways are U.S. Highway 59, which joins U.S. Highway 90 Alternate in the county and runs northeast to southwest; Interstate 10, an east-west route through Katy; State Highway 6, north-south through Sugar Land; and State Highway 36, north-south through Rosenberg. Numerous farm roads serve the rural areas.

Until the last decade commerce and industry have been associated with the development and transport of oil, gas, and sulfur in the county. Local businesses provided agricultural needs and products and services for the communities. As the population increased in east Fort Bend County, a result of Houston's westward expansion, industry and commerce became more diverse. Among the top ten commercial taxpayers in Fort Bend County in 1983 were three property-development corporations and two high-technology corporations.

In the last decades of the twentieth century Fort Bend was among the fastest-growing counties in the United States. Between 1980 and 1990 the population nearly doubled, from 130,960 to 225,421. In 1990, 62.6

percent of the population was white, 20.7 percent black, 19.5 percent Hispanic, 6.4 percent Asian, and 0.2 percent American Indian. The largest communities were Rosenberg (20,183), Houston (with 27,027 in Fort Bend County), Missouri City (32,219 in Fort Bend County), and Sugar Land (24,529). Two major social and cultural events characteristic of the county and its people are the Fort Bend County Fair, first held in 1933 and still held annually each October, and the Fort Bend County Czech Fest, first held in 1976 as a spring tourist attraction and continued annually each May.

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FREESTONE COUNTY. Freestone County is located in east central Texas in the center of a group of counties once known as the Trinity Star. It is bounded on the east by Anderson County, on the south by Leon County, on the west by Limestone County, and on the north by Navarro and Henderson counties. The county's center lies at 31°43' north latitude and 96°07' west longitude; Fairfield, the county seat, is about eighty miles southeast of Dallas. Freestone County covers 888 square miles of coastal plain upland with an elevation ranging from 600 to 900 feet above sea level. The topography is generally a smooth, even plain with a gentle slope from northwest to southeast. The area is timbered with mesquite on the west, while the eastern half has almost every variety of oak, hickory, and walnut; there is a also scattering of pine groves on the western bank of the Trinity River, which provides drainage for the entire county, with the exception of a small area in the southwest, where runoff finds its way to the Navasota River. Most of the soil is fine sandy loam; springs are common in the deep sandy areas. Rainfall averages about thirty-eight inches per year, and temperatures range from an average high of 94° F in July to an average low of 36° in January. The growing season extends for 263 days. Interstate Highway 45 and State Highway 75 run north-south through the county, while U.S. Route 84 runs northwest to southeast.

Archeological evidence indicates that the area that is now Freestone County was inhabited from the late Holocene era to the arrival of the Spanish. In the historic period the area was inhabited by Caddoan Indians; in the 1830s these included the Kichais, who had a small settlement near what is now Butler, and the Tawakonis, who lived around Tehuacana Creek. Many other tribes also appear to have used the area for hunting and trading. While both the French and Spanish were familiar with the area, the French seem to have had more influence with these Indians, which limited the Spanish presence in the region. In the mid-1820s the Mexican government opened Texas to American colonization through the national colonization law of 1824 and through a law passed by the state of Coahuila and Texas in 1825, which opened uninhabited tracts to contractors and empresarios (*see* MEXICAN COLONIZATION LAWS). One of the first to secure a grant was David G. Burnet, whose land lay in the area that later became Freestone County. Under the terms of his grant, Burnet was authorized to settle 300 families in the area within six years. Little progress was made in executing the provisions of the contract, however, until after 1830, when Burnet joined with other empresarios to form the Galveston Bay and Texas Land Company. In 1833 at least seven Mexican citizens received eleven-league grants, and another twenty-four titles to land were granted between 1834 and 1835. It is unclear how many of these landholders actually took up residence in the area; according to one account, in 1835 the only white inhabitant was James Hall, a fur trader. After the establishment of the Republic of Texas in 1836, the land company's rights to land in the area were terminated, and all lands not previously assigned became part of the public domain. During the early years of the republic period the area that is now Freestone County was considered Indian land and therefore dangerous; very few whites ventured into it until the Indian Treaty of 1843 (*see* INDIAN RELATIONS). So many settlers moved into the region in the years immediately following the treaty, however, that by 1846 every county now bordering Freestone County had been organized. One of these, Limestone County, included the land that would later comprise Freestone County. By the 1840s the white population of the northeastern half of Limestone County had grown significantly. By 1846 a fairly large settlement, later called Troy, had been established along the west side of the Trinity River near Pine Bluff, and in 1848 a few isolated settlers appeared in the southern and central sections of what is now Freestone County. Sometime around 1847 the steamboat *Roliance* made its way up the Trinity River. Others soon followed, bringing supplies for the many settlers moving into the area. Often the heads of families arrived on prospecting missions, then returned home to bring their families back with them. Since the population of Limestone County was rapidly expanding, in 1850 the Texas legislature divided it to form Freestone County. By 1851 the county had been organized; the town of Mound Prairie, in the center of the county, was chosen to be the county seat, and its name was changed to Fairfield. Some other early towns were Cotton Gin, Avant Prairie, Butler, and Bonner Community. By 1860 the agricultural economy was rapidly developing toward the model provided by slaveholding areas to the east; of the county's total population of 6,881, more than half (3,613) were slaves. The United States agricultural census found 417 farms, encompassing 282,803 acres, in Freestone County that year. More than half of these farms were smaller than 100 acres in size (and only two were larger than 1,000 acres), but already a few extensive plantations had been established. Two local landholders owned more than 100 slaves each, and four owned 70 to 100 slaves; all told, there were fifty-seven slaveholders in the county who owned twenty slaves or more. Though corn was the county's most important crop at this time, cotton production was also becoming well established. Over 6,900 bales of cotton were ginned in 1860, and local farmers also produced 5,200 pounds of tobacco, along with other crops such as wheat, oats, and sweet potatoes. Ranching was also an important part of the economy; the agricultural census listed almost 19,300 cattle and 7,700 sheep in 1860. By the early 1860s the residents had also begun to found cultural institutions. A combination school and Masonic lodge was built in Fairfield in 1853, and at least two colleges were established before or during the Civil War, including Fairfield Female Academy[qv], (chartered in 1860) and Woodland College for Boys (established in 1863). Thirteen churches, mostly Methodist and Baptist, had also been established by 1860.

At the Secession Convention of 1861 Freestone County, represented by John Gregg and W. M. Peck,[qqv] voted to secede. After the convention county residents voted 585 to 3 in favor of secession. Preparations for military action were undertaken with 529 men available for duty. The Freestone contingent served well in the war, although there were many casualties. The loss of slave labor and the lack of a good transportation system slowed the economy in the years just after the Civil War, and in 1870 the area's production of corn (about 197,400 bushels) and cotton (6,465 bales) was lower than it had been in 1860. Nevertheless, the county experienced a good deal of growth during this period. By 1870 the agricultural census counted 1,029 farms in the area, more than double the number ten years earlier, and the population had increased to 8,139. The lack of good transportation persisted into the early twentieth century. In the early 1870s, for example, local farmers lost valuable opportunities to link directly to national markets when two railroads, the Houston and Texas Central and the International-Great Northern, skirted the county to the west and south. The local economy profited by the proximity of these railways, however, and the county grew significantly between 1870 and 1900. The number of farms nearly doubled (to 2,111) between 1870 and 1880, then increased to 2,728 by 1890 and to 3,518 by 1900; the number of "improved" acres of farmland more than tripled during this period, rising from 47,558 in 1870 to more than 159,000 by 1900. The population mirrored this growth, reaching 14,921 by 1880, 15,987 by 1890, and 18,910 by 1900.

Much of the county's growth during the late nineteenth century can be attributed to a significant rise in cotton production. About 31,300 acres were devoted to raising cotton in 1880 and about 49,300 acres in 1890; by 1900 that number had risen to almost 72,700 acres. Other aspects of the agricultural economy also developed during this time. By 1900 more than 48,000 acres were devoted to corn production. Sheep ranching declined significantly during this period (by 1900 there were only 346 sheep counted), but cattle ranching continued to flourish, and by 1900 almost 22,700 cattle were counted. Poultry had also become significant in the local economy; by the turn of the century farmers owned almost 112,000 chickens, which produced about 387,000 dozens of eggs that year. Agricultural activity was further encouraged in 1906, when the Trinity and Brazos Valley Railway was built across the county and partially solved the transportation problem, and the economy continued to grow during the first two decades of the twentieth century despite a boll weevil infestation that plagued farmers beginning in 1903. The number of farms increased to 3,518 by 1910 and to 3,587 by 1920. At the same time farm acreage rose from about 324,000 to almost 564,500 acres. By 1920 almost 100,000 acres were devoted to cotton, and more than 50,600 acres were planted in cereal crops, primarily corn. At that time the U.S. census found 23,264 people living in Freestone County.

Agriculture declined dramatically during the early 1920s, however. The county lost 777 farms between 1920 and 1925, when only 2,910 farms remained. One of the most lucrative enterprises during the 1920s, when prohibition was in effect, was bootlegging, centered around the community of Young (or Young's Mill). Illegal whiskey known as Freestone County Bourbon Deluxe was transported out of the county by car, boat, truck, and plane and helped offset the downturn in the economy; according to one source, a number of local families "became wealthy, directly or indirectly," from the liquor trade. More farms were established in the late 1920s—by 1929 there were 3,559 farms in the area —but the rate of farm tenancy among local farmers also rose significantly during this period, from 46 percent in 1920 to 65 percent in 1930. The economy never fully recovered. By 1929 the land devoted to cotton production had dropped to about 93,400 acres, and by 1930 the population had declined to 22,589.

The economic slump continued during the Great Depression of the 1930s. Partly due to newly imposed federal crop restrictions, cropland harvested in the county dropped from 135,700 acres in 1929 to 112,700 in 1940; land in cotton declined by more than 50 percent during the depression years, with only about 44,000 acres left by 1940. Hundreds of farmers left, and by 1940 the county had only 2,761 farms and 21,138 residents. Due partly to farm consolidations, the population continued to decline, to 15,696 by 1950, to 12,525 by 1960, and to 11,116 by 1970. It rose significantly in the 1970s and 1980s, however, as new businesses moved in. While farming and the livestock business remained important, the biggest gains were in the mining industry, which by 1988 employed over 500 workers in the county, up from 20 in 1970. A new electric generating plant just outside of Fairfield caused the public utilities to more than double their work force from 1980 to 1986. Service and retail industries also grew significantly, and the population increased from 14,830 in 1980 to 20,946 by 1990.

Oil was first discovered in the county in 1916, and petroleum and natural gas production contributed to the area's economy into the twenty-first century. Almost 294,000 barrels of oil and 263,851,056 cubic feet of gas-well gas were produced in the county in 2004; by the end of that year 44,889,337 barrels of oil had been taken from county lands since production began.

Democratic presidential candidates carried the county in every election from 1872 through 1968. In 1972, however, Republican Richard Nixon carried the area. Though Democrats carried almost every election in the county from 1976 to 1992, when Bill Clinton won a plurality of the area's votes, Nixon's win in 1972 and Ronald Reagan's in 1984 marked moves away from the area's traditional leanings. By the late twentieth century the Republicans were clearly in ascendance. Republican Bob Dole won a plurality of the county's votes in 1996 and George W. Bush won the county with solid majorities in 2000 and 2004.

In 2000 the census counted 17,867 people living in Freestone County. About 72 percent were Anglo, about 19 percent were black, and 8 percent were Hispanic. About 66 percent of the residents age twenty-five and older had completed four years of high school; more than 9 percent had college degrees. In the early twenty-first century natural gas, mining, quarries, various manufacturing concerns, and agribusiness were the key elements of the local economy. More than 263,851,000 cubic feet of gas-well gas were produced in the county in 2004. In 2002 the county had

1,468 farms and ranches covering 429,339 acres, 53 percent of which were devoted to pasture, 30 percent to crops, and 16 percent to woodlands. In that year farmers and ranchers in the area earned $32,473,000; livestock sales accounted for $30,473,000 of the total. Beef cattle, hay, fruits, vegetables, melons, pecans, and corn were the chief agricultural products. Communities in Freestone County include Fairfield (2000 population, 4,068), the largest town and county seat; Teague (4,557); Kirvin (122); Streetman (203, partly in Navarro County);Wortham (1,082); and Donie (206). Lake Fairfield, in the north central part of the county, provides recreation for residents and visitors, and many historic sites are preserved throughout the county. Blues artist Blind Lemon Jefferson was born in Coutchman and buried in Wortham.

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ANDERSON COUNTY. Anderson County is located in East Texas between the Trinity and the Neches rivers. Palestine, the county's largest town and its county seat, is 108 miles southeast of Dallas and 153 miles north of Houston. U.S. highways 287, 79, and 84 provide the major transportation routes through the county. The county's center lies at 95°36' west longitude and 31°47' north latitude. Anderson County has a total area of 1,077 square miles or 689,280 acres. The county is partly in the Texas Claypan area and partly in the East Texas Timberlands of the Southern Coastal Plains. Almost half of the soil is Fuquay-Kirvin-Darco, deep, sandy, and loamy. The terrain is nearly level to moderately steep in the uplands. The 66,000 acres in the western Claypan area are used mainly for pasture. The Timberlands are used mostly for pasture and woodland. Many varieties of timber grow abundantly, including red oak, post oak, white oak, pecan, walnut, hickory, elm, ash, and pine (*see* LUMBER INDUSTRY). The soil also supports a wide variety of fruits, vegetables, and nuts.

The terrain is hilly and slopes to the Trinity and Neches rivers, with an elevation of between 198 and 624 feet above sea level. The entire eastern area of the county is bordered by the Neches and is drained by Hurricane Creek, Lone Creek, and Brushy Creek. The western area is bordered by the Trinity River and is drained by Massey Lake, Mansion Creek, and Keechie Creek. Mineral resources include oil and gas and iron ore. Temperatures range from an average minimum of 37° F in January to an average maximum of 94° in July. Rainfall averages about 40.5 inches annually, and the growing season averages 264 days.

The territory that became Anderson County was home to the Comanche, Waco, Tawakonis, Kickapoo, and Kichai Indians. These and others, originally on the southern flanks of the Wichita peoples, were in the vanguard of the southern migration. By 1772 they had settled on the Brazos at Waco and on the Trinity upstream from the site of present Palestine.

In 1826 empresario David G. Burnet received a grant from the Mexican government for colonization of the area that is now Anderson County. In

1833 members of the Pilgrim Predestinarian Regular Baptist Church settled at the site of Parker's Fort in Limestone County, and others settled near the site of present Elkhart, where they established "Old Pilgrim," reputedly the oldest Protestant church in Texas. On June 10, 1835, Willison Ewing and Joseph Jordan bought a tract of land, which is now the John H. Reagan homesite, about two miles southeast of the present city of Palestine, and erected Fort Sam Houston as protection from the Indians. In 1836 a settlement known as Fort Houston grew at this site. During the incursion of Antonio López de Santa Anna in the spring of 1836 most of the settlements west of the Trinity were destroyed. Settlers fled to Fort Houston, but many of them returned to Parker's Fort after Santa Anna's defeat. On May 19, 1836, Parker's Fort was attacked by Indians, and most of the families there were killed. Those who survived made their way to Fort Houston. Some residents of Anderson County are related to Cynthia Ann Parker, who was captured in this raid. In October 1838, while Gen. Thomas J. Rusk marched with two hundred men on his way to Fort Houston in pursuit of Mexicans and Indians, he learned that hostile Indians were at a site called Kickapoo, near Frankston, in what is now northeastern Anderson County. His successful raid ended the engagements with the Indians in eastern Texas for that year.

After the removal of the Indians in the 1840s, settlement proceeded rapidly until the area had sufficient inhabitants to form a new county. In response to a petition presented by settlers at and around Fort Houston, the First Legislature of the state of Texas formed Anderson County from Houston County on March 24, 1846. A suggestion was made that the new county be called Burnet in honor of David G. Burnet. The county was named Anderson, however, after Kenneth Lewis Anderson, a prominent member of Congress and the last vice president of the Republic of Texas. Fort Houston was two miles from the center of the county, so a committee, composed of Dan Lumpkin, William Turner Sadler, and John Parker was appointed to lay out the site for and name a new county seat. They chose a 100-acre tract in the center of the county. The Parkers had come from Palestine, Crawford County, Illinois, and upon their suggestion, the new county seat was named Palestine.

On July 30, 1846, the first session of the Anderson County court was called. Road building was of foremost importance, and a road from Palestine to the Neches River was ordered. Other roads from Palestine to Fort Houston, Parker's Bluff, Cannon's Ferry, and Kingsboro in Henderson County followed. Authorization for construction of a courtroom and jail with an underground dungeon was given. In August 1846 a county tax was levied, and Thomas Hanks was appointed county treasurer. In October election precincts were arranged. District court was held on November 9, 1846, with Judge William B. Ochiltree, of the sixth judicial district of Texas, presiding. The first cases were civil cases involving title to land and slaves.

In 1851 the Palestine Masonic Institute was established, with both male and female departments. In 1856 it became Franklin College. When the male department failed, the Palestine Female College was formed and stayed in operation until 1881, when a vote was taken to establish public schools. A school established in 1852 at Mound Prairie was one of the most famous in antebellum Texas.

Most of the settlers in the county came from the southern states and from Missouri. In 1850 the county population was 2,884, of which 600 were slaves, but by 1860 the population had increased to 10,398, of which 3,668 were slaves. During the same time, cotton production had grown from 784 bales to 7,517 bales. Anderson County showed steady growth in population and agricultural production during the antebellum period.

When the Civil War broke out, Anderson County almost unanimously supported secession and sent her ablest men to fight. Judge John H. Reagan served in the cabinet of the Confederate government as postmaster general. Even after the defeat of the South, Anderson County resisted federal rule. During Reconstruction, one loyalist called District Judge Reuben A. Reeves, a resident of Palestine, "the greatest curse of the latter part of the nineteenth-century so far as this District is concerned" because of his refusal to allow blacks to participate as jurors in the judicial process. When the Democratic party gained control statewide, the voters of Anderson County favored the Democratic candidate in virtually every presidential election through 1948; the only exceptions occurred in 1924 and 1928, when Republicans Calvin Coolidge and Herbert Hoover took the county. After 1952, when Republican Dwight D. Eisenhower won a majority of the county's votes, the area's sympathies began to shift, and Republican candidates carried the county in every virtually every presidential election from 1952 through 2004. The only exceptions occurred in 1964, 1968, and 1976, when Democrats Lyndon B. Johnson, Hubert Humphrey, and Jimmy Carter, respectively, took the county.

By 1870 the population of Anderson County had declined to 9,229, 52 percent white and 48 percent black. In 1875, under the leadership of Judge Reagan, the citizens of Palestine and the county joined in voting a bond issue of $150,000 to be given as a bonus to the International-Great Northern Railroad for locating its machine and repair shops and general offices in Palestine. The company employed over 300 men. As a direct result, by 1880, Palestine doubled in size to more than 4,000 people, and the county population nearly doubled in size to 17,395. The county was traversed north to south by the railroad, which branched at Palestine, one set of tracks running to Houston and Galveston and the other to Laredo. The I-GN, currently the Missouri Pacific, still serves Palestine. Palestine is also a hub for the Texas State Railroad. The county population grew steadily upward to 37,092 in 1940, and the white majority increased to 68 percent. Between 1940 and 1970, however, the county declined in population by 25 percent, from 31,875 to 27,162. The white majority increased to 75 percent of the total. Between 1970 and 1980 the population increased to 38,381; whites numbered 29,399, or 77 percent.

Between 1880 and 1940 Anderson County was predominantly agricultural. Corn, cotton, sweet potatoes, hay, and, by the 1920s, peanuts were the most important crops. The timber industry gained importance in the 1930s. Between 1940 and 1982 the number of farms dropped by 70 percent, from 4,422 to 1,356. Crops that remained important in the 1980s included peanuts, sweet potatoes, hay, and fruits and nuts.

In 1881 traces of oil were found. The first rotary rig was shipped to the county in 1902. Good showings of oil caused more local citizens to drill, but no commercial wells were made at that time. In 1916 the Texas Company proved the existence of the Keechi Salt Dome, and in 1926 the Boggy Creek Dome was discovered. In January 1928 the first successful oil producer in Anderson County, known as the Humble-Lizzie Smith No. 1, was brought in. The discovery brought prosperity, and this may account for the county's voting Republican in the 1924 and 1928 elections. The oil discoveries also meant that the Great Depression had a less severe impact than elsewhere.

Manufacture of diverse products, including glass containers, garments, automotive parts, metal and wood products, aluminum, and furniture played an important role in the economy of the county. Manufacturing-related and retail employment rose from 2,006 in 1965 to 3,663 in 1980, accounting for over 55 percent of total employment. Oil and natural gas discoveries, valuable timber regions, rich ranchlands for grazing cattle, iron ore deposits, and the conversion to peanut production kept the price of farm and ranch land steadily increasing. Three units of the Texas Department of Corrections (*see* PRISON SYSTEM) were located at Tennessee Colony in the southwestern part of the county. Education levels advanced. In 1950 only 24 percent of those aged twenty-five or older had at least a high school education. By 1980, however, 51 percent met this standard. In the early 1980s cattle were grazed on 200,000 acres of open land and about 127,000 acres of forest land; commercial timber grew on 200,000 acres; cultivated land comprised 86,000 acres, of which 23,000 was in row crops and the rest was either fallow or in close grown crops or hay. Urban development covered 28,000 acres. Anderson County then ranked twenty-second in production of commercial timber among the forty-three counties in the East Texas pine-hardwood region known as the Piney Woods.

Anderson County experienced growth in oil and gas production during the 1970s and 1980s, and they continued to be significant components of the local economy into the 1990s. Almost 931,300 barrels of oil, and 8,203,929 cubic feet of gas-well gas, were produced in the county in 2000; by the end of that year 295,904,540 barrels of oil had been taken from county lands since 1929. Other sectors, including ransportation, retail and wholesale trade, finance, and the service industries, also grew. Meanwhile the area's population steadily increased, rising from 27,789 in 1970 to 38,381 in 1980 and 48,024 in 1990.

The census counted 55,109 people living in Anderson County in 2000. About 63 percent were Anglo, 24 percent black, and 12 percent Hispanic. More than 64 percent of residents over twenty-five had a high school education, and more than 11 percent had a college degree. In the early twenty-first century agriculture continued to be a significant component of the area's economy, but manufacturing and distribution businesses and tourism also contributed. In 2002 the county had 1,735 farms and ranches covering 365,182 acres, 37 percent of which were devoted to crops, 35 percent to pasture, and 24 percent to woodlands. In that year farmers and ranchers in the area earned $23,063,000; livestock sales accounted for $16,457,000 of the total. Cattle, hay, truck vegetables, melons, pecans, and peaches were the chief agricultural products. Palestine (2000 population, 17,598) is the county's largest town and seat of government; other communities include Cayuga (200), Elkhart (1,215), Frankston

(1,209), Montalba (110), Neches (175) and Tennessee Colony (300). The county attracts numerous visitors, who go there to enjoy the beautiful Dogwood Trails in the spring, balloon launchings at the United States government's Scientific Balloon Base, picturesque train rides to Rusk on the Texas State Railroad, the Engeling Wildlife Management Area, the 900 acre Palestine Community Forest, and other historic sites and museums. Educational opportunities increased with the opening in 1980 of Trinity Valley Community College in neighboring Henderson County.

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Georgia Kemp Caraway

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REGION C

Texas Senate Bill 1
Regional Water Planning
for Region C (North Texas)

Documents

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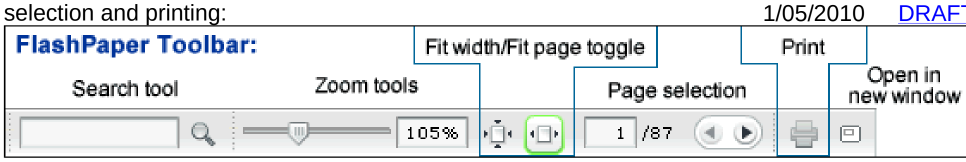

Document categories: Water Plan

Available "Water Plan" Documents

Date Uploaded	File Description
10/01/2001	Cover Page and Table of Contents (42 KB)
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10/01/2001	Section 1 Introduction (5.67 MB)
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10/01/2001	Section 2 (100 KB)
10/01/2001	Section 3 (186 KB)
10/01/2001	Section 4 (57 KB)
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10 Most Recently Uploaded Documents

Date Uploaded	File Description	Category
1/12/2010	Agenda for January 21, 2010 Meeting of the Study Commission on Region C Water Supply	Agenda
1/12/2010	Presentation from January 11, 2010 Region C Water Planning Group Meeting	Presentations
1/05/2010	DRAFT Chapter 1 - Description of the Region	Draft Documents
1/05/2010	DRAFT Chapter 3 - ...ly Available ...s	Draft Documents
	... Chapter 6 - Water ...vation and Drought ...ement Recommendations	Draft Documents
1/05/2010	Memo regarding Potential Legislative Recommendations (Task 8)	Draft Documents
1/05/2010	Official Minutes from November 11, 2009 Region C Water Planning Group Meeting	Meeting Minutes
1/04/2010	Agenda for January 11, 2010 Region C Water Planning Group Meeting	Agenda
1/04/2010	Expanded Agenda for January 11, 2010 Region C Water Planning Group Meeting	Agenda
1/04/2010	Draft Resolution related to the formation of nominating committee to appoint 2010 Region C Officers	Draft Documents

6. Regulatory, Administrative, Legislative, and Other Recommendations

The Texas Water Development Board (TWDB) regional water planning guidelines [1] require that a regional water plan include recommendations for regulatory, administrative, and legislative changes that will facilitate water resource development and management:

> "357.7 (a) Regional water plan development shall include the following…
> (9) regulatory, administrative, or legislative recommendations that the regional water planning group believes are needed and desirable to: facilitate the orderly development, management, and conservation of water resources and preparation for and response to drought conditions in order that sufficient water will be available at a reasonable cost to ensure public health, safety, and welfare; further economic development; and protect the agricultural and natural resources of the state and regional water planning area. The regional water planning group may develop information as to the potential impact once proposed changes in law are enacted."

The guidelines also call for regional water planning groups to make recommendations on the designation of ecologically unique river and stream sites and unique sites for reservoir construction. This section presents the regulatory, administrative, legislative, and other recommendations of the Region C Water Planning Group and the reasons for the recommendations. The recommendations are presented in the following order:

- Summary of recommendations
- Recommendations related to the Senate Bill One planning process
- Recommendations related to TNRCC policy and water rights
- Recommendations for state and federal programs to address water supply issues
- Recommendations for ecologically unique river and stream segments
- Recommendations for unique sites for reservoir development

6.1 Summary of Recommendations

The Region C Water Planning Group makes the following recommendations:

- Recommendations related to the Senate Bill One planning process
  - Allow alternative strategies to be designated for near and long term planning needs.

- Encourage TWDB to exercise discretion in the consideration and approval of funding for alternatives not presented as part of the regional water plan.
- Encourage TNRCC to exercise discretion in the consideration and approval of water right permit applications not part of the regional water plan.
- Allow regional water planning groups to assume that contracts for water supply will be renewed when they expire.
- Provide clarification of the impacts of designating a unique stream segment.

- Recommendations related to TNRCC policy and water rights
  - Make certain water rights exempt from cancellation for ten years of non-use.
  - Reduce the regulatory and legislative obstacles to indirect reuse of treated wastewater.
  - Remove barriers to interbasin transfers of water.
- Recommendations for state and federal programs to address water supply issues
  - Increase funding for Texas Water Development Board loans and the state participation program to assist with the development of water supply projects.
  - Accelerate studies of groundwater availability for the Trinity aquifer in North Texas.
  - Increase state participation in water conservation efforts.
  - Provide a program for education of board members of Water Supply Corporations, Special Utility Districts, and Municipal Utility Districts.
  - Increase state participation in watershed protection planning.
  - Encourage federal funding for development, maintenance, and upgrading of NRCS structures.
  - Provide state assistance with maintenance and construction of stock ponds.
  - Encourage Texas Department of Agriculture to include water supply questions on its survey of farmers and ranchers.
- Recommendations for ecologically unique river and stream segments
  - Provide clarification of the impacts of designating a unique stream segment.
- Recommendations for unique sites for reservoir construction
  - Marvin Nichols I
  - Lower Bois d’Arc Creek
  - Muenster

- o Tehuacana

These recommendations are discussed in greater detail below.

6.2 Recommendations Related to the Senate Bill One Planning Process

Alternative Strategies for Near and Long Term Needs

Section 357.7(a)(8) of the TWDB Regional Water Planning guidelines requires "specific recommendations of water management strategies to meet near term needs…". As we understand the TWDB interpretation of this requirement:

- Needs through 2030 are near-term needs.
- Listing of a number of alternative strategies among which a water supplier can choose is not allowed for near-term needs.

This requirement decreases the local control and flexibility that have been an important part of the successful efforts to meet water needs in Region C and throughout Texas. Water suppliers need to have a full range of options as they seek to provide new water supplies for Texas' future. It is impossible to foresee all the possibilities for new water supplies in a planning process such as this, and changing circumstances can change the preferred alternative for new supplies very quickly. New laws, court decisions, regulatory changes, permitting decisions, changes in growth patterns, and other factors may make a recommended strategy impossible and require a supplier to develop other alternatives. Limiting the options of water suppliers will make negotiations to obtain needed land or water more difficult and drive up the cost of new water supplies. The following steps should be taken to address these concerns:

- Willing buyer/willing seller transactions of water rights and treated water should not be controlled by this regulation. Such transactions may be beneficial to all concerned and may simply not have been foreseen in the planning process.
- The TWDB and the Texas Natural Resource Conservation Commission (TNRCC) should interpret existing legislation to give the maximum possible flexibility to water suppliers as they seek to serve the public and provide new supplies. Changes in the timing of supply development, the order in which strategies are implemented, the amount of supply from a management strategy, or the details of a project should <u>not</u> be interpreted as making that project inconsistent with the regional plan.

- The TWDB and TNRCC should make liberal use of their ability to waive consistency requirements if local water suppliers elect strategies that differ from those in the regional plan.
- Legislative and regulatory changes should be made to allow plans to present alternative sources of supply where appropriate.

Requirement that a Project Must Be Consistent with the Regional Water Plan to Receive Funding from TWDB

The Senate Bill One legislation requires that a project must be consistent with an approved regional plan in order to receive funding from TWDB. The TWDB has changed its rules to reflect this legislative mandate.

This requirement raises many of the concerns cited above in the discussion of alternative strategies for near and long term needs:

- It decreases local control and flexibility.
- It deprives water suppliers of options.
- It deprives TWDB in flexibility in funding desirable and needed projects.
- Plans must change over time because it is impossible to foresee changing circumstances.
- Limiting the options of water suppliers will make negotiations to obtain needed land or water supplies more difficult and drive up the price of water.

The following steps should be taken to address these concerns:

- Willing buyer/willing seller transactions of water rights and treated water should not be controlled by this regulation. Such transactions may be beneficial to all concerned and may simply not have been foreseen in the planning process.
- The TWDB should interpret existing legislation to give the maximum possible flexibility to water suppliers as they seek to serve the public and provide new supplies. Changes in the timing of supply development, the order in which strategies are implemented, the amount of supply from a management strategy, or the details of a project should <u>not</u> be interpreted as making that project inconsistent with the regional plan.
- The TWDB should make liberal use of its ability to waive consistency requirements where local water suppliers elect strategies that differ from those in the regional plan.
- Legislative and regulatory changes should be made to allow the TWDB to exercise discretion in the consideration and approval of funding for alternatives not presented as part of the regional water plan.

Requirement that a Project Must Be Consistent with the Regional Water Plan to Receive a Water Right Permit from TNRCC

The Senate Bill One legislation requires that a project must be consistent with an approved regional plan in order to receive a water right permit from TNRCC. The TNRCC has adopted rules to reflect this legislative mandate. Section 297.41(a)(3)(E) of TNRCC regulations indicates that "(a) Except as otherwise provided by this chapter, the commission shall grant an application for a water right only if…(3) the proposed application…(E) addresses a water supply need in a way that is consistent with the state water plan and an approved regional water plan for any area in which the proposed appropriation is located, unless the commission determines that new, changed, or unaccounted for conditions warrant waiver of this requirement…." Section 297.41(b) further indicates that the commission shall not issue a municipal water right after September 1, 2001, in any region that does not have an approved regional water plan unless the commission waives the requirement.

This requirement raises many of the same concerns cited in the two discussions above:

- It decreases local control and flexibility
- It deprives water suppliers of options.
- It limits TNRCC's ability to permit the best alternative to meet water supply needs.
- Plans must change over time because it is impossible to foresee changing circumstances.
- Limiting the options of water suppliers will make negotiations to obtain needed land or water supplies more difficult and drive up the price of water.

The following steps should be taken to address these concerns:

- Willing buyer/willing seller transactions of water rights and treated water should not be controlled by this regulation. Such transactions may be beneficial to all concerned and may simply not have been foreseen in the planning process.
- The TNRCC should interpret existing legislation and regulations to give the maximum possible flexibility to water suppliers as they seek to serve the public and provide new supplies. Changes in the timing of supply development, the order in which strategies are implemented, the amount of supply from a

management strategy, or the details of a project should not be interpreted as making that project inconsistent with the regional plan.

- The TNRCC should make liberal use of its ability to waive consistency requirements where local water suppliers elect strategies that differ from those in the regional plan.
- Legislative and regulatory changes should be made to allow TNRCC to exercise discretion in the consideration and approval of water right permit applications not part of the regional water plan.

TWDB Regulations Regarding the Treatment of Contract Expiration in Senate Bill One Planning

TWDB has interpreted its current regulations to require regional water planning groups to assume that water will not be made available from one entity to another after the expiration of current contracts. A water management strategy to renew the contract is required to make the water available after the expiration of the current agreement. If the buyer and seller of the water currently plan to renew their commitment (which they usually do), this requirement forces Senate Bill One planning to be unrealistic and to depart from other planning conducted by water providers. The future supplies available to purchasers of water are underestimated, and the future commitments of those providing the water are also underestimated.

The TWDB should change its regulations to allow regional water planning groups to assume that current contracts will be extended beyond the current expiration date if that reflects the current intention of both parties to the contract.

Clarification of Impacts of Designating a Stream Segment as a Unique Stream Segment

As part of the Senate Bill One planning process, regional water planning groups are asked to make recommendations for designation of unique stream segments. It is difficult to make such recommendations because of the uncertain implications of designation of unique stream segments. The legislature should clarify the intent and impact of the unique stream segment designation. Specific questions that should be answered include the following:

- What is the objective of designating a unique stream segment?
- How would adjacent private properties be affected by the designation?

- How will future water rights be affected? For example, would instream flow requirements be imposed on future water rights upstream?
- How will designation affect regulatory programs to protect water quality?
- What types of activities would be restricted as a result of the designation?
  - Reservoirs on the segment
  - Reservoirs upstream from the segment
  - Wastewater treatment plant discharge permits
  - Power lines
  - Municipal separate storm sewer system permits
  - Pipelines
  - Roads
  - Bridges across the segment
  - Landfills
  - Septic systems
  - Other activities
- What area is affected by the designation? The stream? The entire watershed? An area surrounding the stream?
- Can the designation be reversed?

6.3 Recommendations Related to TNRCC Policy and Water Rights

Cancellation of Water Rights for Non-Use

The Texas Water Code currently allows TNRCC to cancel any water right, in whole or in part, for ten consecutive years of non-use. This rule inhibits long-term water supply planning and is particularly undesirable in the case of major reservoirs constructed for municipal water supply. In order to take full advantage of the yield available at a given site, reservoirs are often constructed to meet needs far into the future. In many cases, only part of the supply is used in the first ten years, with the remainder allocated to meeting future growth.

This should be addressed by changing the water code to exempt certain projects from cancellation for ten years of non-use. The exemption might extend to:

- Municipal water rights

- Water rights for steam electric power generation
- Water rights associated with major reservoirs
- Water rights included as long-term supplies in an approved regional water plan.

Policies Limiting Indirect Reuse of Treated Wastewater

The TNRCC has recently implemented policies, some in response to legislative requirements in Senate Bill One, that limit TNRCC's ability to permit projects for indirect reuse, in which water is returned to a reservoir or watercourse before being rediverted for reuse. The policy of discouraging indirect reuse has a number of negative impacts on water suppliers in Region C and throughout the state:

- The policies are logically inconsistent with policies encouraging direct reuse of treated wastewater.
- The policies inhibit reuse for municipal purposes by prohibiting the most effective approach to municipal reuse, which incorporates "multiple barriers" between wastewater discharge and eventual reuse. Streams and reservoirs are among the most effective of such multiple barriers.
- The policies encourage reuse for irrigation and industrial purposes, where direct reuse is appropriate, while discouraging reuse to meet municipal needs, where indirect reuse is a preferred approach.
- It is poor public policy to discourage indirect reuse, which is a water supply alternative with relatively low environmental impacts.
- It is poor public policy to require the construction of infrastructure for direct reuse in cases when natural watercourses can deliver water much more economically.
- Indirect reuse of treated wastewater is an important element of water supply planning in Region C. In many cases, it provides new water supplies with significantly less environmental impact than would alternative sources, such as new reservoirs.

The legislature should revisit the issue of indirect reuse of treated wastewater using the bed and banks of state watercourses, with a view to reducing the obstacles to indirect reuse. In particular, reuse of water that originates from interbasin transfers should be regarded as developed water and regulated under Section 11.042 of the water code, which currently applies only to reuse of water that originated as groundwater. The historical discharge of treated wastewater effluent should not make the indirect reuse of wastewater more difficult.

Requirements for Interbasin Transfers Introduced in Senate Bill One

Senate Bill One introduced a number of new requirements for applications for water right permits to allow interbasin transfers. The requirements are in Section 11.085 of the water code, and they include many provisions not required for any other type of water right. Requirements imposed on interbasin transfers and not on any other water right include the following:

- Analysis of the impact of the transfers on user rates by class of ratepayer
- Public meetings in the basin of origin and the receiving basin
- Extra notice to county judges, mayors, and groundwater districts in the basin of origin
- Extra notice to legislators in the basin of origin and the receiving basin
- TNRCC request for comments from each county judge in the basin of origin
- Proposed mitigation to the basin of origin
- Demonstration that the applicant has prepared plans that will result in the "highest practicable water conservation and efficiency achievable…"

Exceptions to these extra requirements placed on interbasin transfers were made for emergency transfers, small transfers (less than 3,000 acre-feet under one water right), transfers to an adjoining coastal basin, transfers to a county partially in the basin of origin, and transfers to a municipality whose retail service area is partially within the basin of origin.

The effect of these changes is to make obtaining a permit for interbasin transfer significantly more difficult than it was under prior law and thus to discourage the use of interbasin transfers for water supply. This is undesirable for several reasons:

- Current supplies greatly exceed projected demands in some basins, and the supplies already developed in those basins can only be used by interbasin transfers.
- Interbasin transfers have been used extensively in Texas and are an important part of the state's current water supply. For example, current permits allow interbasin transfers of over 600,000 acre-feet per year from the Red, Sulphur, Sabine, and Neches Basins to meet needs in the Trinity Basin in Region C. This represents almost 1/3 of the region's reliable water supply.
- Emerging Senate Bill One water supply plans for major metropolitan areas in Texas (Dallas-Fort Worth, Houston, and San Antonio) rely on interbasin transfers

as a key component of their plans. It is difficult to envision developing a water supply plan for these areas without significant new interbasin transfers.

- Texas water law has always regarded surface water as belonging to the people of the state, to be used for the benefit of the state as a whole. It is important that the law on interbasin transfers reflect this basic approach.
- The current requirements for permitting interbasin transfers provide an unnecessary barrier to development of the best, most economical, and most environmentally acceptable water supplies.
- Since no interbasin transfer permits have been granted under these new requirements, the meaning of some of the provisions and the way in which they will be applied by TNRCC are undefined.

The legislature should revisit the current law on interbasin transfers and remove some of the unnecessary and counterproductive barriers to such transfers that now exist.

6.4 Recommendations for State and Federal Programs to Address Water Supply Issues

Increased State Funding for Texas Water Development Board Loans and the State Participation Program

The Senate Bill One regional water planning studies are showing significant needs for new water supply projects to allow Texas to grow and prosper. The loan and state participation programs of the Texas Water Development Board have been important tools in the development of existing supplies. These programs need to be continued and extended with additional funding to assist with the development of the next generation of projects as the state seeks to implement the Senate Bill One regional plans.

Studies of Groundwater Availability

The TWDB is currently conducting a series of studies of groundwater availability for major aquifers in Texas. Studies of the Trinity aquifer in North-Central Texas, a major source of water for Region C, are currently scheduled for 2004. For several Region C counties, the current use from the Trinity aquifer is much greater than the available reliable supply from the aquifer, as previously estimated by the TWDB. This would indicate that alternative sources of supply should be developed quickly in those counties. However, in at least some of the counties with substantial overdrafts from the aquifer, water suppliers are not encountering significant water supply problems and are reluctant to invest in alternative supplies. It is important that updated water availability estimates be developed as soon as possible to help determine whether development of expensive alternative sources of supply is justified.

TWDB should continue its program of developing new groundwater availability models for major aquifers in Texas. If possible, TWDB should accelerate development of the model and of new availability estimates for the Trinity aquifer in North Texas.

Increased State Participation in Water Conservation Efforts

The current TWDB-approved projections of water demand assume significant reductions in per capita municipal use and industrial and irrigation use due to water conservation measures. In Region C, the projected reductions in per capita use result in a 15 percent reduction in projected municipal water use as of 2050. A major portion of that reduction is projected to come from the requirements for low-flow plumbing fixtures in current state and federal law. However, there are other factors tending to increase per capita use in Region C and elsewhere (smaller household size, development of new housing with large lots in many cities, increasing prosperity). It is important that programs be developed to help local water suppliers achieve the conservation savings included in the current water demand projections.

The legislature should provide funding to allow TWDB and other state agencies to undertake or expand the following programs:

- A study of the effectiveness of municipal water conservation programs in Texas and how state agencies can assist local suppliers in achieving conservation goals.
  - What are the trends in per capita use in the state, in various regions, and for various suppliers, after adjusting for climate?
  - Where has conservation been particularly effective?
  - What are the elements of effective programs, and how might they be applied elsewhere in the state?
  - What other factors besides conservation programs affect per capita municipal use (positively or negatively)?
  - Are conservation-oriented water rates effective? If so, how might they be implemented?

  - How can state agencies most effectively assist water suppliers in implementing conservation programs?

- Similar studies of the effectiveness of conservation in industrial and irrigation water use and how state agencies can assist in achieving conservation goals.
- State funding for educational programs on water conservation in the schools (such as the Major Rivers program and others).
- State funding for seminars on water conservation and conservation issues to educate policy makers, including elected officials, community leaders, board members of water supply entities, and water utility managers.

Development of a Program to Educate Board Members of Water Supply Entities

The state should develop a program for the education of board members of Water Supply Corporations, Special Utility Districts, and Municipal Utility Districts on water supply issues. The program could include seminars on various issues offered across the state, perhaps in conjunction with the Texas Rural Water Association and other groups. It may be appropriate to consider requirements for accreditation of board members to ensure that they understand water supply issues so that they can govern appropriately.

Increased State Participation in Watershed Protection

One key element of water supply planning is the protection of the quality and usability of supplies we have already developed. The state should develop a program to encourage the development and implementation of watershed protection plans for existing supplies by the owners of the supplies. Elements of such a program could include:

- State grants or matching funding for studies.
- Development of guidance in the development and implementation of watershed protection plans.
- Technical assistance with the development and implementation of watershed protection plans.
- Seminars on watershed protection.
- Development of statewide databases of information that might be useful in watershed protection plans in a standard and consistent format. Such information might include:

- Land use
- Water quality data
- Roads
- Petroleum product pipelines
- Oil and gas wells
- Landfills
- Superfund sites and other potential sources of pollution
- Permitted wastewater discharges

Funding for NRCS Structures

Over the past 50 years, the U.S. Natural Resources Conservation Service (NRCS, formerly the Soil Conservation Service) has built a great many small dams for sediment control and flood control in Texas. The NRCS reservoirs also provide water for livestock and increase streamflows during low flow periods. The design life for the majority of the NRCS watershed dams is 50 years. Most of the projects were built in the 1950s and 1960s and are nearing the end of their design life. Many of the NRCS structures are in need of maintenance or repair in order to extend the life of the dams. There is legislation under consideration in the U.S. Congress to provide federal funding for renovating and upgrading NRCS flood control structures. The Region C Water Planning Group recommends that the State of Texas seek federal funding to improve and maintain NRCS structures.

In addition, there are some watersheds where local agencies can work with NRCS to develop additional sediment and flood control structures and implement other measures to control erosion. For example, the Tarrant Regional Water District is working with the NRCS to establish erosion control structures in the West Fork watershed. The West Fork Watershed Committee has worked to re-activate the NRCS watershed management program and to secure funding for the project. The state of Texas should seek to extend existing NRCS programs to assist with the development of erosion and sediment control programs.

Maintenance and Construction of Stock Ponds

The dry conditions of recent years have resulted in localized shortages of water for livestock across the state. One way to address these shortages is to develop stock ponds to capture runoff and hold it to provide water in dry periods. The costs of maintaining and building stock ponds can be quite high. State assistance and funding should be made available to help build and maintain stock ponds eligible for agricultural exemption status. Funding for building, improving, dredging, and increasing capacities of stock ponds can help ensure sufficient water supply for livestock.

Survey on Agricultural Water Use

The Texas Agricultural Statistics Service sends out a survey to farmers and ranchers across Texas. Currently, no questions regarding water supply are asked in this survey. Questions could be added to the survey to help quantify the amount of water being used for livestock and irrigation and to identify needed water supply improvements. Potential questions include:

- Do you use groundwater or surface water for your ranch/farm?
- If you are using groundwater:
  - What aquifer(s) are you pumping?
  - What is your total pumping capacity?
  - How deep are your water wells?
- If you are using surface water:
  - How many stock tanks do you have?
  - What is the capacity of each stock tank?
- Are you currently experiencing water shortages?
- How many head of livestock are you watering?
- How many acres of each crop are you irrigating?

Including questions on water supply in the Texas Agricultural Statistics Service survey could improve the basic data available on water use for agriculture and help with future water supply planning.

6.5 Recommendations for Ecologically Unique River and Stream Segments

As part of the Senate Bill One planning process, regional water planning groups are asked to make recommendations for designation of unique stream segments. The Texas Parks and Wildlife Department (TPWD) recommended certain specific stream segments in Region C for designation as unique stream segments. Table 6.1 lists segments recommended by TPWD in *Ecologically Significant River and Stream Segments of Region C, Regional Water Planning Area*[73] .That report included information intended to support designation of the recommended segments. TPWD also submitted a list of other segments recommended for designation with limited supporting information[74]. Those segments are listed in Table 6.2.

The Region C Water Planning Group recommends against designation of any unique stream segments in Region C because of the uncertain implications of such designation. The legislature should clarify the intent and impact of the unique stream segment designation. Specific questions that should be addressed by the legislature are outlined in Section 6.2 above.

6.6 Recommendations for Unique Sites for Reservoir Construction

Section 357.9 of the Texas Water Development Board (TWDB) regional water planning guidelines [1] allows a regional water planning group to recommend unique sites for reservoir construction:

> **"357.9. Unique Sites for Reservoir Construction.** A regional water planning group may recommend sites of unique value for construction of reservoirs by including descriptions of the sites, reasons for the unique designation and expected beneficiaries of the water supply to be developed at the site. The following criteria shall be used to determine if a site is unique for reservoir construction:
>
> (1) site-specific reservoir development is recommended as a specific water management strategy or in an alternative long-term scenario in an adopted regional water plan; or

Table 6.1

Texas Parks and Wildlife Department Recommendations for Designation as Ecologically Unique River and Stream Segments from *Ecologically Significant River and Stream Segments of Region C, Regional Water Planning Area*[73]

River or Stream Segment	Description	Basin	County	TPWD Reasons for Designation[a]				
				Biological Function	**Hydrologic Function**	**Riparian Conservation Area**	**High Water Quality/Aesthetic Value**	**Endangered Species/ Unique Communities**
Bois d'Arc Creek	Entire length	Red	Fannin	X	X	X		
Brazos River	Parker/Palo Pinto county line to F.M. 2580	Brazos	Parker	X			X	X
Buffalo/Linn Creek	Vicinity of confluence	Trinity	Freestone	X	X			
Clear Creek	Denton/ Cooke county line to confluence with Elm Fork Trinity River	Trinity	Denton				X	
Coffee Mill Creek	Entire length	Red	Fannin			X		
Elm Fork Trinity River (Denton County)	Lake Ray Roberts to U.S. 380	Trinity	Denton			X	X	
Elm Fork Trinity River (Dallas County)	California Crossing Road to confluence with West Fork Trinity River	Trinity	Dallas			X	X	
Lost Creek	Entire length	Trinity	Jack			X	X	
Purtis Creek[b]	Upstream from Henderson county line	Trinity	Henderson			X		
Trinity River	MacArthur Boulevard to Interstate 45	Trinity	Dallas			X	X	

[a] The criteria listed are from Texas Administration Code Section 357.8. The Texas Parks and Wildlife feels that their recommended reaches meet the criteria marked with an X.
[b] The reach of Purtis Creek recommended for designation by TPWD is in Region D rather than Region C.

Table 6.2

Other Texas Parks and Wildlife Department Suggestions for Designation as Ecologically Unique River and Stream Segments

River or Stream Segment	Basin	County
Red River - Fannin County	Red	Fannin
Red River - Grayson County	Red	Grayson
Red River - Cooke County	Red	Cooke
North Fish Creek	Red	Cooke
South Fish Creek	Red	Cooke
North Sulphur River	Sulphur	Fannin
Beans Creek	Trinity	Jack
Big Creek	Trinity	Wise
Red Oak Creek	Trinity	Ellis
Rowlett Creek	Trinity	Collin

(2) the location, hydrologic, geologic, topographic, water availability, water quality, environmental, cultural, and current development characteristics, or other pertinent factors make the site uniquely suited for :

(A) reservoir development to provide water supply for the current planning period; or

(B) where it might reasonably be needed to meet needs beyond the 50-year planning period."

This section presents the Region C Water Planning Group's recommendations for unique sites for reservoir development and the reasons for the recommendations. The Region C Water Planning Group recommends designation of the following four unique sites for reservoir development:

- Marvin Nichols I site on the Sulphur River in Red River, Bowie, Titus, and Franklin Counties
- Lower Bois d'Arc Creek (New Bonham) site on Bois d'Arc Creek in Fannin County
- Muenster site on Brushy Elm Creek in Cooke County
- Tehuacana site on Tehuacana Creek in Freestone County.

These sites and the reasons for designating them as unique reservoir sites are discussed below.

Marvin Nichols I

Description of the Site. The Marvin Nichols I site is located on the Sulphur River upstream from its confluence with White Oak Creek. The dam would be in Titus, Red River, and Bowie Counties, and the reservoir would also impound water in Franklin County. The proposed reservoir has been studied in the past and was included in the most recent Texas Water Plan as a source of water supply for Region C and Region D. The reservoir has been studied with a conservation pool elevation of 312.0, although a reservoir could be built at this location with conservation storage as high as 320.0.

With the top of conservation storage at elevation 312.0, the proposed reservoir would have a yield of 619,100 acre-feet per year and would flood 62,100 acres. The reservoir has a very large yield compared with other potential projects. The most significant environmental impact of the Marvin Nichols I project would be the inundation of habitat, including wetlands and bottomland hardwoods. The lake would inundate a portion of the Sulphur River Bottom West/Cuckoo Pond bottomland hardwoods area, which is designated as a Priority 1 area in the 1984 U.S. Fish and Wildlife Service *Bottomland Hardwood Protection Plan* (65). (A Priority 1 area is an "excellent quality bottomlands of high value to the key waterfowl species.") There are also lignite deposits and some oil and gas wells in the pool area of the lake.

Reasons for Unique Designation. Marvin Nichols I would provide a substantial portion of the projected water needs of Region C and Region D. It is included in the Region C water plan as a source of water for all of the major water providers in the region. North Texas Municipal Water District, Dallas Water Utilities, and Tarrant Regional Water District would participate in the project directly, with Fort Worth and the Trinity River Authority acquiring water from Tarrant Regional Water District. Through those major water providers, the reservoir would supply many of the water user groups in Region C.

Compared to the alternative of developing a number of other reservoirs in the Sulphur Basin (George Parkhouse I, George Parkhouse II, and Marvin Nichols II), Marvin Nichols I provides more water at a lower cost and with less environmental impact. The location, geologic, hydrologic, topographic, water availability, water quality, and current development characteristics make this site uniquely suited to provide a major water supply for Regions C and D.

Expected Beneficiaries of Water Supply. The expected beneficiaries of this project in Region C include the following water providers and water user groups:

- *Dallas Water Utilities and its customers*
  - *Multi-County* - Dallas, Carrollton, Cedar Hill, Combine, Glenn Heights, Grand Prairie, Grapevine, Lewisville, Ovilla
  - *Dallas County* - Addison, Balch Springs, Cockrell Hill, Coppell, De Soto, Duncanville, Farmers Branch, Hutchins, Irving, Lancaster, Seagoville, Wilmer, Dallas County Other, Dallas County Manufacturing, Dallas County Steam Electric Power, Dallas County Mining
  - *Denton County* - Denton, Flower Mound, The Colony, Denton County Other, Denton County Manufacturing
  - *Ellis County* - Oak Leaf
  - *Upper Trinity Water District and its current and potential customers*
    - *Multi-County* - Lewisville (also directly from Dallas)
    - *Collin County* - Celina, Prosper
    - *Cooke County* - Valley View, Cooke County Other
    - *Denton County* - Argyle, Aubrey, Bartonville, Copper Canyon, Corinth, Crossroads, Double Oak, Flower Mound (also directly from Dallas), Hebron, Hickory Creek, Highland Village, Justin, Krugerville, Krum, Lake Dallas, Lincoln Park, Northlake, Oak Point, Pilot Point, Ponder, Sanger, Shady Shores, Denton County Other (also directly from Dallas), Denton County Manufacturing (also directly from Dallas)
- *North Texas Municipal Water District and its customers*
  - *Multi-County* - Frisco, Garland, Plano, Richardson, Rowlett, Royse City, Sachse, Wylie
  - *Collin County* - Allen, Fairview, Farmersville, Lucas, McKinney, Melissa, Murphy, New Hope, Parker, Princeton, Prosper (also from UTRWD), Collin County Other, Collin County Manufacturing, Collin County Steam Electric Power
  - *Dallas County* - Mesquite, Sunnyvale, Dallas County Other (also from Dallas), Dallas County Manufacturing (also from Dallas), Dallas County Steam Electric Power (also from Dallas)
  - *Denton County* - Little Elm

- *Kaufman County* – Crandall, Forney, Kaufman, Oak Grove, Kaufman County Other, Kaufman County Manufacturing
- *Rockwall County* – Heath, Rockwall, Rockwall County Other, Rockwall County Manufacturing

- *Tarrant Regional Water District and its current and potential customers in Tarrant, Denton, Parker, Wise, and Johnson Counties*
  - *Multi-County* – Burleson (part in Region G, through Fort Worth), Mansfield (part in Region G), Azle, Briar, Grapevine (through TRA, also from Dallas), Newark, Grand Prairie (through Fort Worth, also from Dallas), Southlake (through Fort Worth)
  - *Denton County (through Fort Worth)* – Northlake (also from UTRWD), Roanoke, Trophy Club, Denton County Other
  - *Parker County* - Reno, Springtown, Weatherford, Parker County Steam Electric Power
    - *Through Weatherford* – Aledo, Annetta, Hudson Oaks, Willow Park, Parker County Other, Parker County Manufacturing
  - *Tarrant County* – Arlington, Benbrook, Blue Mound, Fort Worth, River Oaks, Tarrant County Irrigation, Tarrant County Mining, Tarrant County Steam Electric Power
    - *Through Fort Worth* – Benbrook (also direct from TRWD), Crowley, Dalworthington Gardens, Edgecliff Village, Everman, Forest Hill, Haltom City, Haslet, Hurst, Keller, Kennedale, Lake Worth Village, North Richland Hills, River Oaks (also direct from TRWD), Pantego, Richland Hills, Saginaw, Sansom Park Village, Watauga, Westworth Village, White Settlement, Tarrant County Other, Tarrant County Manufacturing
    - *Through Trinity River Authority* - Bedford, Colleyville, Euless, North Richland Hills (also through Fort Worth), Watauga (also through Fort Worth), Tarrant County Other (also through Fort Worth), Tarrant County Manufacturing (also through Fort Worth)
    - *Through Arlington* – Kennedale (also through Fort Worth), Pantego (also through Fort Worth)
  - *Wise County* - Aurora, Boyd, Bridgeport, Chico, Decatur, Rhome, Wise County Other, Wise County Manufacturing, Wise County Mining, Wise County Steam Electric Power.

Lower Bois d'Arc Creek (New Bonham)

Description of the Site. Lower Bois d'Arc Creek Reservoir would be located on Bois d'Arc Creek in Fannin County, immediately upstream from the Caddo National

Grassland. The proposed reservoir has been studied in the past with a conservation pool elevation of 534.0, and the Red River Compact gives Texas unlimited use of the waters of Bois d'Arc Creek upstream from the Lower Bois d'Arc Creek site.

With the top of conservation storage at elevation 534.0, the proposed reservoir would have a yield of 123,000 acre-feet per year and would flood 16,400 acres. The most significant environmental impacts of Lower Bois d'Arc Creek Reservoir would be the inundation of habitat, including wetlands and bottomland hardwoods. The lake would inundate the Bois d'Arc Creek bottomland hardwoods area, which is designated as a Priority 4 area in the 1984 U.S. Fish and Wildlife Service *Bottomland Hardwood Protection Plan* [65]. (A Priority 4 area is a "moderate quality bottomlands with minor waterfowl benefits.") The lake would have no direct impacts on the Caddo National Grasslands, but changes in flow patterns on Bois d'Arc Creek could have an indirect impact on the grasslands. In order to protect the grasslands, the Texas Parks and Wildlife Department nominated Bois d'Arc Creek for designation as an ecologically unique stream segment. Meeting the release requirements from the Texas Water Development Board consensus criteria for releases would minimize the downstream impacts of Lower Bois d'Arc Creek Reservoir.

Reasons for Unique Designation. The North Texas Municipal Water District would be the primary developer of the Lower Bois d'Arc Creek Reservoir, and it is assumed that the District would use 80 percent of the yield of the project. The remaining 20 percent of the yield would be reserved for use in the Red River Basin in the area of the project, particularly Fannin County. The North Texas Municipal Water District needs a major new supply by 2020, approximately 10 years earlier than the other major water providers in Region C. Because Lower Bois d'Arc Creek is smaller, costs less, and has less environmental impact than Marvin Nichols I, it could be developed by NTMWD alone and developed more quickly than the larger reservoir. Water in Lower Bois d'Arc Creek Reservoir would be relatively inexpensive in the lake and would also be relatively inexpensive delivered to the North Texas Municipal Water District.

The location, geologic, hydrologic, topographic, water availability, water quality, environmental, and current development characteristics make this site uniquely suited to provide water supply for Region C.

Expected Beneficiaries of Water Supply. The expected beneficiaries of this project include North Texas Municipal Water District and its customers and water user groups in Fannin County:

- *North Texas Municipal Water District and its customers*
  - *Multi-County* - Frisco, Garland, Plano, Richardson, Royse City, Sachse, Wylie, Rowlett
  - *Collin County* - Allen, Fairview, Farmersville, Lucas, McKinney, Melissa, Murphy, New Hope, Parker, Princeton, Prosper, Collin County Other, Collin County Manufacturing, Collin County Steam Electric Power
  - *Dallas County* - Mesquite, Sunnyvale, Dallas County Other (also from Dallas), Dallas County Manufacturing (also from Dallas), Dallas County Steam Electric Power (also from Dallas)
  - *Denton County* – Little Elm
  - *Kaufman County* – Crandall, Forney, Kaufman, Oak Grove, Kaufman County Other, Kaufman County Manufacturing
  - *Rockwall County* – Heath, Rockwall, Rockwall County Other, Rockwall County Manufacturing
- *Water User Groups in Fannin County* – Bonham, Honey Grove, Leonard, Savoy, Trenton, Fannin County Other, Fannin County Manufacturing.

Muenster

Description of the Site. Muenster Reservoir would be located on Brushy Elm Creek in Cooke County. The proposed reservoir has been permitted by the Texas Natural Resource Conservation District for impoundment of 4,700 acre-feet and diversion of 500 acre-feet per year for municipal use. The reservoir would flood 418 acres at the top of conservation storage. Because of its small size, the reservoir would have little environmental impact.

Reasons for Unique Designation. The Muenster Water District and the Natural Resource Conservation Service are developing Muenster Lake for municipal water supply, flood control, and recreation. The project has been permitted by the Texas Natural Resource Conservation Commission and approved by local voters. Muenster Lake would reduce Muenster's dependence on the Trinity aquifer, which is overused in Cooke County.

The location, geologic, hydrologic, topographic, water availability, water quality, environmental, and current development characteristics make this site uniquely suited to provide water supply for Region C.

Expected Beneficiaries of Water Supply. The expected beneficiaries of this project include Muenster, Cooke County Manufacturing, and Cooke County Other. The project would indirectly benefit other water user groups in Cooke County by reducing use from the Trinity aquifer.

Tehuacana

Description of the Site. Tehuacana Reservoir would be located on Tehuacana Creek in Freestone County, south of Richland-Chambers Reservoir. The proposed reservoir was included in the last state water plan as a source of supply for the Tarrant Regional Water District. The project has been part of TRWD's planning for many years, and it fits well with the District's system. The reservoir would have a conservation pool elevation of 315.0, the same as Richland-Chambers, and the two lakes would be connected by a channel.

With the top of conservation storage at elevation 315.0, the proposed reservoir would have a yield of 68,300 acre-feet per year and would flood 14,900 acres. The most significant environmental impacts of Tehuacana Reservoir would be the inundation of habitat, including wetlands and bottomland hardwoods. There are also lignite resources and oil and gas wells in the area that would be inundated by Tehuacana Reservoir.

Reasons for Unique Designation. Tehuacana Reservoir has been in the plans of the Tarrant Regional Water District for decades. The lake would be connected to Richland-Chambers Reservoir by a channel, allowing the water supply provided by Tehuacana to be pumped from Richland-Chambers. Development of Tehuacana could allow extension of the Tarrant Regional Water District project of diversions from the Trinity for additional water supply. Although this reservoir is not recommended for development before 2050 if other sources can be developed, it remains desirable as an alternative project and as a source of supply for growth after 2050.

The location, geologic, hydrologic, topographic, water availability, water quality, and current development characteristics make this site uniquely suited to provide water supply for Region C.

Expected Beneficiaries of Water Supply. The expected beneficiaries of this project would be Tarrant Regional Water District and its existing and potential customers as well as water user groups in Freestone County:

- *Multi-County* – Burleson (part in Region G, through Fort Worth), Mansfield (part in Region G), Azle, Briar, Grand Prairie (through Fort Worth), Grapevine (through TRA), Southlake (through Fort Worth), Mabank, Newark
- *Denton County (through Fort Worth)* – Northlake, Roanoke, Trophy Club, Denton County Other
- *Ellis County (through TRA)* – Ennis, Ferris, Italy, Maypearl, Midlothian, Palmer, Red Oak, Waxahachie, Ellis County Other, Ellis County Manufacturing
- *Freestone County* – Fairfield, Teague, Wortham, Freestone County Other, Freestone County Steam Electric Power
- *Henderson County* – Gun Barrel City, Malakoff, Payne Springs, Seven Points, Tool, Henderson County Other, Henderson County Steam Electric Power
- *Kaufman County* – Kemp, Kaufman County Other, Kaufman County Mining
- *Navarro County* – Corsicana
    - *Through Corsicana* – Blooming Grove, Dawson, Frost, Navarro County Other, Navarro County Manufacturing
- *Parker County* - Reno, Springtown, Weatherford, Parker County Steam Electric Power
    - *Through Weatherford* – Aledo, Annetta, Hudson Oaks, Willow Park, Parker County Other, Parker County Manufacturing
- *Tarrant County* – Arlington, Benbrook, Blue Mound, Fort Worth, River Oaks, Tarrant County Irrigation, Tarrant County Mining, Tarrant County Steam Electric Power
    - *Through Fort Worth* – Benbrook (also directly from TRWD), Crowley, Dalworthington Gardens, Edgecliff Village, Everman, Forest Hill, Haltom City, Haslet, Hurst, Keller, Kennedale, Lake Worth Village, North Richland Hills, Pantego, Richland Hills, River Oaks (also directly from TRWD), Saginaw, Sansom Park Village, Watauga, Westworth Village, White Settlement, Tarrant County Other, Tarrant County Manufacturing
    - *Through Trinity River Authority* - Bedford, Colleyville, Euless, North Richland Hills (also through Fort Worth), Watauga (also through Fort

Worth), Tarrant County Other (also through Fort Worth), Tarrant County Manufacturing (also through Fort Worth)

- *Through Arlington* – Kennedale (also through Fort Worth), Pantego (also through Fort Worth)

- *Wise County* - Aurora, Boyd, Bridgeport, Chico, Decatur, Rhome, Wise County Other, Wise County Manufacturing, Wise County Mining, Wise County Steam Electric Power.

Chapter 10

Water Management Strategies

The planning groups recommended more than 4,500 individual water management strategies to meet water supply needs resulting in a projected total of 9.0 million acre-feet per year of new supplies by 2060. Some of the recommended water management strategies are associated with supplies that are available but not physically connected or legally available.

Surface water management strategies, excluding major reservoirs, are projected to result in 3.3 million acre-feet per year.

Municipal water conservation strategies are projected to result in about 617,000 acre-feet per year by 2060.

Irrigation conservation strategies are projected to result in about 1.4 million acre-feet per year by 2060.

The planning groups recommended 14 new major reservoirs that are projected to generate approximately 1.1 million acre-feet per year by 2060.

Recommended water management strategies relying on groundwater are projected to result in about 800,000 acre-feet per year by 2060.

Recommended water reuse water management strategies are projected to result in about 1.3 million acre-feet per year by 2060.

Desalination projects recommended as water management strategies are projected to result in about 313,000 acre-feet per year by 2060.

The previous chapter demonstrates the need for additional water supplies in Texas. A key goal of regional water planning is to assess and recommend water management strategies to meet those needs. A recommended water management strategy is a specific plan to increase water supply or maximize existing supply to meet a specific need. Water management strategies include

- implementing water conservation and drought management;
- developing new groundwater and surface water supplies;
- expanding and improving management of existing water supplies, such as improving reservoir operations, reallocating reservoir storage space, using groundwater and surface water conjunctively, and conveying water from one area to another;
- water reuse; and
- implementing other, less traditional, approaches such as desalinating seawater and brackish water, controlling vegetation that consumes large volumes of water, practicing land stewardship, and weather modification.

Each of the 16 planning groups identified potentially feasible water management strategies for detailed analyses. As a result of their analyses, planning groups recommended a portfolio of water management strategies tailored to meet each region's water supply needs. Some strategies were carried forward from the prior planning cycle and reassessed due to changing conditions or new information. Other water management strategies considered by planning groups introduced new approaches to meeting water supply needs. In total, the planning groups recommended more than 4,500 individual water management strategies resulting in a total of 9.0 million acre-feet per year of new supplies by 2060.

This chapter provides information about the analyses of potentially feasible water management strategies and the resulting recommended water management strategies in the 2006 Regional

Water Plans and this state water plan. For presentation at the state level, recommended water management strategies in this chapter are categorized as water conservation, new or existing surface water supplies, new or existing groundwater supplies, conjunctive use of groundwater and surface water, water reuse, and desalination. In some cases, subcategories are presented for comparison within a major group.

10.1 Identification and Evaluation of Potential Water Management Strategies

Planning groups systematically evaluated each potentially feasible water management strategy before recommending specific water management strategies to meet water supply needs (Figure 10.1). These potentially feasible water management strategies were then assessed based on a variety of factors, including (1) how much water a strategy could produce and at what costs; (2) how the strategy could impact water quality and the state's water, agricultural, and natural resources; and (3) how reliable the strategy would be in providing water during drought conditions. Other factors considered by some planning groups included regulatory requirements, political and local issues, time requirements to implement a strategy, recreational impacts, and other socioeconomic benefits or impacts. The planning groups also identified how their plans would be consistent with the state's long-term goal of protecting Texas' water, agricultural, and natural resources. After a lengthy evaluation process, each planning group ultimately recommended specific water management strategies to meet identified water supply needs in their planning areas.

10.1.1 Quantity, Reliability, and Costs

Water quantity and reliability were among the key criteria used to assess strategies. Quantity refers to the amount of water that a given strategy would provide to water user groups during drought of record conditions. Reliability is an assessment of the availability of specified water quantities to users over time. If the quantity of water is available to the user all the time, then the strategy

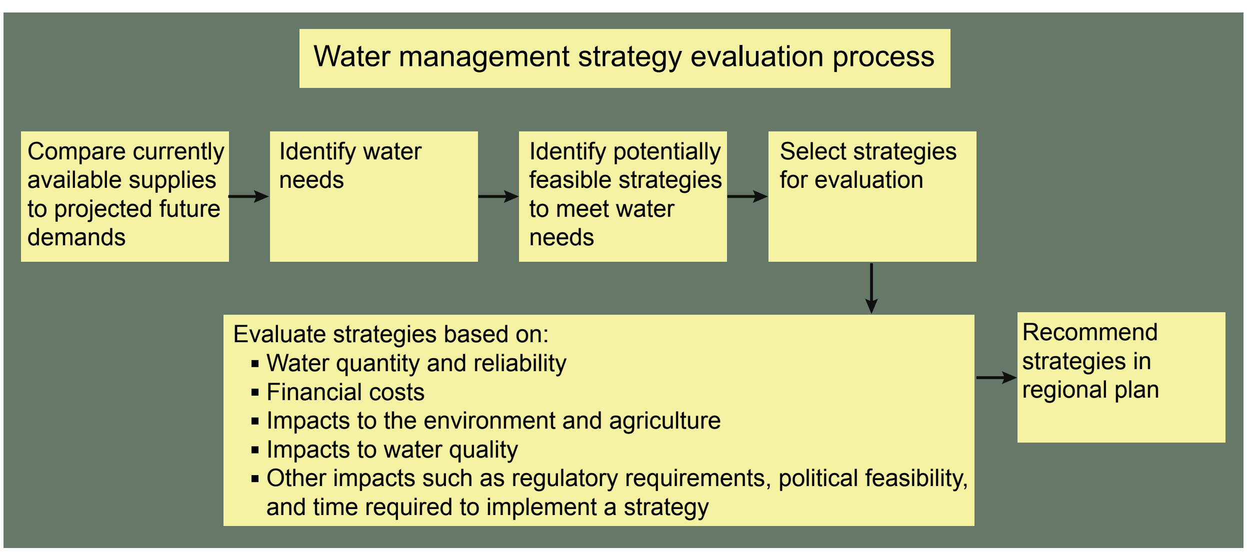


Figure 10.1.Water management strategy evaluation process.

has a high reliability. In contrast, if the quantity of water is contingent on other factors, reliability may be lower.

Financial costs were also an important factor considered when evaluating water management strategies. Planning groups estimated up-front capital requirements and annual costs. Capital costs included both the direct costs of constructing facilities, such as materials, labor, and equipment, and the indirect expenses associated with construction activities, such as costs for engineering studies, legal counsel, land acquisition, contingencies, environmental mitigation, interest during construction, and permitting fees. However, not all strategies have capital costs. For example, water conservation or water transfers using existing infrastructure often do not require up-front capital expenditures.

Annual costs were determined by including both the repayment of borrowed capital funds (debt service), the purchase of power and water, and the operating and maintenance expenses of facilities and water management programs. Debt service is the estimated annual costs of borrowed funds based on total capital costs and a prescribed finance rate and finance period based on the type of water management strategies being evaluated. Operating costs generally consist of labor and materials required to maintain a project in a given year and regular repair and/or replacement of depreciated equipment. Capital, operating, and maintenance costs were reported in year 2002 dollars. Planning groups were also required to consider project costs in terms of discounted present value when evaluating and comparing different strategies. The planning groups reported annual costs, and, thus, the unit cost per acre-foot for each decade for each water management strategy considered. These costs vary according to the type of project and many other factors, including whether or not a given strategy requires capital expenditures and debt service payments.

10.1.2 Impacts to the State's Water, Agricultural, and Natural Resources

Planning groups evaluated the potential impacts of each water management strategy on the state's water, agricultural, and natural resources.

In analyzing the impact of water management strategies on the state's water resources, the planning groups honored all existing water rights and contracts and considered conservation strategies for all water user groups with a water supply need. They also based their analyses of environmental flow needs on the environmental Consensus Planning Criteria or site-specific studies. In addition, planning groups were required to consider water management strategies to meet the water supply needs of irrigated agriculture and livestock production.

Planning groups also determined mitigation costs and quantified impacts for all water management strategies considered. They used a variety of approaches and assessment factors to quantify impacts of water management strategies on water, agricultural, and natural resources. Some used categorical assessments describing impacts as "high," "moderate," and "low." These ratings were based on existing data and the potential to avoid or mitigate impacts to agricultural and natural resources. For example, a "low" rating implied that impacts could be avoided or mitigated relatively

easily. In contrast, a "high" rating implied that impacts would be significant and mitigation requirements would be substantial. Other planning groups used a numerical rating that indicated the level of impact. Many planning groups based their ratings on factors such as the volume of discharges a strategy would produce or the number of irrigated acres lost. Another approach relied on identifying the number of endangered or threatened species listed in a county with a proposed water source. In general, most planning groups relied on existing information for evaluating the impacts of water management strategies on agricultural and natural resources.

10.1.3 Impacts on Water Quality

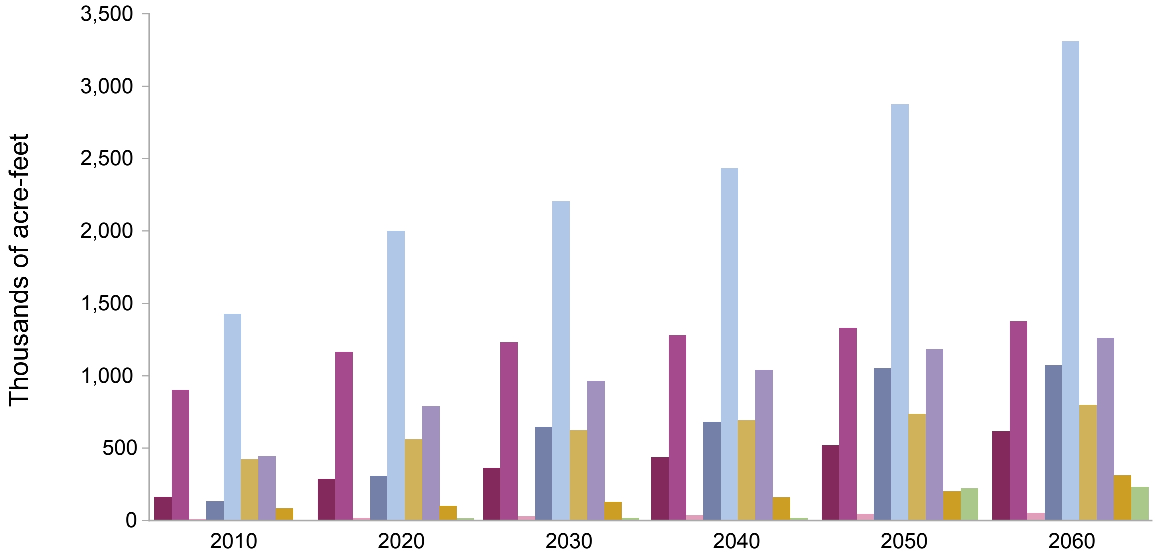
The planning groups also assessed how implementing water management strategies would affect water quality. All the planning groups identified key water quality parameters important for the use of water within their regions. These parameters were generally based on surface and groundwater quality standards and the list of impaired waters maintained and published by the Texas Commission on Environmental Quality. Other sources included water quality parameters and concerns identified by local and regional water management entities and concerns expressed by the public during the planning process. Key water quality parameters considered included bacteria, pH, dissolved oxygen, total suspended solids, temperature, nutrients, total dissolved solids, chlorides, nitrates, mercury, radionuclides, arsenic, salinity, and sediment.

10.2 Overview of Recommended Strategies

Planning groups recommended a variety of water management strategies to help meet needs in the future, including strategies that use water conservation, new or existing surface water supplies, new or existing groundwater supplies, conjunctive use of groundwater and surface water, water reuse, desalination, and land stewardship to provide additional water supplies. These strategies are projected to total 9.0 million acre-feet per year of new supplies by 2060 (Figure 10.2). Many strategies involve water conveyances from the source of water being recommended to meet a water supply need to the place of need (see section 10.2.8).

10.2.1 Water Conservation

Traditionally, water management strategies have focused on bringing water "into the pipe" through dams, reservoirs, and wells. In recent years, however, many communities have begun to focus on "end of the pipe" solutions through a common approach known as water conservation. At a fundamental level, water conservation involves managing existing water supplies to reduce demand and increase effciency of use. In other words, water managers and citizens collectively join forces to use less water in their homes and businesses and on their farms rather than building new projects to supply more of an already scarce resource. For water utilities and their customers, conservation programs are often more economical because they can postpone or eliminate the need for new infrastructure such as dams, wells, pipelines, and water treatment plants.



	2010	2020	2030	2040	2050	2060
Municipal conservation	164,672	286,226	364,924	437,714	519,441	616,679
Irrigation conservation	903,769	1,166,909	1,231,948	1,280,593	1,331,243	1,376,080
Other conservation[a]	10,636	20,276	30,130	37,115	45,128	54,092
New major reservoirs	132,863	306,663	646,993	681,498	1,051,128	1,072,128
Other surface water	1,426,449	2,002,895	2,204,909	2,432,839	2,873,271	3,309,990
Groundwater	424,429	563,081	622,381	691,671	736,609	799,209
Reuse	443,030	788,223	965,593	1,041,433	1,182,441	1,261,579
Desalination	84,295	101,522	130,164	159,922	200,866	312,887
Conjunctive use	1,131	15,244	18,700	18,701	223,090	231,567
Total	3,591,274	5,251,039	6,215,742	6,781,486	8,163,217	9,034,211

[a]Other conservation is associated with manufacturing, mining, and power industries.

Figure 10.2. Total new supply volumes generated by all recommended water management strategies over the planning period.

In recent years, the awareness and understanding of water conservation and water use efficiency has grown significantly in Texas. During the development of the 2006 Regional Water Plans, conservation has become increasingly important as a means to meet water supply needs.

A comparison of the 2007 State Water Plan to the 2002 State Water Plan shows the growing importance of water conservation in Texas. For example, recommended water management strategies for conservation in the 2002 State Water Plan generated 14 percent of the water needed to meet the state's needs in 2050—a total of about 990,000 acre-feet per year. In the 2007 State Water Plan, conservation accounts for nearly 23 percent of required water in 2060—a total of about 2 million acre-feet. These figures represent "active conservation," measures usually initiated by water utilities, individual businesses, residential water consumers, and agricultural producers to reduce water consumption. In addition, Texas will also save large amounts of water through as "passive water conservation." Passive water conservation involves water savings that result from state and federal legislation requiring plumbing manufacturers to sell more water-efficient plumbing fixtures, such as showerheads, faucets, and toilets. Active water conservation is above and beyond passive water conservation. TWDB estimates that passive conservation will reduce municipal water demand by 6.6 percent by 2060, which equals about 587,000 acre-feet, and statewide gallons per capita per day by 11.5 gallons.

Municipal Water Conservation

In state and regional water planning, municipal water conservation strategies focus on reducing residential, commercial, and institutional water use that typically involves water for drinking, cooking, cleaning, sanitation, air conditioning, and outdoor uses, such as landscape irrigation and swimming pools.

Municipal water conservation strategies focus on reducing these types of uses through a variety of social or technological approaches. Social approaches include changing water pricing structures to encourage more efficient water use and creating a greater awareness of the importance of conservation through promotional and educational campaigns. For example, programs such as bill explanation, plant tours, school programs, and educational and outreach activities have proven beneficial. Technological approaches include installing more efficient plumbing fixtures in homes and businesses.

In general, many communities throughout the state have taken great strides in developing municipal water conservation programs. Each city uses water conservation for different reasons. For example, the city of Austin wants to lower demand to meet a growing customer base; Corpus Christi hopes to postpone need for additional supply; El Paso has a limited long-term supply; and San Antonio has a limited existing water supply during drought conditions. However, water conservation is not limited to large cities. Many small- and medium-sized systems are also committed to increasing water use efficiency. To provide a unified conservation message, many smaller systems have partnered with

Table 10.1. Summary of recommended municipal water conservation management strategies in 2060

Region	New supplies from all recommended strategies (acre-feet per year)	New supplies from municipal conservation (acre-feet per year)	Percentage of all new supplies from municipal conservation	Estimated capital costs (millions of dollars)	Average annual unit costs per acre-foot of water [a] (dollars)
A	412,146	4,255	1	0.00	489
B	81,021	1,855	2	0.00	131
C	2,653,248	291,909	11	1.10	421
D	108,742	—	—	—	—
E	137,737	23,437	17	0.00	153
F	239,250	9,727	4	0.00	238
G	736,032	21,406	3	0.00	380
H	1,300,639	100,987	8	0.00	214
I	324,756	1,916	1	0.00	111
J	14,869	55	<1	0.00	419
K	861,930	51,315	6	0.00	209
L	732,779	72,566	10	0.00	442
M	807,587	24,412	3	8.77	141
N	149,496	2,415	2	0.00	333
O	441,511	10,424	2	0.00	863
P	32,468	—	—	—	—
Texas	9,034,211	616,679	7	9.87	234

Note: A dash indicates a value of zero.
[a]Reported figures are an average of unit costs in the first decade of strategy implementation and unit costs in 2060 weighted by the amount of water produced by a given strategy.

neighboring water systems in public-awareness campaigns to increase exposure, limit confusion, and reduce costs.

Municipal water conservation strategies identified by planning groups in their 2006 Regional Water Plans relied heavily on the Water Conservation Implementation Task Force's Best Management Practices Guide and include aggressive plumbing fixture replacement programs, water-efficient landscaping codes, water loss and leak detection programs, education and public awareness programs, rainwater harvesting, and changes in water rate structures. Fifteen of the 16 planning groups recommended municipal water conservation. Fourteen planning groups recommended it as a potential way to meet future municipal water needs (Table 10.1). In total, municipal water conservation strategies make up nearly 617,000 acre-feet (7 percent) of water generated by all recommend strategies by 2060.

When compared to the total volume of water generated by all recommended water management strategies, municipal water conservation strategies are an important source of water in many of the regions with large metropolitan areas, including Region E (17 percent), Region C (11 percent), Region H (8 percent), and Region L (10 percent). As noted previously, capital costs needed for implementing municipal water conservation programs are relatively small, amounting to about $9.9 million. Average operating costs per acre-feet of water generated from municipal water conservation strategies range from $111 per acre-foot in Region I to $863 in Region 0. The statewide average is $234 per acre-foot.

Agricultural Water Conservation

Irrigated agriculture has long been one of Texas' greatest water consumers. For example, irrigation currently accounts for about 60 percent of all water demand in the state, much of which consists of groundwater. By 2060, irrigation water demand is projected to decline to about 40 percent of total water demand in the state. Agricultural irrigation conservation programs have been widely promoted in areas of the state with large concentrations of irrigated crop production, such as the High Plains and Lower Rio Grande Valley.

Twelve of the 16 planning groups recommended agricultural water conservation as water management strategies to meet water needs including

- irrigation water use management, such as irrigation scheduling, volumetric measurement of water use, crop residue management, conservation tillage, and on-farm irrigation audits;
- land management systems, including furrow dikes, land leveling, conversion from irrigated to dry land farming, and brush control/management;
- on-farm delivery systems, such as lining of farm ditches, low pressure center pivot sprinkler systems, drip/micro irrigation systems, surge flow irrigation, and linear move sprinkler systems;
- water district delivery systems, including lining of district irrigation canals and replacing irrigation district and lateral canals with pipelines; and
- miscellaneous systems, such as water recovery and reuse.

In total, irrigation conservation strategies would generate nearly 1.4 million acre-feet of water in 2060, which equals about 37 percent of all irrigation water needs (Table 10.2). When compared to the total volume of water generated by all recommended water management strategies, agricultural water conservation is an important source of water where agriculture is a major economic sector. For example, Region A, Region O, and Region M collectively produce about 80 percent of irrigated crops in the state, with an economic value of around $1.5 billion annually. In total, these three planning groups recommended irrigation conservation strategies that would generate approximately 1 million acre-feet of water by 2060 (76 percent of the total water generated by irrigation conservation strategies in the state). Regions K, H, and J, which also produce substantial amounts of irrigated crops, adopted irrigation conservation strategies generating 222,333 acre-feet by 2060. Estimated capital costs for irrigation con-

Table 10.2. Summary of recommended irrigation water conservation management strategies in 2060

Region	New supplies from all recommended strategies (acre-feet per year)	New supplies from irrigation conservation (acre-feet per year)	Percentage of all new supplies from irrigation conservation	Estimated capital costs (millions of dollars)	Average annual unit costs per acre-foot of water[a] (dollars)
A	412,146	282,549	69	144.97	5
B	81,021	14,607	18	58.50	216
C	2,653,248	3,121	<1	0.00	211
D	108,742	–	–	–	–
E	137,737	–	–	–	–
F	239,250	72,247	30	43.15	51
G	736,032	8,027	1	0.00	154
H	1,300,639	77,881	6	0.62	83
I	324,756	–	–	–	–
J	14,869	1,452	10	<0.01	47
K	861,930	143,000	17	2.90	1
L	732,779	7,477	1	0.00	107
M	807,587	438,011	54	325.40	173
N	149,496	342	<1	0.00	171
O	441,511	327,366	74	353.51	65
P	32,468	–	–	–	–
Texas	9,034,211	1,376,080	15	929.06	77

Note: Dashes indicate a value of zero.
[a]Reported figures are an average of unit costs in the first decade of strategy implementation and unit costs in 2060 weighted by the amount of water produced by a given strategy.

servation are $929 million, and average operating costs per acre-feet of water generated range from $1 per acre-feet in Region K to $216 in Region B.

While many planning groups have adopted agricultural water conservation management strategies as a way to meet agricultural needs, implementing these strategies will be challenging for a variety of reasons. One overarching constraint, however, is economics. For on-farm water conservation practices, the cost per acre-foot for implementation, while lower than other water management strategies, is still cost-prohibitive for many individual farmers. In Region M, surface water rights and cost structures of irrigation districts may also provide disincentives for on-farm conservation. On the other hand, recent increases in energy costs are providing new economic incentives to adopt water conservation practices in areas that rely primarily on groundwater, such as Region A and Region O.

However, the immediate effect on farm income from these increases will limit farmers' abilities to invest in conservation practices that require capital expenditures.

To address economic and technical issues for implementing irrigation water conservation strategies, two large-scale, multiyear agricultural water conservation demonstration projects are underway in Region M and Region O to

- expedite the transfer of available water conservation technology to irrigated farms;
- develop comprehensive data using large-scale demonstration sites;
- assess the cost effectiveness of selected technologies; and
- evaluate and determine the impacts of conservation implementation on crop productivity, reduced irrigation water use, and available water supplies.

TWDB has developed partnerships to implement these projects, which will be used to support and enhance future agricultural conservation efforts. The projects represent major collaborative efforts by producers who volunteer their operations and time to the project to demonstrate cost-effective ways of implementing conservation strategies in the state. Several planning groups have also recommended continued and/or increased funding of federal and state financial and technical assistance for agricultural water conservation programs.

10.2.2 Strategies Using New and Existing Surface Water

Surface water management strategies generally consist of (1) building new reservoirs to impound surface waters or (2) managing existing surface waters through various approaches, such as moving water from one area to another through pipelines, purchasing additional water through contracts with major water providers, obtaining additional water rights, reallocating water in existing reservoirs, and changing the operating framework for a system of reservoirs (that is, system optimization).

In total, surface water strategies would produce about 4.4 million acre-feet of water in 2060 (Table 10.3). This represents a decrease from the 2002 State Water Plan of about 418,000 acre-feet. When compared to the total volume of water produced by all recommended strategies in the 2006 Regional Water Plans, surface water accounts for about 49 percent of the new supply for the state compared to nearly 66 percent in the 2002 State Water Plan. However, in some regions, surface water strategies make up the majority of new water, primarily in the eastern half of the state: Region C (61 percent), Region D (93 percent), Region G (70 percent), Region H (64 percent), Region I (92 percent), Region J (52 percent), and Region N (69 percent). Capital costs for surface water strategies total about $18 billion.

Planning groups recommended 14 new major reservoirs that would generate approximately 1.1 million acre-feet per year by 2060 (Table 10.3, Figure 10.3). These reservoirs account for about 12 percent of new water supplies at a capital cost of about $5 billion, which is 16 percent of total capital costs. The planning groups made the following recommendations:

Table 10.3. Summary of recommended surface water management strategies in 2060

Region	New supplies from all recommended strategies (acre-feet per year)	New supplies from surface water (acre-feet per year)		Percentage of all new supplies from surface water		Estimated capital costs (millions of dollars)		Average annual unit costs per acre-foot of water[a] (dollars)	
		New major reservoirs	Other surface water strategies	New major reservoirs	Other surface water strategies	New major reservoirs	Other surface water strategies	New major reservoirs	Other surface water strategies
A	412,146	–	3,750	–	1	–	72.27	–	1,122
B	81,021	–	51,875	–	64	–	89.08	–	198
C	2,653,248	746,540	874,102	28	33	3,338.57	6,461.72	354	331
D	108,742	–	100,636	–	93	–	4.82	–	362
E	137,737	–	20,000	–	15	–	103.49	–	408
F	239,250	–	90,075	–	38	–	30.12	–	36
G	736,032	36,520	477,101	5	65	89.06	493.58	186	208
H	1,300,639	129,520	707,393	10	54	567.79	4,206.81	223	88
I	324,756	75,700	222,875	23	69	387.11	190.36	643	197
J	14,869	–	7,690	–	52	–	6.65	–	124
K	861,930	–	398,215	–	46	–	15.23	–	66
L	732,779	–	98,214	–	13	–	853.37	–	887
M	807,587	20,643	169,460	3	21	66.55	230.62	537	539
N	149,496	42,005	61,615	28	41	304.21	186.55	684	493
O	441,511	21,200	26,500	5	6	150.76	230.58	688	1,186
P	32,468	–	489	–	2	–	–	–	na
Texas	9,034,211	1,072,128	3,309,990	12	37	4,904.05	13,175.25	374	254

Note: Dash indicates a value of zero and "na" indicates that data are not currently available.
[a]Reported figures are an average of unit costs in the first decade of strategy implementation and unit costs in 2060 weighted by the amount of water produced by a given strategy.

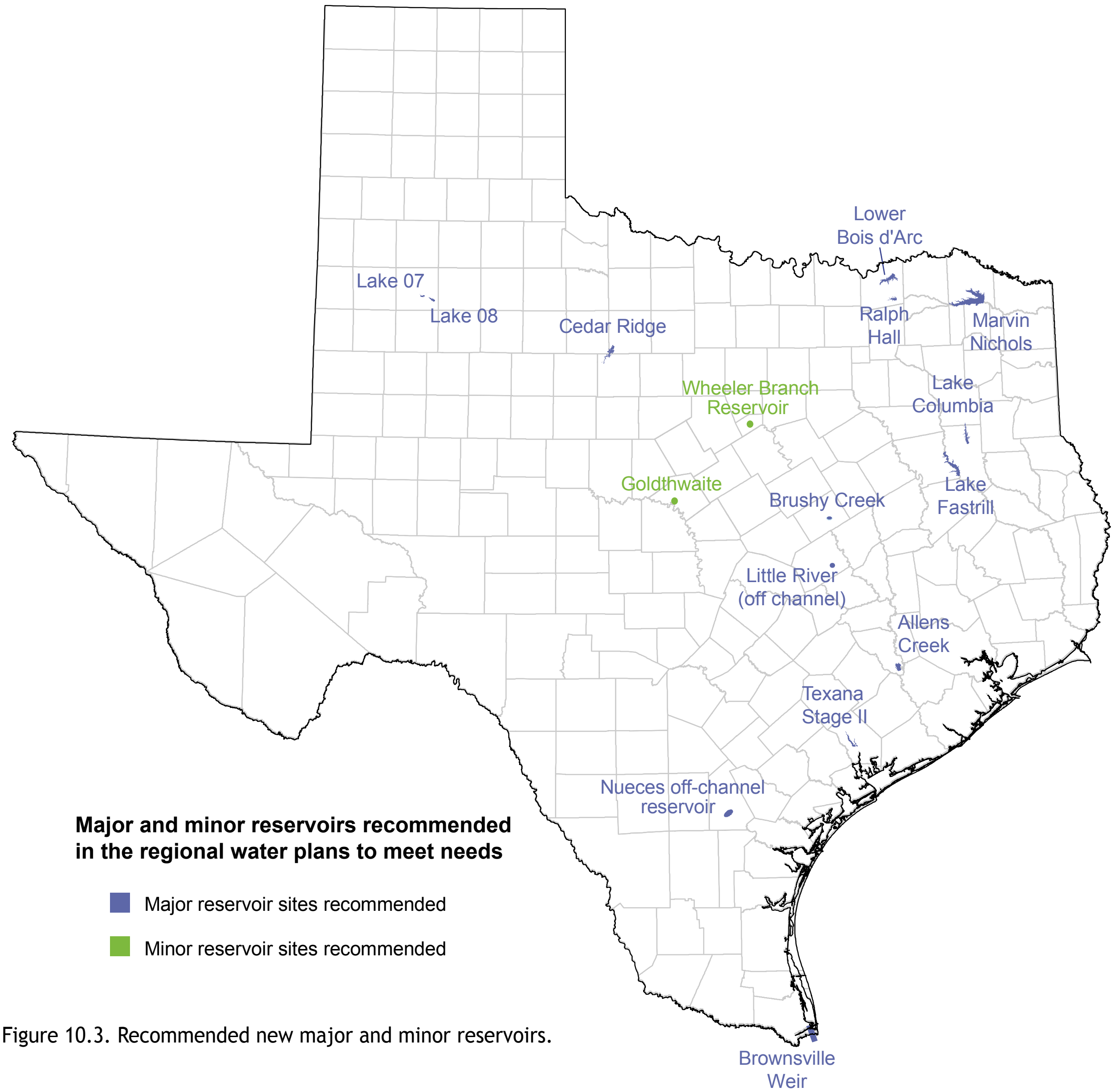


Figure 10.3. Recommended new major and minor reservoirs.

- Region C recommended four major reservoirs providing 28 percent of new supplies for the region in 2060 at a capital cost of about $3.3 billion
- Region G recommended two major reservoirs generating 5 percent of new supplies for the region at a capital cost of about $89 million
- Region H recommended two major reservoirs generating 10 percent of new supplies for the region at a capital cost of about $568 million
- Region I recommended one major reservoir providing 23 percent of new supplies for the region at a capital cost of about $387 million
- Region M recommended one major reservoir generating 3 percent of new supplies for the region at a capital cost of about $67 million
- Region N recommended two major reservoirs producing 28 percent of new supplies for the region at a capital cost of about $304 million
- Region O recommended two major reservoirs generating 5 percent of new supplies for the region at a capital cost of about $151 million

Average unit costs for reservoirs range from $186 per acre-foot in Region G to $688 per acre-foot in Region O. The statewide average unit cost for new major reservoirs is $374 per acre-foot. For other surface water strategies, average unit costs range anywhere from $36 per acre-foot in Region F to $1,186 per acre-foot in Region O, with the lower end reflecting costs of voluntary reallocation and purchases and the higher end representing costs of conveyance infrastructure.

The planning groups had the option of recommending unique reservoir sites and river and stream segments of unique ecological value for designation by the state legislature. A unique reservoir site is a location where a reservoir could be built. A river or stream segment of unique ecological value is a length of stream with distinctive ecological characteristics. Once designated as a unique reservoir site by the legislature, a state agency or political subdivision would not be allowed to purchase land or obtain an easement that would prevent the construction of a reservoir at the site. Similarly, once designated as a unique stream segment by the legislature, a state agency or political subdivision would not be allowed to finance the actual construction of a reservoir on that specific river or stream segment. This 2007 State Water Plan recommends that a total of 19 major and minor reservoir sites be designated by the legislature as unique reservoir sites. The planning groups recommended 11 unique reservoir sites (Figure 10.4), seven of which were recommended water management strategies. The remaining four recommended by planning groups as unique reservoir sites, Ringgold, Tehuacana, Little River, and Bedias, were not recommended as water management strategies to meet water supply needs over this planning horizon. TWDB is recommending eight additional unique reservoirs sites that were recommended by planning groups as water management strategies to meet water supply needs. TWDB's recommended sites include Cedar Ridge, Brushy Creek, Nueces River Off-Channel, Brownsville Weir, Wheeler Branch, and Goldthwaite. Fifteen river and stream segments of unique ecological value were recommended by two planning groups, seven for Region E (Figure 10.5) and eight for Region H (Figure 10.6).

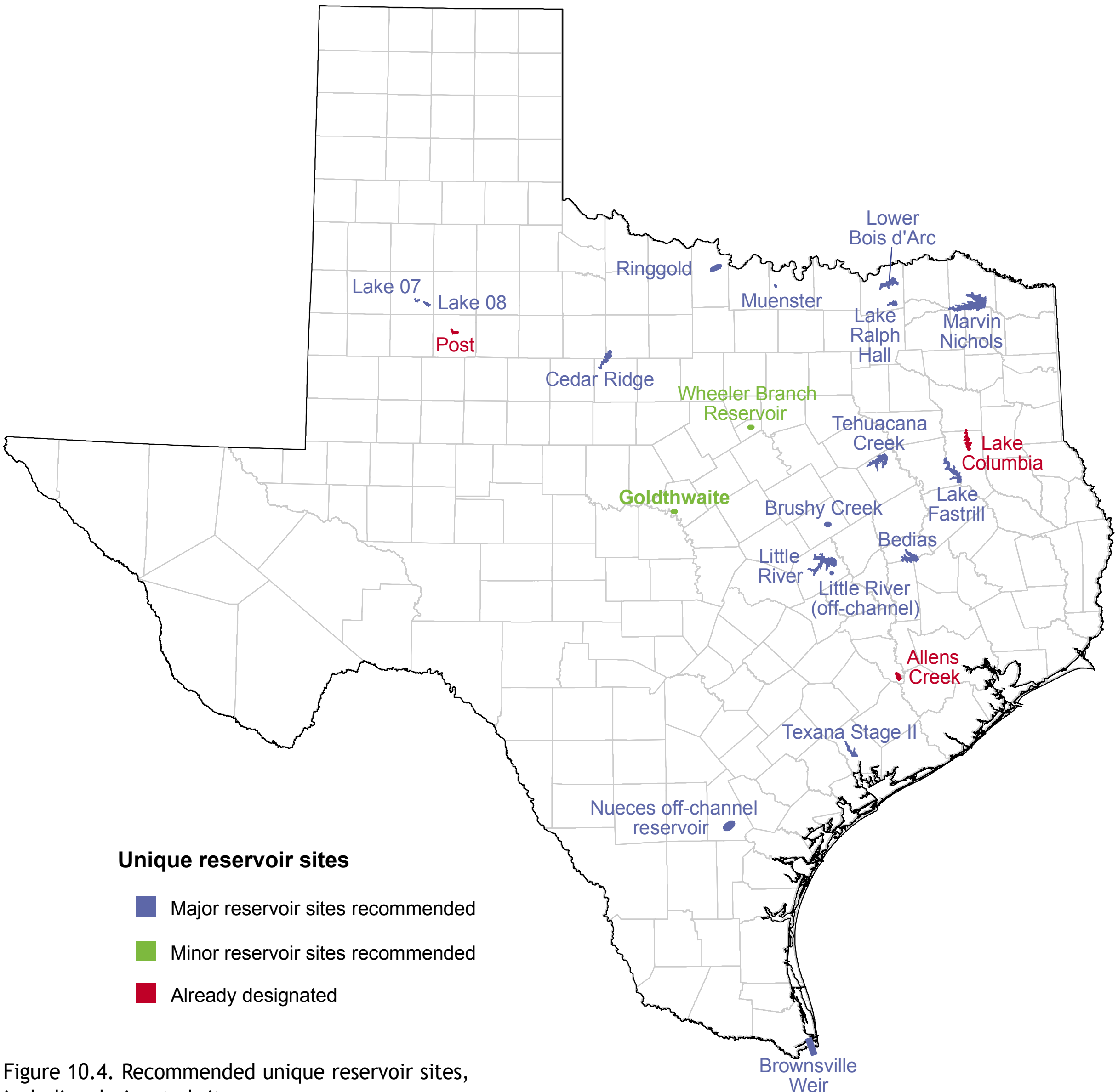


Figure 10.4. Recommended unique reservoir sites, including designated sites.

10.2.3 Strategies Using Groundwater

Recommended water management strategies using groundwater involve one or a combination of the following: (1) installing new wells; (2) increasing pumping from existing wells; (3) installing supplemental wells; (4) temporarily overdrafting of aquifers during drought conditions to supplement water supplies; (5) expanding treatment plants to make groundwater supplies meet water quality standards; and (6) reallocating and/

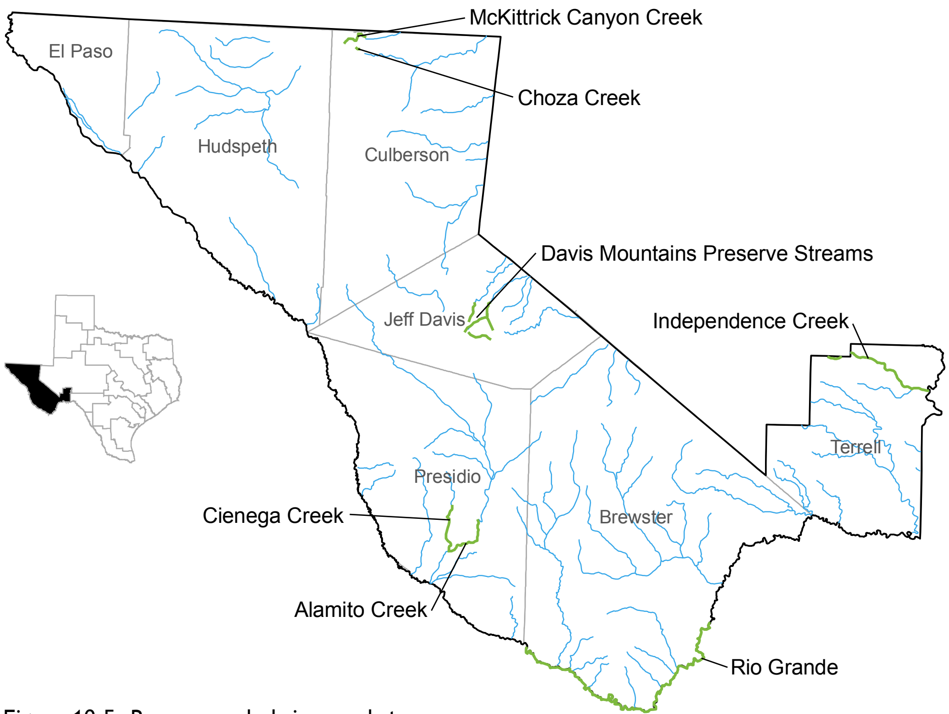


Figure 10.5. Recommended river and stream segments of unique ecological value in Region E.

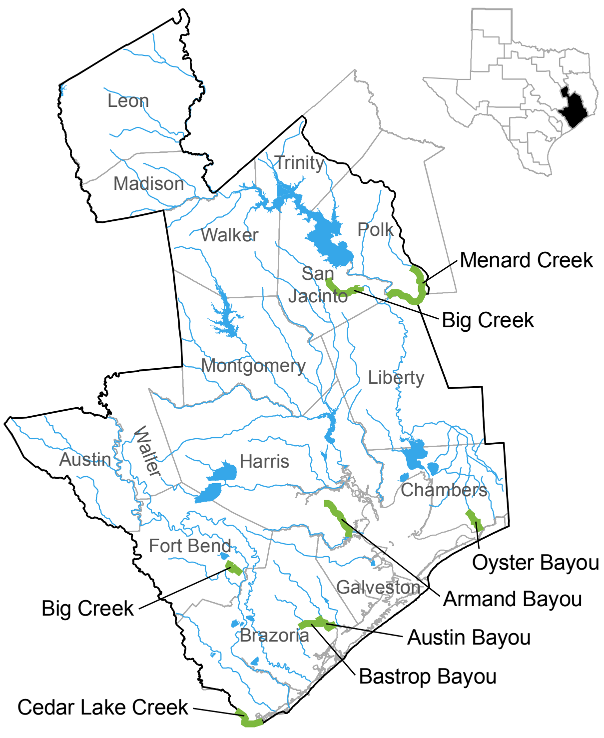


Figure 10.6. Recommended river and stream segments of unique ecological value in Region H.

or transferring groundwater supplies from areas where projections indicate that surplus groundwater will exist to areas with water needs.

Water management strategies relying on groundwater account for about 9 percent of the total projected water volume to be provided by all recommended water management strategies on a statewide basis in 2060, about 0.8 million acre-feet (Table 10.4). This represents an increase of about 20,000 acre-feet in 2050 from the 2002 State Water Plan. In terms of volume, recommended groundwater management strategies are the largest for Region L (206,111 acre-feet per year in 2060) and Region A (117,220 acre-feet per year in 2060). Total capital costs for groundwater strategies amount to about $2.3 billion, and average annual unit costs range from $33 per acre-foot in Region P to $634 per acre-foot in Region D. The statewide average unit cost for groundwater is $260 per acre-foot.

10.2.4 Strategies Using Water Reuse

Water reuse is an increasingly attractive water management strategy to meet water supply needs (see Chapter 8, Water Reuse). On a statewide basis, recommended water reuse strategies will generate about 1.3 million acre-feet in 2060 (Table 10.5), which accounts for about 14 percent of new water supplies to be provided from all recommended water management strategies. This represents a substantial increase when compared to the 2002 State Water Plan in which reuse made up about 6 percent (about 420,000 acre-feet) of new water supplies in 2050.

On a regional basis, Region C recommended reuse strategies that would produce about 720,000 acre-feet by 2060—nearly 27 percent of new water for the region. Reuse in Region H totals about 170,000 acre-feet per year by 2060, and regions K, L, and M collectively recommended over 240,000 acre-feet per year by 2060. Estimated capital costs for reuse strategies amount to about $4.0 billion, and average annual unit costs range from $100 to $1,259 per acre-foot of water generated, with a statewide average of $248 per acre-foot.

10.2.5 Strategies Using Desalination

Simply put, desalination is converting saline water to usable water. Today, desalination technology has been proven both reliable and cost effective in areas where water is scarce. Eight planning groups recommended desalinating brackish groundwater or seawater as a water management strategy. In total, recommended desalination projects would create about 313,000 acre-feet per year of new water supplies by 2060, with 44 percent of this water coming from seawater desalination and 56 percent coming from brackish groundwater desalination (Table 10.6). Desalination accounts for about 3 percent of all new water supplies from recommended water management strategies in 2060. Capital costs to implement recommended desalination water management strategies total about $2.6 billion. Average annual costs per acre-foot range from $768 to $1,390 for seawater desalination and $429 to $953 for brackish groundwater desalination.

10.2.6 Strategies Using Conjunctive Use

Conjunctive use water management strategies involve the combined use of groundwater and surface water in a way that optimizes the beneficial characteristics of each source. An example

Table 10.4. Summary of recommended groundwater management strategies in 2060

Region	New supplies from all recommended strategies (acre-feet per year)	New supplies from groundwater (acre-feet per year)	Percentage of all new supplies from groundwater	Estimated capital costs (millions of dollars)	Average annual unit costs per acre-foot of water[a] (dollars)
A	412,146	117,220	28	343.34	193
B	81,021	1,550	2	5.09	590
C	2,653,248	12,639	<1	449.53	96
D	108,742	7,806	7	27.76	634
E	137,737	26,191	19	36.78	204
F	239,250	38,270	16	251.83	490
G	736,032	41,075	6	86.71	443
H	1,300,639	90,993	7	173.15	122
I	324,756	21,589	7	32.36	183
J	14,869	5,672	38	7.72	120
K	861,930	95,742	11	65.45	93
L	732,779	206,111	28	713.96	399
M	807,587	31,416	4	43.98	359
N	149,496	20,535	14	48.34	537
O	441,511	50,421	11	43.99	136
P	32,468	31,979	98	0.00	33
Texas	9,034,211	799,209	9	2,329.99	260

[a]Reported figures are an average of unit costs in the first decade of strategy implementation and unit costs in 2060 weighted by the amount of water produced by a given strategy.

of conjunctive use is when water providers use surface water as their primary source of water supply and groundwater to meet peak day needs or to supplement supply during times of drought. Region K, Region L, and Region G recommended conjunctive use strategies in their regional water plans. New supplies provided from these recommended water management strategies in Region L would total about 180,000 acre-feet per year by 2060. This includes water provided from the Lower Colorado River Authority and San Antonio Water System Water Project that is projected to generate 150,000 acre-feet of new water supplies by 2060 through conjunctive use of groundwater from the Gulf Coast Aquifer and surface water

Table 10.5. Summary of recommended water reuse management strategies in 2060

Region	New supplies from all recommended strategies (acre-feet per year)	New supplies from water reuse (acre-feet per year)	Percentage of all new supplies from water reuse	Estimated capital costs (millions of dollars)	Average annual unit costs per acre-foot of water[a] (dollars)
A	412,146	2,700	1	1.83	100
B	81,021	11,134	14	49.60	761
C	2,653,248	722,320	27	2,952.01	113
D	108,742	300	<1	0.00	na
E	137,737	18,109	13	45.84	249
F	239,250	12,710	5	100.89	627
G	736,032	81,728	11	103.68	320
H	1,300,639	165,865	13	256.45	561
I	324,756	2,676	1	3.6	214
J	14,869	–	–	–	–
K	861,930	144,090	17	178.06	268
L	732,779	51,676	7	189.31	449
M	807,587	45,781	6	52.39	559
N	149,496	250	<1	1.50	725
O	441,511	2,240	1	29.75	1,259
P	32,468	–	–	–	–
Texas	9,034,211	1,261,579	14	3,964.91	248

Note: Dash indicates a value of zero and “na” indicates that data are not currently available.
[a] Reported figures are an average of unit costs in the first decade of strategy implementation and unit costs in 2060 weighted by the amount of water produced by a given strategy.

supplies from the Colorado River. In Region G, conjunctive use strategies would produce about 54,000 acre-feet per year of new supplies by 2060. Capital costs for both regions are about $2.8 billion, and average annual unit costs are $749 per acre-foot in Region G and $1,244 per acre-foot in Region L.

10.2.7 Strategies Using Land Stewardship

One of the suggested water management strategies emerging in this round of water supply planning is voluntary land stewardship. There is a relationship between the condition of a watershed and the quality and quantity of water that percolates to aquifers or runs off to streams and rivers. In some parts of the state, it is thought that improving the condition of the watershed's vegetative cover can help clean and increase the amount of water for human use and the environment. Land stewardship practices that help control nuisance vegetation, maintain and restore suitable vegetation in riparian areas, reseed with native plants, maintain open space land and wildlife habitat, conserve wetlands, and control erosion through reduction of overgrazing will promote the health and efficiency of the state's watersheds and should be encouraged.

A component of land stewardship that has garnered much attention is brush control, which involves reducing vegetation that consumes large volumes of water that would otherwise recharge aquifers or flow in rivers and streams in many areas of the state. Region G recommended brush control as a water management strategy to meet irrigation needs; however, potential supplies generated by brush control are difficult to quantify and, as a result, are not included in their regional total.

10.2.8 Major Conveyances

To deliver water to areas with needs, several new water conveyance systems are included as a component of many water management strategies. These conveyance systems connect existing waters sources that are not currently physically available to a water user. Although determining precise conveyance routes was beyond the level of detail required for regional water planning, the general location of the recommended conveyance structures illustrates that most of the water supplies will be conveyed to larger urban areas of the state (Table 10.7, Figure 10.7).

Detailed information on planning group recommended water management strategies are included in Chapter 2, Appendix 2.1, and Volume III.

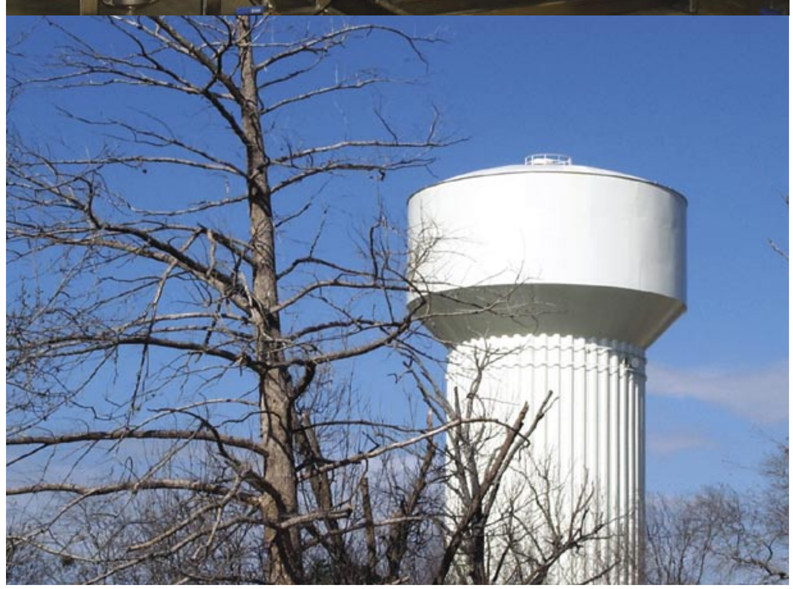


Table 10.6. Summary of recommended desalination water management strategies in 2060

Region	New supplies from all recommended strategies (acre-feet per year)	New supplies from desalination (acre-feet per year)		Percentage of all new supplies from desalination		Estimated capital costs (millions of dollars)		Average annual unit costs per acre-foot of water[a] (dollars)	
		Seawater desalination	Brackish desalination	Seawater desalination	Brackish desalination	Seawater desalination	Brackish desalination	Seawater desalination	Brackish desalination
A	412,146	–	–	–	–	–	–	–	–
B	81,021	–	–	–	–	–	–	–	–
C	2,653,248	–	–	–	–	–	–	–	–
D	108,742	–	–	–	–	–	–	–	–
E	137,737	–	50,000	–	36	–	502.74	–	953
F	239,250	–	16,221	–	7	–	131.45	–	599
G	736,032	–	–	–	–	–	–	–	–
H	1,300,639	28,000	–	2	–	255.70	–	1,300	–
I	324,756	–	–	–	–	–	–	–	–
J	14,869	–	–	–	–	–	–	–	–
K	861,930	–	29,568	–	3	–	96.54	–	429
L	732,779	84,012	5,662	11	1	891.32	93.41	1,390	903
M	807,587	7,902	69,962	1	9	15.94	342.47	768	537
N	149,496	18,200	–	12	–	248.92	–	1,341	–
O	441,511	–	3,360	–	1	–	10.05	–	506
P	32,468	–	–	–	–	–	–	–	–
Texas	9,034,211	138,114	174,773	2	2	1,411.88	1,176.66	1,351	671

Note: Dash indicates a value of zero.
[a]Reported figures are an average of unit costs in the first decade of strategy implementation and unit costs in 2060 weighted by the amount of water produced by a given strategy.

Table 10.7. Major water conveyances proposed by planning groups

ID	Conveyance from	To
1	Potter County	Amarillo
2	Roberts County	Amarillo
3	Palo Duro Reservoir	Hansford, Hutchinson, and Moore counties
4	Wichita Falls	Electra
5	Lake Kemp/Diversion System	Archer, Clay, and Wichita counties
6A	Toledo Bend Reservoir	Lake Fork
6B	Lake Fork	Cooper Lake then Lake Lavon
6C	Lake Fork	Lake Tawakoni then Cedar Creek Reservoir
7A	Marvin Nichols Reservoir	Lake Lavon
7B	Lake Lavon	Lewisville Lake
7C	Lewisville Lake	Eagle Mountain Lake
8A	Hugo Lake in southeast Oklahoma	Lavon Lake
8B	Lake Lavon	Lewisville Lake
8C	Lewisville Lake	Eagle Mountain Lake
9	Lake Wright Patman	Dallas Water Utilities
10	Richland-Chambers and Cedar Creek reservoirs	Tarrant Regional Water District
11	Lower Bois d'Arc Reservoir	North Texas Municipal Water District
12	Lake Fork	Dallas Water Utilities
13	Lake Texoma	North Texas Municipal Water District
14	Lake Ralph Hall	Denton and Collin counties
15	Lake Fastrill	Dallas Water Utilities
16	Lake Palestine	Dallas Water Utilities
17	Trinity River near Crandall	Lake Lavon
18	Hudspeth and Culberson counties	Dell City then El Paso
19	Winkler County	Odessa
20	Winkler County	Midland
21	Capitan Reef Aquifer	Odessa
22	Concho and McCulloch counties	San Angelo
23	Brazos River at Johnson County	Johnson County
24	Lake Whitney	Hill County
25	Brazos River at Grimes County	Grimes County
26	Milam County	Lake Granger
27	Lake Travis	Williamson County
28	Lake Fork	Rusk County
29	Kerr County	Kerrville
30	Lower Colorado River	Bexar County
31	Lower Guadalupe River	Hays and Kendall counties
32	Gonzales and Wilson counties	Bexar County
33	Bastrop, Caldwell, and Fayette counties	Hays County
34	Gonzales County/Lake Dunlap	Guadalupe and Bexar counties
35	Desalination plant	Bexar County
36	Wilson County	Bexar County
37	Choke Canyon Reservoir	Lake Corpus Christi
38	Corpus Christi	San Patricio County
39	Lower Colorado River	Lake Texana
40	Lake Alan Henry	Lubbock
41	Lubbock	Constructed wetlands on tributary of White River

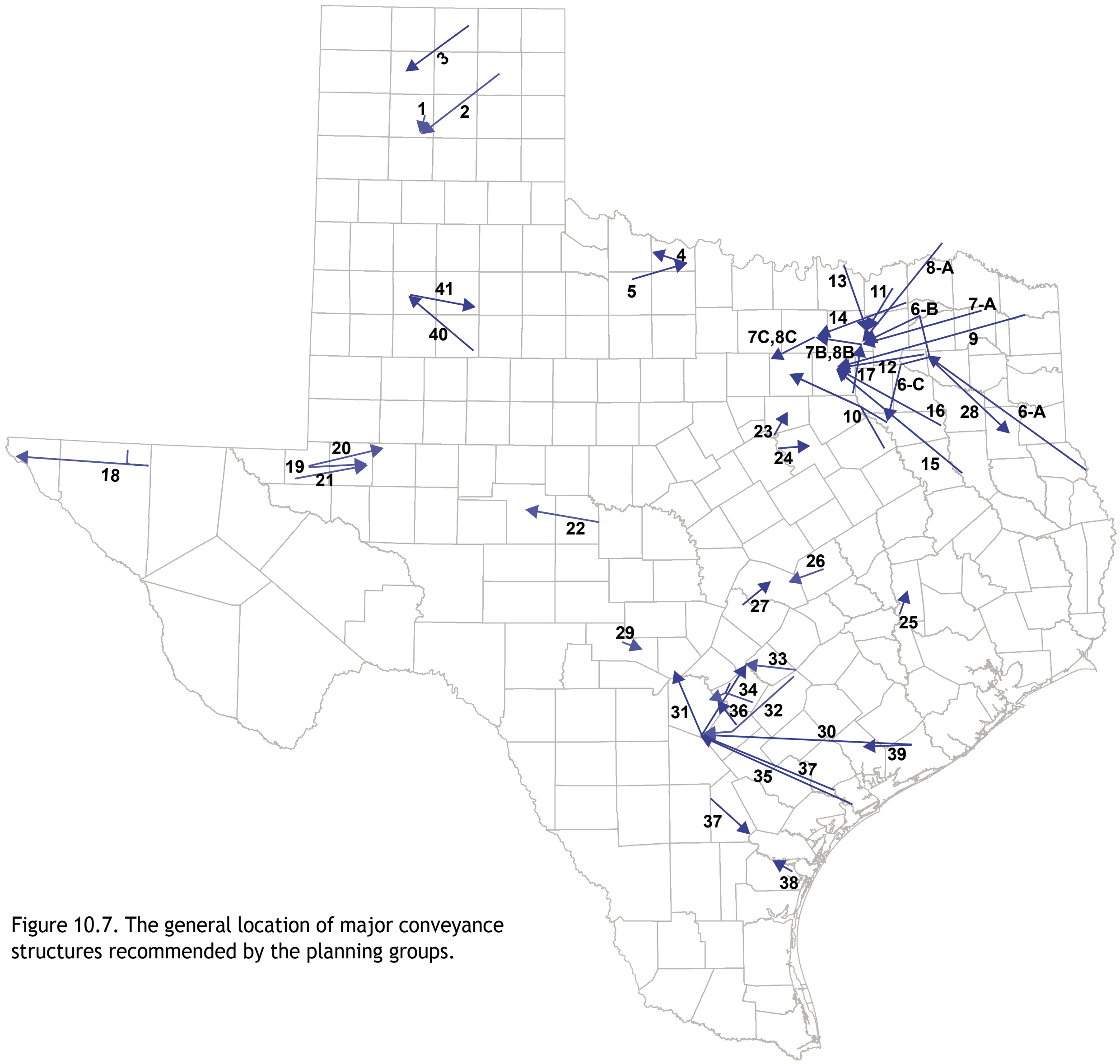


Figure 10.7. The general location of major conveyance structures recommended by the planning groups.

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EXECUTIVE SUMMARY

2006 REGION C WATER PLAN

JANUARY 2006

Executive Summary

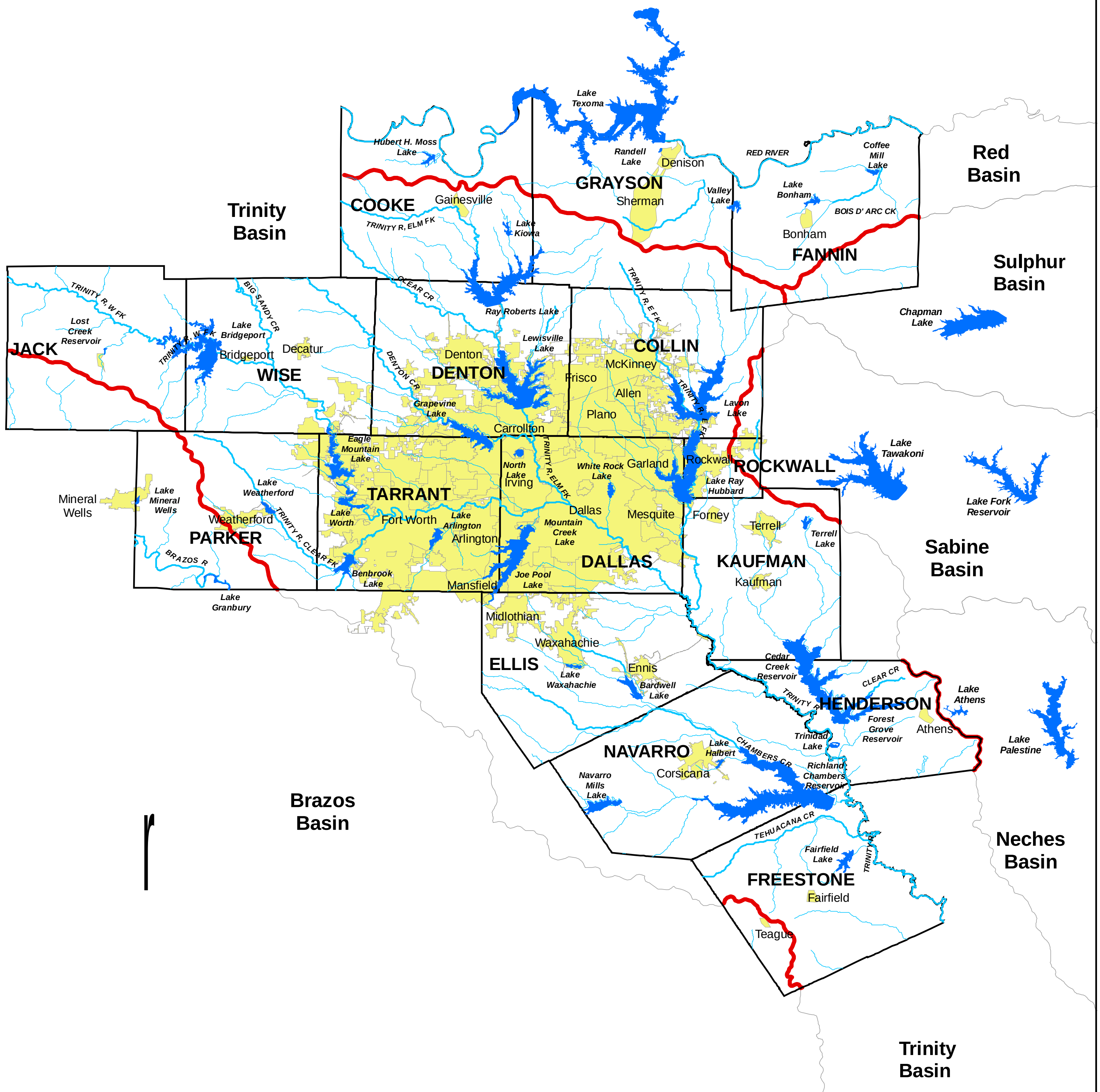
This report presents the *2006 Region C Water Plan* developed in the second round of the Senate Bill One regional water planning process. Region C covers all or part of 16 North Central Texas counties, as shown in Figure ES.1. The report presents the results of a five-year planning effort to develop a plan for water supply for the region through 2060.

The Region C water plan was developed under the direction of the 19-member Region C Water Planning Group. This regional water plan was adopted by the Region C Water Planning Group on December 5, 2005 and presented to the Texas Water Development Board in January 2006.

The *2006 Region C Water Plan* includes the following chapters:

1. Description of Region C
2. Population and Water Demand Projections
3. Analysis of Water Supply Currently Available to Region C
4. Identification, Evaluation and Selection of Water Management Strategies
   - 4A. Comparison of Current Water Supply and Projected Water Demand
   - 4B. Water Conservation and Reuse of Treated Wastewater Effluent in Region C
   - 4C. Methodology for Evaluation and Selection of Water Management Strategies
   - 4D. Evaluation of Major Water Management Strategies
   - 4E. Recommended Water Management Strategies for Wholesale Water Providers
   - 4F. Recommended Water Management Strategies for Water User Groups by County
5. Impacts of Recommended Water Management Strategies
6. Water Conservation and Drought Management Recommendations
7. Description of How the Regional Water Plan is Consistent with Long-Term Protection of the State's Water Resources, Agricultural Resources, and Natural Resources
8. Unique Stream Segments, Unique Reservoir Sites, and Legislative Recommendations
9. Infrastructure Funding Recommendations
10. Plan Approval Process and Public Participation

Figure ES.1
Region C and Major Outside Water Supplies
Currently Used in Region C

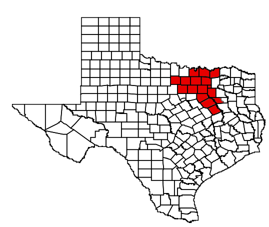


Legend

- City
- Streams
- Reservoirs
- Major Rivers
- River Basin Boundaries
- County Line

0 5 10 20 30

Scale in Miles



This Executive Summary focuses on current water needs and supplies in Region C, the projected need for water, the identification and selection of recommended water management strategies, and the costs and impacts of the selected strategies. Other elements of the plan are covered in the main text and the appendices.

ES.1   Current Water Needs and Supplies in Region C

As of the 2000 census, the population of Region C was 5,254,722, which represents 25.2 percent of Texas' total population. The two most populous counties in Region C, Dallas and Tarrant, have 70 percent of the region's population. Region C is heavily urbanized, with 81 percent of the population located in cities with populations in excess of 20,000 people.

Physical Setting

Most of Region C is in the upper portion of the Trinity River Basin, with smaller parts in the Red, Brazos, Sulphur, and Sabine River Basins. Figure ES.1 shows the major streams in Region C. Precipitation increases west to east in the region. The average runoff in the region increases from the west to the east, while evaporation is higher in the western part of Region C. The patterns of rainfall, runoff, and evaporation result in more abundant water supplies in the eastern part of Region C than in the west.

Thirty-four reservoirs in Region C have conservation storages in excess of 5,000 acre-feet. These reservoirs and others outside of Region C provide most of the region's water supply. Aquifers in the region include the Trinity, Carrizo-Wilcox, Woodbine, Nacatoch, and Queen City.

Water Use

Water use in Region C has increased significantly in recent years, primarily in response to increasing population and municipal demand. The regional water use in the year 2000 was 1,380,556 acre-feet. It is interesting to note that Region C, with 25.2 percent of Texas' population, had only 8.2 percent of the state's water use in 2000. About 85 percent of the current water use in Region C is for municipal supply, followed by manufacturing use and steam electric power generation.

Current Sources of Water Supply

Over 90 percent of the water use in Region C is supplied by surface water, but groundwater is an important source of supply, especially in rural areas. Most of the surface water supply in Region C comes from major reservoirs, including reservoirs in the region and reservoirs outside of Region C that supply water for the region. The Trinity aquifer is by far the largest source of groundwater in Region C, with the Woodbine, Carrizo-Wilcox and other minor aquifers also used. The current use of groundwater exceeds the reliable long-term supply available in some parts of Region C.

Over half of the water used for municipal supply in Region C is discharged as treated effluent from wastewater treatment plants, making wastewater reclamation and reuse a potentially significant source of additional water supply for the region. At present, only a fraction of the region's treated wastewater is actually reclaimed and reused in the region. Many of the region's water suppliers are considering reuse projects. It is clear that the reuse of treated wastewater will be a significant source of future water supplies for Region C.

Water Providers in Region C

Water providers in Region C include 35 wholesale water providers and 351 water user groups. In 2000, the three largest wholesale water providers in Region C (Dallas Water Utilities, Tarrant Regional Water District, and North Texas Municipal Water District) provided 75 percent of the water used in the region. Cities and towns provide most of the retail water service in Region C.

ES.2 Projected Need for Water

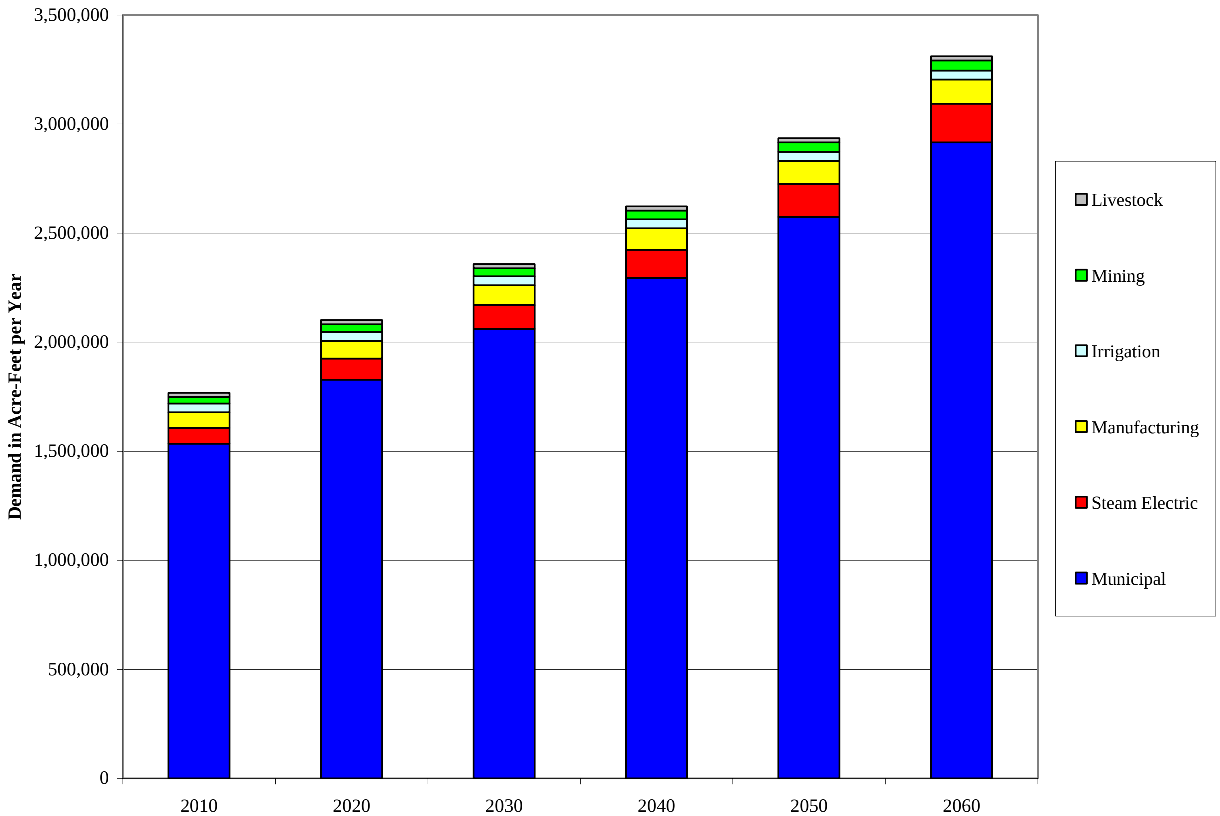
Population Projections

The population of Region C is projected to grow from 5,254,722 in the year 2000 to 9,093,847 in 2030 and 13,087,849 in 2060. These region-wide projections match regional numbers provided by the Texas Water Development Board, as required by TWDB planning guidelines. This projection reflects a substantial slowing in the rate of growth that has been experienced in Region C over the last 50 years. The projected 2030 population is 0.5 percent lower than an independent projection by the North Central Texas Council of Governments, indicating extremely close agreement. The distribution of the projected population by county and city is discussed in Chapter 2.

Demand Projections

Figure ES.2 shows the projected demands for water in Region C, which increase to 2.4 million acre-feet per year in 2030 and 3.3 million acre-feet per year in 2060. As has been the case historically, municipal demands are projected to make up the majority of the water use in Region C.

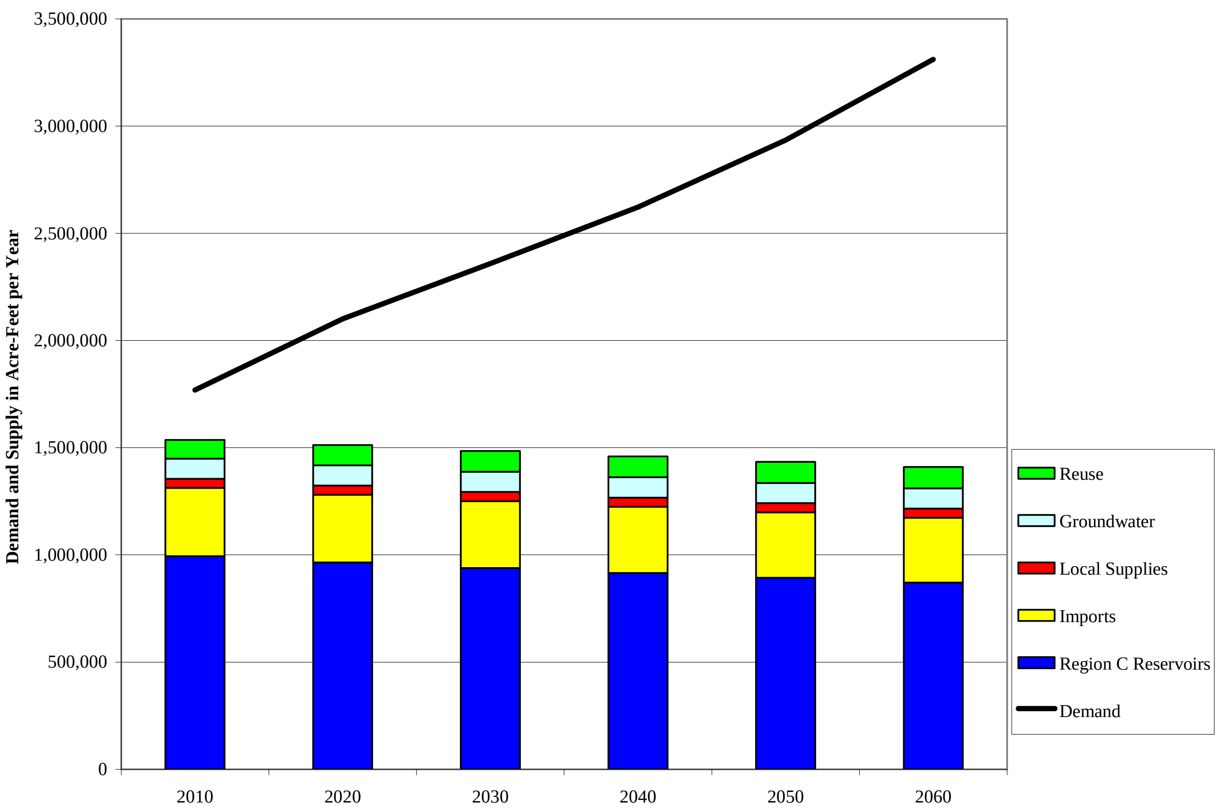
Figure ES.2
Projected Region C Demands



The Comparison of Supply and Demand

Figure ES.3 shows a comparison of supplies currently available to Region C and projected demands. Currently available supplies decline slightly over time due to sedimentation in reservoirs, reaching less than 1.4 million acre-feet per year by 2060. With the projected 2060 demand of 3.3 million acre-feet per year, the region has a shortage of 1.9 million acre-feet per year by 2060. There are about 500,000 acre-feet per year in supplies committed to Region C that are not yet connected. Meeting the projected shortage and leaving a reasonable surplus of planned supplies over projected needs will require the development of significant new water supplies for Region C over the next 55 years.

Figure ES.3
Comparison of Currently Available Supplies and Projected Demands



Socio-Economic Impacts of Not Meeting Projected Water Needs

The Texas Water Development Board has conducted a preliminary analysis of the impacts of not meeting the projected demands. The analysis indicates that a severe drought occurring in a single year would:

- Reduce the projected 2060 population by 1,007,000, a reduction of 7.7 percent.
- Reduce the projected 2060 employment by 691,060 jobs, a reduction of 17 percent.
- Reduce the projected income in 2060 by $58.8 billion, a reduction of 21 percent.

The lost income and tax revenues from failing to take steps to provide sufficient water for the projected growth in Region C are nearly $161 billion.

ES.3 Identification and Selection of Water Management Strategies

The Region C Water Planning Group identified and evaluated a wide variety of potentially feasible water management strategies in developing this plan. Water supply availability, costs and environmental impacts were determined for conservation and reuse efforts, the connection of existing supplies, and the development of new supplies. Almost every strategy suggested to the region during the planning process was analyzed.

As required by TWDB regulations, the evaluation of water management strategies was an equitable comparison of all feasible strategies and considered the following factors:

- Evaluation of quantity, reliability, and cost of water delivered and treated
- Environmental factors
- Impacts on other water resources and on threats to agricultural and natural resources
- Other factors deemed relevant by the planning group (including consistency with the plans of water providers in the region)
- Consideration of interbasin transfer requirements and third party impacts of voluntary redistributions of water.

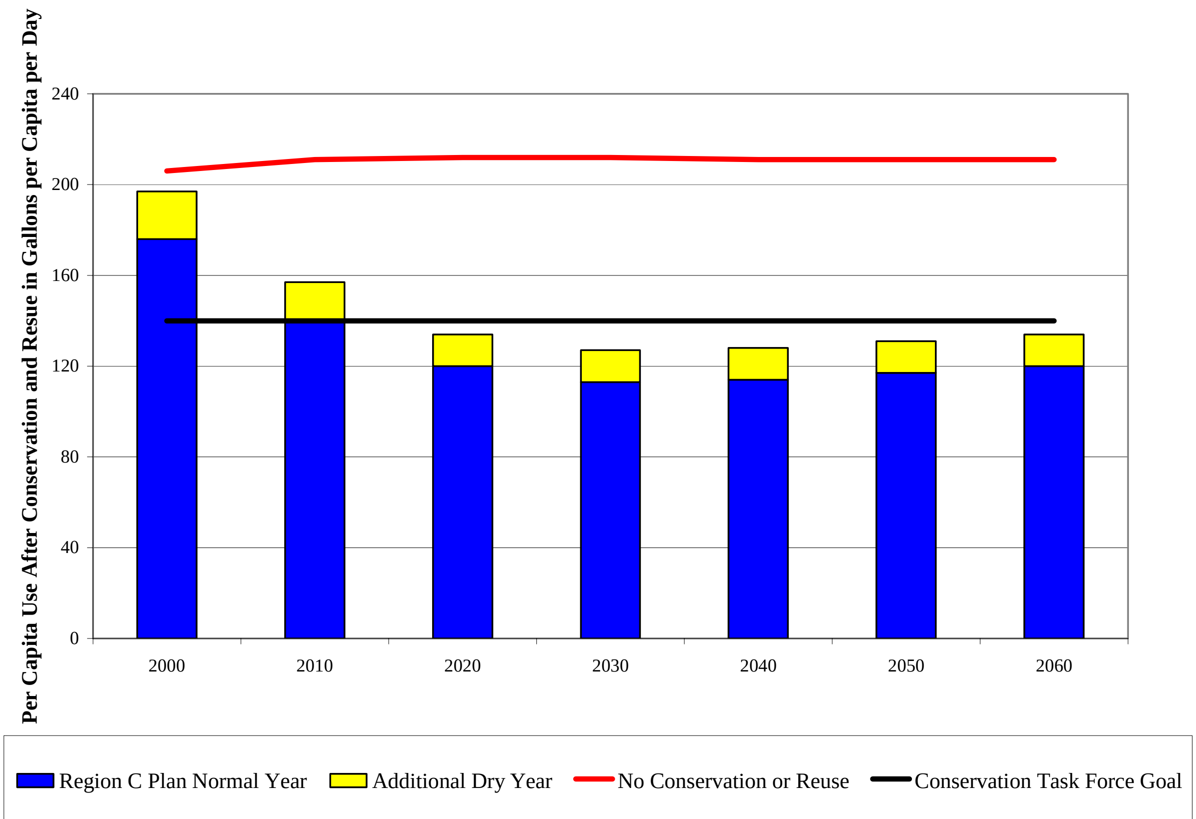
Water Conservation and Reuse

The Region C Water Planning Group considered 23 municipal water conservation strategies suggested as best management practices by the Conservation Implementation Task Force and selected 16 as potentially feasible for Region C. A detailed estimate of cost and savings for the 16 potentially feasible strategies resulted in a recommended water conservation program for Region C that accomplishes the following:

- Including the 242,000 acre-feet per year of conservation built into the demand projections (for low flow plumbing fixtures and efficient power plants), a total conservation and reuse of 1.3 million acre-feet per year by 2060, 37 percent of the region's demand without conservation.
- A reduction in dry-year per capita municipal use for the region (after crediting for reuse) from 197 gpcd in 2000 to less 140 gpcd by 2020.

Figure ES.4 shows the change in per capita use over time in Region C if the recommended water conservation and reuse measures in the plan are fully implemented. Chapter 6 includes a more detailed discussion of conservation and reuse for the region.

Figure ES.4
Projected Per Capita Municipal Use in Region C
with Full Implementation of Planned Conservation and Reuse



Recommended Water Management Strategies

Table ES.1 lists the major recommended water management strategies for Region C. (Major water management strategies are those supplying over 60,000 acre-feet per year or involving the construction of a reservoir.) Figure ES.5 shows the location of the proposed major water management strategies, which will provide 2.25 million acre-feet per year in new supplies for the region. In total, the Region C plan includes water management strategies to develop 2.7 million acre-feet per year of new supplies, for a total available supply of 4.1 million acre-feet per year in 2060. The supply is about 20 percent greater than the projected demand, leaving a reasonable reserve to provide for difficulties developing strategies in a timely manner, droughts worse than the drought of record, and greater than expected growth.

Figure ES.6 shows the comparison of supply and demand for Region C with the development of new supplies. Figure ES.7 shows the makeup of the 4.1 million acre-feet per year of supplies proposed for the region in 2060. One third of the supply is already available to the region from surface water and groundwater in 2005; one quarter is developed from conservation and reuse efforts, one-quarter is from the connection of existing supplies, and slightly less than one-fifth is from the development of new reservoirs. The plan includes only four major new reservoirs (compared to more than 25 developed to supply water for Region C over the last 55 years.)

Cost of the Proposed Plan

Most of the new supplies for Region C will be developed by the major wholesale water providers in the region. Table ES.2 shows the amount of new supply proposed for the five largest wholesale water providers in Region C and the cost to develop that supply. The total cost of implementing all of the water management strategies in the plan is $14 billion. The specific recommended water management strategies recommended for wholesale water providers and water user groups are discussed in sections 4D, 4E, and 4F of the report.

Table ES.1
Recommended Major Water Management Strategies

Strategy	Supplier	Supply (Acre-Feet per Year)	Supplier Capital Cost
Toledo Bend Reservoir	NTMWD	200,000	$886,002,000
	TRWD	200,000	$1,035,188,000
Marvin Nichols Reservoir	NTMWD	174,840	$534,125,000
	TRWD	280,000	$1,482,167,000
	UTRWD	35,000	$142,761,000
TRWD 3rd Pipeline & Reuse	TRWD	188,765	$626,347,000
Lower Bois d'Arc Ck. Res.	NTMWD	123,000	$399,190,000
Lake Fork Reservoir	DWU	120,000	$362,916,000
Oklahoma Water	NTMWD	50,000	$128,898,000
	TRWD	50,000	$287,349,000
	UTRWD	15,000	$60,967,000
Lake Palestine	DWU	111,460	$414,447,000
New Lake Texoma (Blend)	NTMWD	113,000	$201,829,000
Lake Fastrill	DWU	112,100	$569,170,000
Wright Patman Lake - Flood Pool	DWU	112,100	$572,036,000
East Fork Reuse Project	NTMWD	102,000	$288,879,000
Return Flows above DWU Lakes	DWU and UTRWD	79,605	$0
Southside (Lake Ray Hubbard) Reuse	DWU	67,253	$200,333,000
Lewisville Lake Reuse	DWU	67,253	$191,439,000
Lake Ralph Hall and Reuse	UTRWD	50,740	$211,153,000
Region C Total		**2,252,116**	**$8,595,196,000**

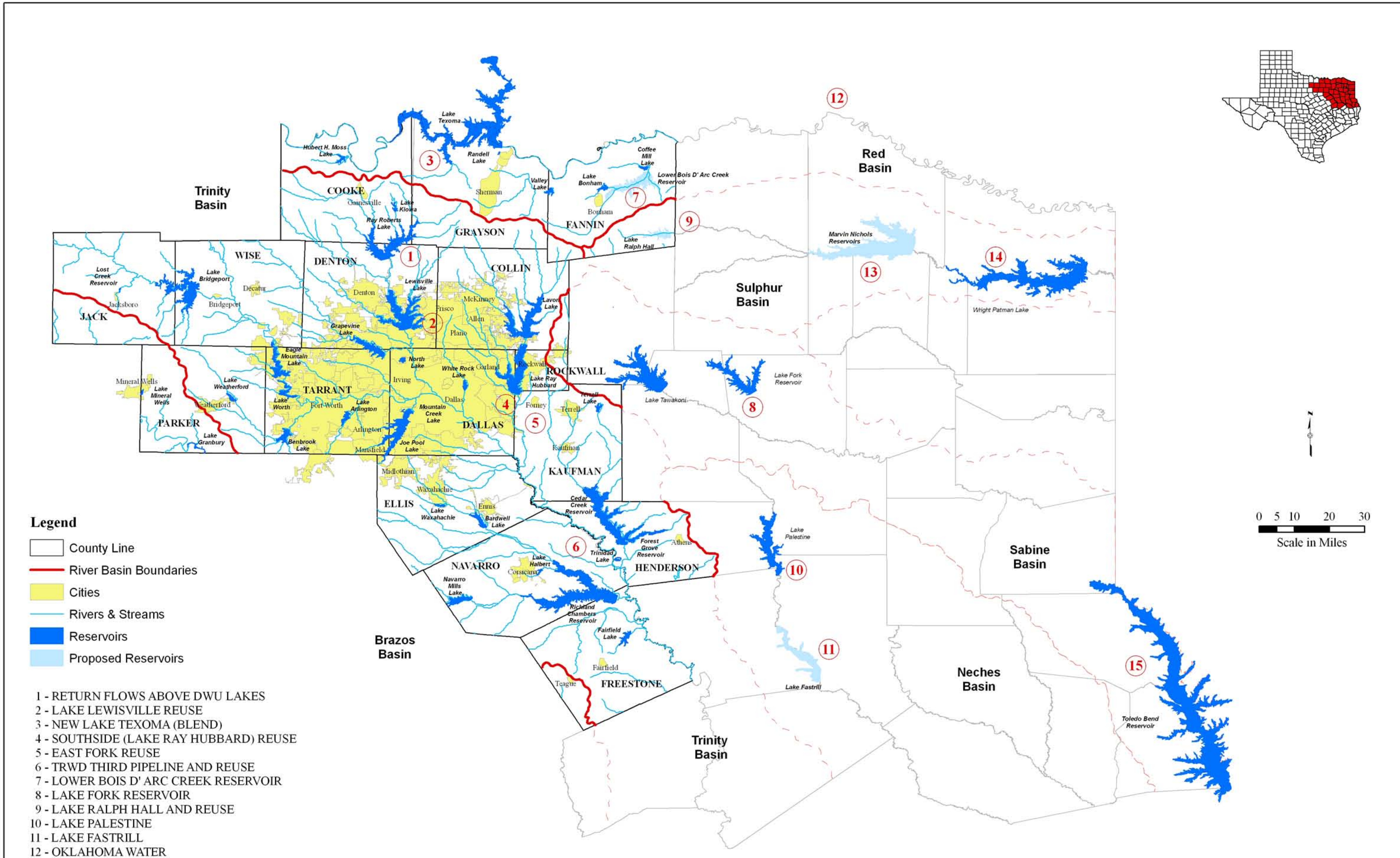


Figure ES.5
Recommended Major Water Management Strategies for Region C

Figure ES.6
Supply and Demand for Region C with the Development of New Supplies

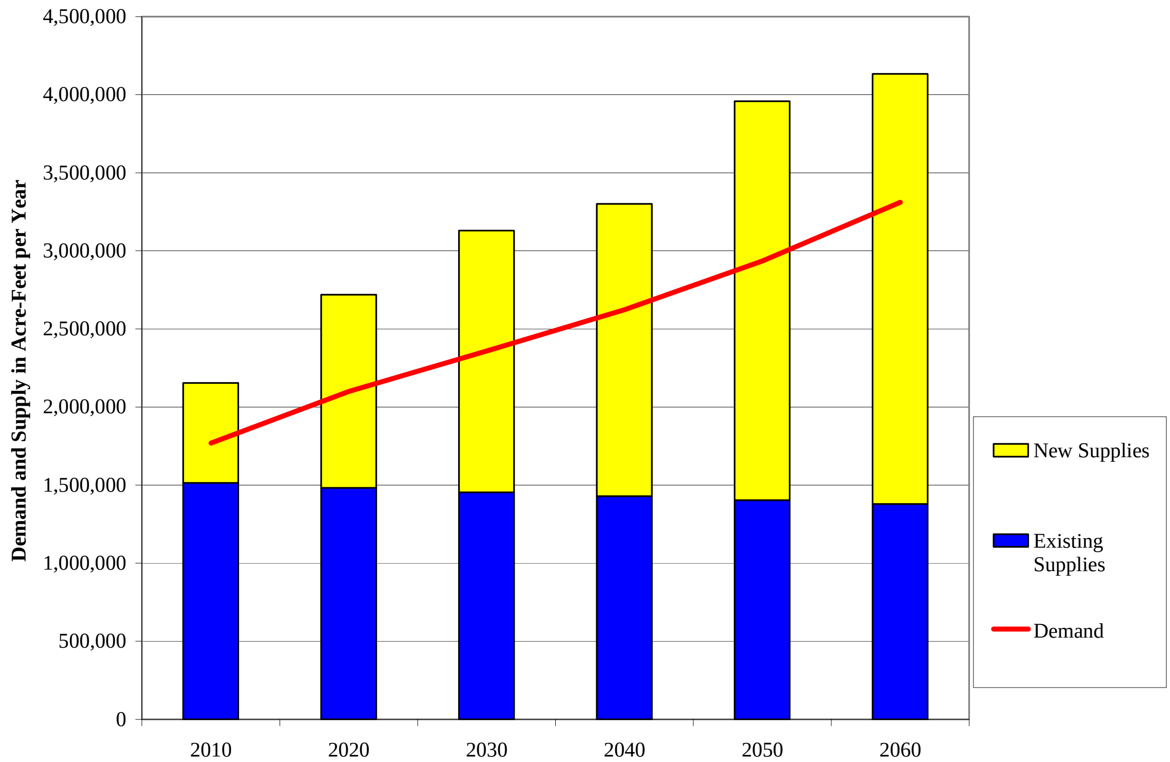


Figure ES.7
Sources of Water Available to Region C as of 2060

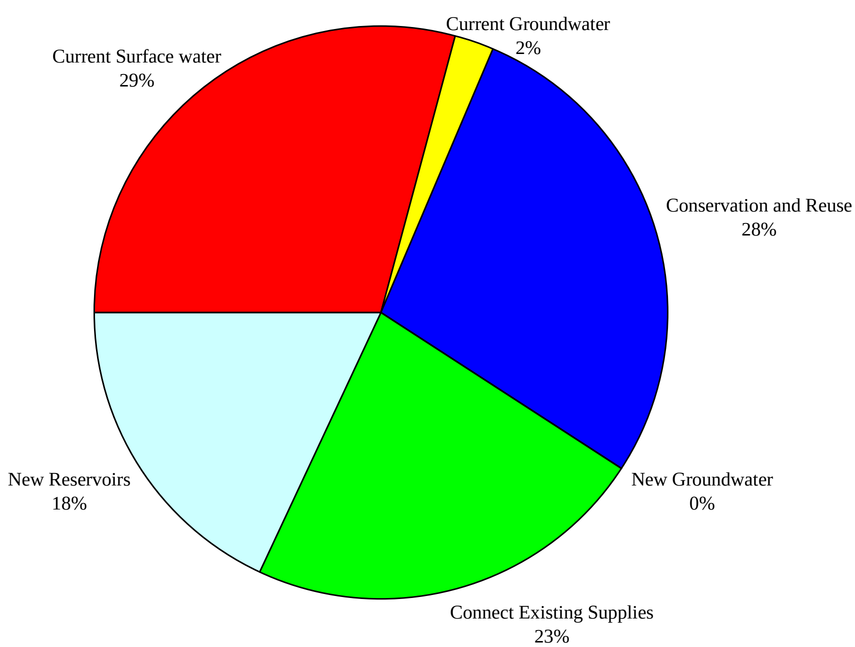


Table ES.2
2060 Supplies for the Largest Wholesale Water Providers in Region C

Wholesale Water Provider	2060 Supplies (Acre-Feet per Year)			% of Total Supply from Conservation and Reuse	Cost of Strategies (Millions)
	Currently Available	New Strategies	Total		
Dallas Water Utilities	422,647	758,328	1,180,975	26.2%	$2,811
Tarrant Regional Water District	394,049	698,558	1,092,607	24.6%	$3,562
North Texas Municipal Water District	254,020	792,355	1,046,375	25.7%	$3,848
City of Fort Worth	249,483	429,987	679,470	24.1%	$783
Trinity River Authority	96,060	225,076	321,136	59.1%	$340
Upper Trinity Regional Water District	41,265	155,413	196,678	27.2%	$858
Total					**$12,202**

Note: Supplies do not total because of overlaps. For example, Tarrant Region Water District supplies Fort Worth and the Trinity River Authority, Dallas Water Utilities supplies Upper Trinity Regional Water District, etc.

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Brazos G Regional Water Plan

Executive Summary

Background

Since 1957, the Texas Water Development Board (TWDB) has been charged with preparing a comprehensive and flexible long-term plan for the development, conservation, and management of the state's water resources. The current state water plan, *Water for Texas, January 2002*, was produced by the TWDB and based on approved regional water plans pursuant to requirements of Senate Bill 1 (SB1), enacted in 1997 by the 75th Legislature. As stated in SB1, the purpose of the regional water planning effort is to:

> "Provide for the orderly development, management, and conservation of water resources and preparation for and response to drought conditions in order that sufficient water will be available at a reasonable cost to ensure public health, safety, and welfare; further economic development; and protect the agricultural and natural resources of that particular region."

SB1 also provides that future regulatory and financing decisions of the Texas Commission on Environmental Quality (TCEQ) and the TWDB be consistent with approved regional plans.

The TWDB is the state agency designated to coordinate the overall statewide planning effort. The Brazos G Area, which is comprised of all or portions of 37 counties (Figure ES-1), is one of the State's 16 planning regions established by the TWDB. The TWDB appointed members to the regional planning groups, who serve without pay. The Brazos G Regional Water Planning Group (BGRWPG) was originally appointed by the TWDB to represent a wide range of stakeholder interests and act as the steering and decision-making body of the regional planning effort. As member terms expire, new members are appointed by the BGRWPG itself through solicitation of nominations. The BGRWPG adopted bylaws to govern its operations and, in accordance with its bylaws, designated the Brazos River Authority (BRA) as the administrative agency and principal contractor to receive a grant from the TWDB to develop the water plan. Ms. Teresa Clark serves as the Regional Planning Project Manager for the BRA, assisted by Julie Andress. The BGRWPG selected HDR Engineering, Inc. as prime consultant for the planning and engineering tasks necessary for plan development.

The BGRWPG consists of 19 voting members who represent the following 12 interests: the public, counties, municipalities, industries, agriculture, the environment, small businesses, electric-generating utilities, river authorities, water districts, water utilities and groundwater conservation districts. The BGRWPG also includes several non-voting members who participate in the deliberations of the BGRWPG, and contribute excellent knowledge and insight to the group. Table ES-1 lists the voting and non-voting members and interest groups represented on the BGRWPG who contributed to the development of the 2006 Brazos G Regional Water Plan (both current and recently retired).

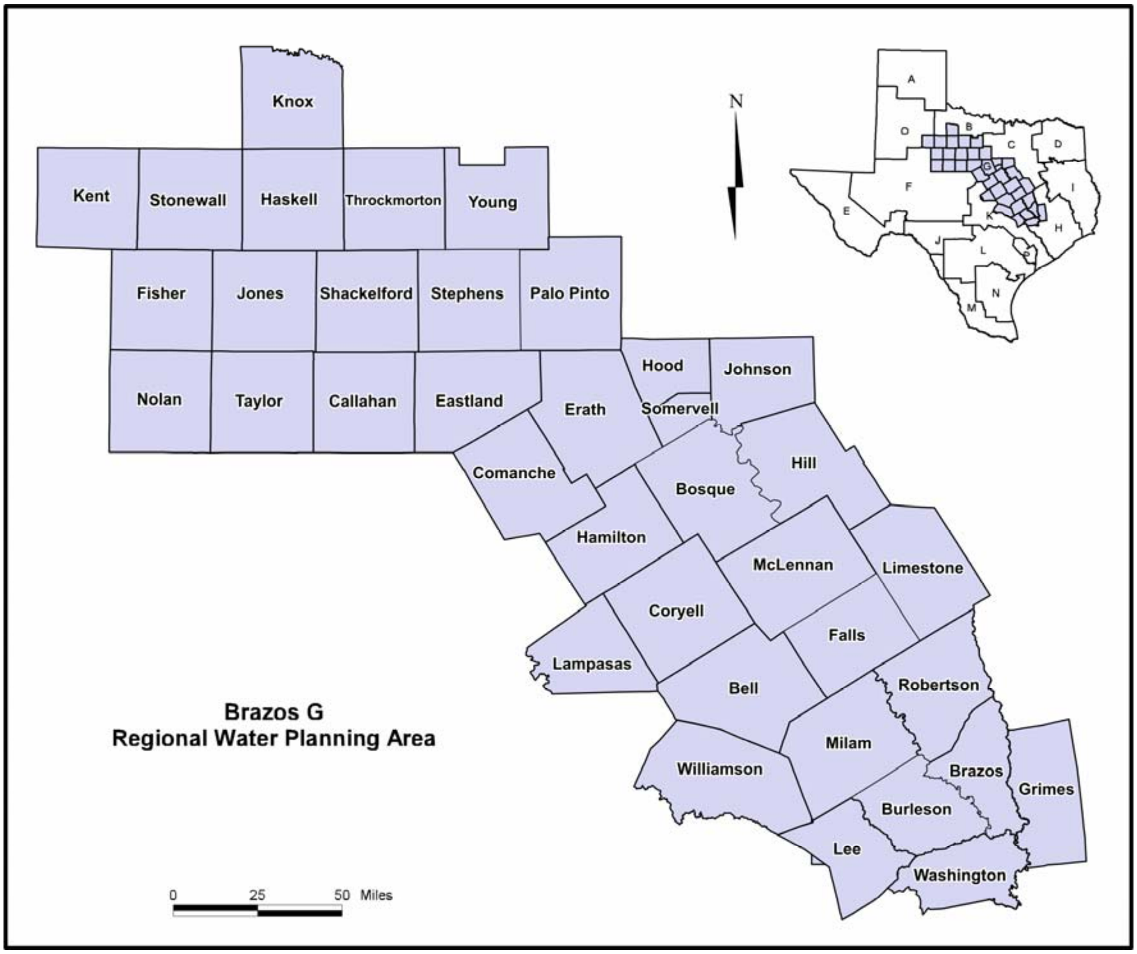

Figure ES-1. Brazos G Regional Water Planning Area

The planning horizon to be used is the 60-year period from 2000 to 2060. This planning period allows for long-term forecast of the prospective water situation, sufficiently in advance of needs, to allow for appropriate management measures to be implemented. As required in Senate Bill 1, the TWDB specified planning rules and guidelines (31 TAC 357.7 and 357.12) to focus the efforts and to provide for general consistency among the regions so that the regional plans can then be aggregated into an overall State Water Plan.

Table ES-1.
Current and Recent Brazos G RWPG Voting Members
(as of June 2005)

Interest Group	***Name***	***Entity***
Voting Members		
Agricultural	Dale Spurgin (6/04 to present)	Judge, Jones County
	Wayne Wilson (12/04 to present)	Rancher
	Steve Sanford (resigned 11/03)	Farmer/Rancher
	Chaunce Thompson (retired 12/04)	Cattlemen
Counties	Judge Tim Fambrough	Nolan County
	Judge Jon Burrows	Bell County
	Judge Mike Sutherland (12/04 to present)	Burleson County
	Tony Jones (retired 12/04)	Brazos County Commissioners Court
	Judge David Purdue (resigned 3/02)	Knox County
Electric Generating Utilities	Scott Diermann	TXU Electric
	Ken Smith (resigned 11/02)	TXU Electric
Environmental	Stephen L. Stark	Texas A&M University
Industry	Randy Waclawczyk (12/04 to present)	Alcoa
	Mark Bryson (retired 12/04)	Alcoa
Municipalities	Mike Morrison (Chairman)	City of Abilene
	Wiley Stem III	City of Waco
	Tom Clark	City of Round Rock
	Alva D. Cox (12/04 to present)	City of Granbury
	Truman O. Blum (retired 12/04)	Former mayor, City of Clifton
	James Nuse (retired 11/03)	City of Round Rock
Public	Scott Mack, DDS	Dentist
River Authorities	Phil Ford	Brazos River Authority
Small Business	Horace R. Grace	AMG Enterprises, Inc.
Water Districts	Terry Kelley	Johnson County SUD
	Kathleen Webster (12/04 to present)	West Central Texas MWD
	A.V. Jones, Jr. (retired 12/04)	West Central Texas MWD
Groundwater Districts	Mike McGuire (12/04 to present)	Rolling Plains GCD
Water Utilities	Kent Watson	Wickson Creek Special Utility District
Non-Voting Members		
Region H RWPG Liaison	John Baker	Brazos River Authority
LCRA Representative	James Clarno	Lower Colorado River Authority
Region F RWPG Liaison & CRMWD Representative	John Grant	Chair, Region F & GM of Colorado River Municipal Water District
Llano Estacado (O) RWPG Liaison	Terry Lopas	Brazos River Authority
Lower Colorado (K) RWPG Liaison	Mark Jordan	Lower Colorado River Authority
TWDB Project Manager	David Meesey	Texas Water Development Board
TPWD	Mellisa Mullins	Texas Parks and Wildlife Department
TDA	E.W. Wesley	Texas Department of Agriculture
Region C RWPG Liaison	Paul Zweiacker	Texas Utilities

Pursuant to Regional and State Water Planning Guidelines (Texas Administrative Code, Title 31, Part 10, Chapters 357 and 358), the BGRWPG developed the 2001 Brazos G Regional Water Plan, which was then integrated into the State Water Plan "Water for Texas – 2002" by the TWDB. The 2006 Brazos G Regional Water Plan, of which this Executive Summary is a part, represents the first update of the regional water plan as presently required to occur on a 5-year cycle. The TWDB will integrate this Regional Water Plan into a State Water Plan to be issued in 2007.

The structure of the 2006 Regional Water Plan is organized in accordance with TWDB guidelines and summarized by section title as follows.

1) Description of the Brazos G Region (Volume I)
2) Projected Population and Water Demands (Volume I)
3) Evaluation of Water Supplies in the Region (Volume I)
4) Identification, Evaluation and Selection of Water Management Strategies Based on Needs
   - 4A) Comparison of Demand to Supply (Volume I)
   - 4B.1) Identification, Evaluation and Selection of Water Management Strategies (Volumes I and II)
   - 4B.2) Technical Evaluations of Water Management Strategies (Volume II)
   - 4C) Water Supply Plans (Volume I)
5) Impacts of Recommended Water Management Strategies on Key Parameters of Water Quality and Moving Water from Rural and Agricultural Areas (Volume I)
6) Water Conservation and Drought Management Recommendations (Volume I)
7) Consistency with Long-Term Protection of the State's Water, Agricultural, and Natural Resources (Volume I)
8) Recommendations for Unique Stream Segments, Unique Reservoir Sites and Other Legislative Recommendations (Volume I)
9) Report to the Legislature on Water Infrastructure Funding Recommendations (Volume I)
10) Adoption of Plan (Volume I)

Description of the Region

The Brazos G Region can be described by a single word—**diverse**. From the piney woods of Brazos and Grimes Counties to the rolling plains of Nolan County; from sparsely populated Stonewall County to Williamson County, often listed as the fastest growing county in the nation; from the prodigious Carrizo-Wilcox Aquifer in the southeast to the meager dribbles from windmills in Shackelford County; from 44 inches of annual rainfall in the east to 24 inches annually in the west (in a good year); from the Chisholm Trail through Stephens County to the NAFTA trail known as Interstate Highway (IH) 35; these diverse characteristics make for a wide variation in water supplies, demands, and availability of affordable options to meet needs.

Population and Water Demand Projections

In December 2002, the TWDB published population and water demand projections for each county in the state. In the Brazos G Area, population projections were developed for 184 municipal water user groups, which are defined as cities with a population greater than 500 in 2000, and water supply corporations and utilities using water volumes of 280 acft or more in 2000. To account for people living outside the cities, projections were also developed for a 'county-other' category of municipal water use for each of the 37 counties in the region. Requests for revisions to the population and municipal water demand projections were forwarded to the TWDB and in many cases were adopted.

Water Demand Projections

Figure ES-2 illustrates population growth in the entire Brazos G Regional Water Planning Area (BGRWPA) for 1900 to 2000 and projected growth for 2010 to 2060.

Population trends may be further understood by dividing the planning region into three subregions: the northwestern Rolling Plains, the central IH-35 Corridor, and the southeastern Lower Basin. Figure ES-3 illustrates historical population growth in the three sub-regions from 1900 to 2000 and projected growth from 2010 to 2060. Projected growth is greatest in the IH-35 Corridor.

Water Demand Projections

Water demand projections have been compiled for six categories of water use: (1) Municipal, (2) Manufacturing, (3) Steam-Electric Cooling, (4) Mining, (5) Irrigation, and (6) Livestock. Each of the non-municipal uses is aggregated on a county basis, and is defined as a separate water user group (WUG) within each county. The TWDB has developed water demand projections for each of the five non-municipal WUGs in each of the 37 counties in Region G.

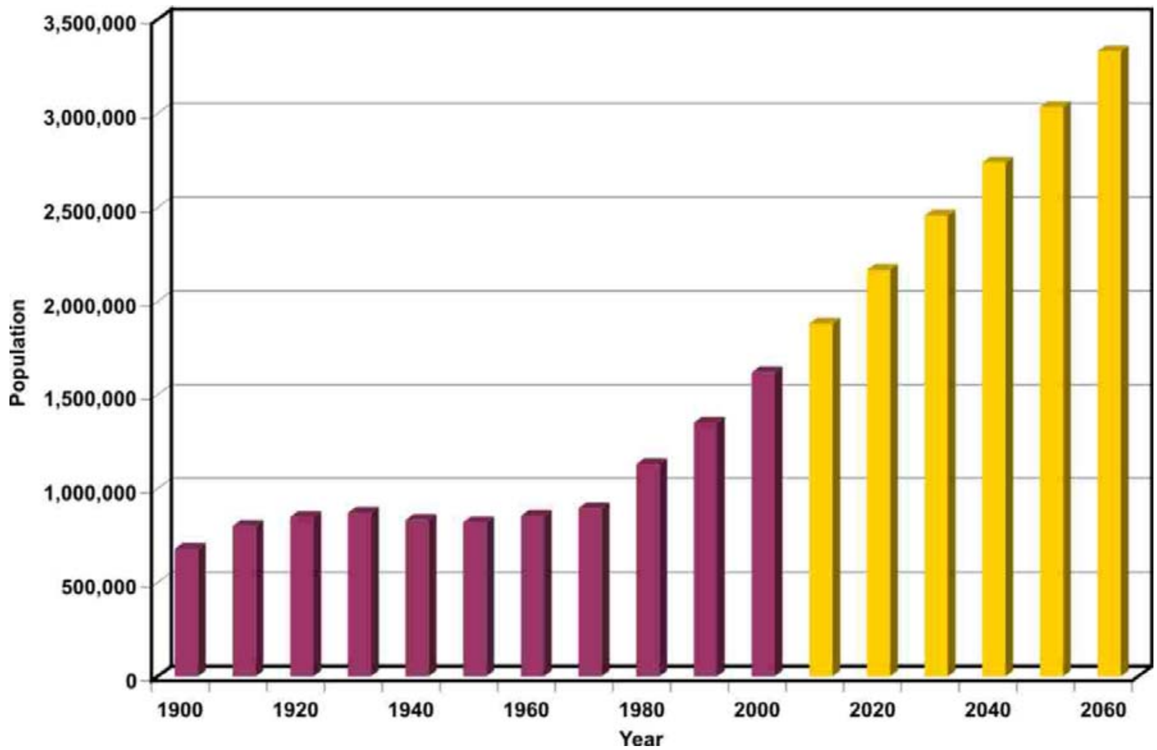

Figure ES-2. Historical and Projected BGRWPA Population

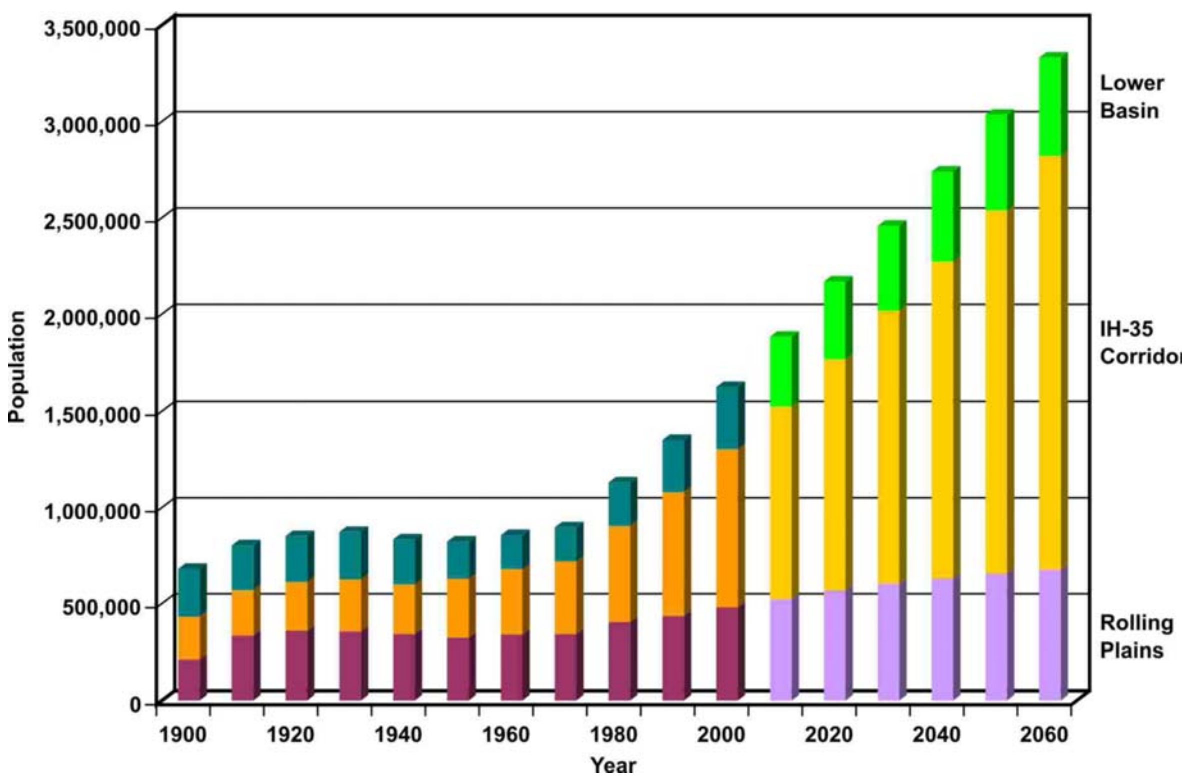

Figure ES-3. Historical and Projected Population by Sub-Region

Total water use for the region is projected to increase from 795,183 acft in 2000 to 1,150,973 acft in 2060, a 45 percent increase, as shown in Figure ES-4. The six types of water use as percentages of total water use are shown for 2000 and 2060 in Figure ES-5. Municipal, manufacturing, and steam-electric water use as percentages of the total water use are projected to increase from 2000 to 2060, while mining, irrigation, and livestock water use are projected to decrease as percentages of the total.

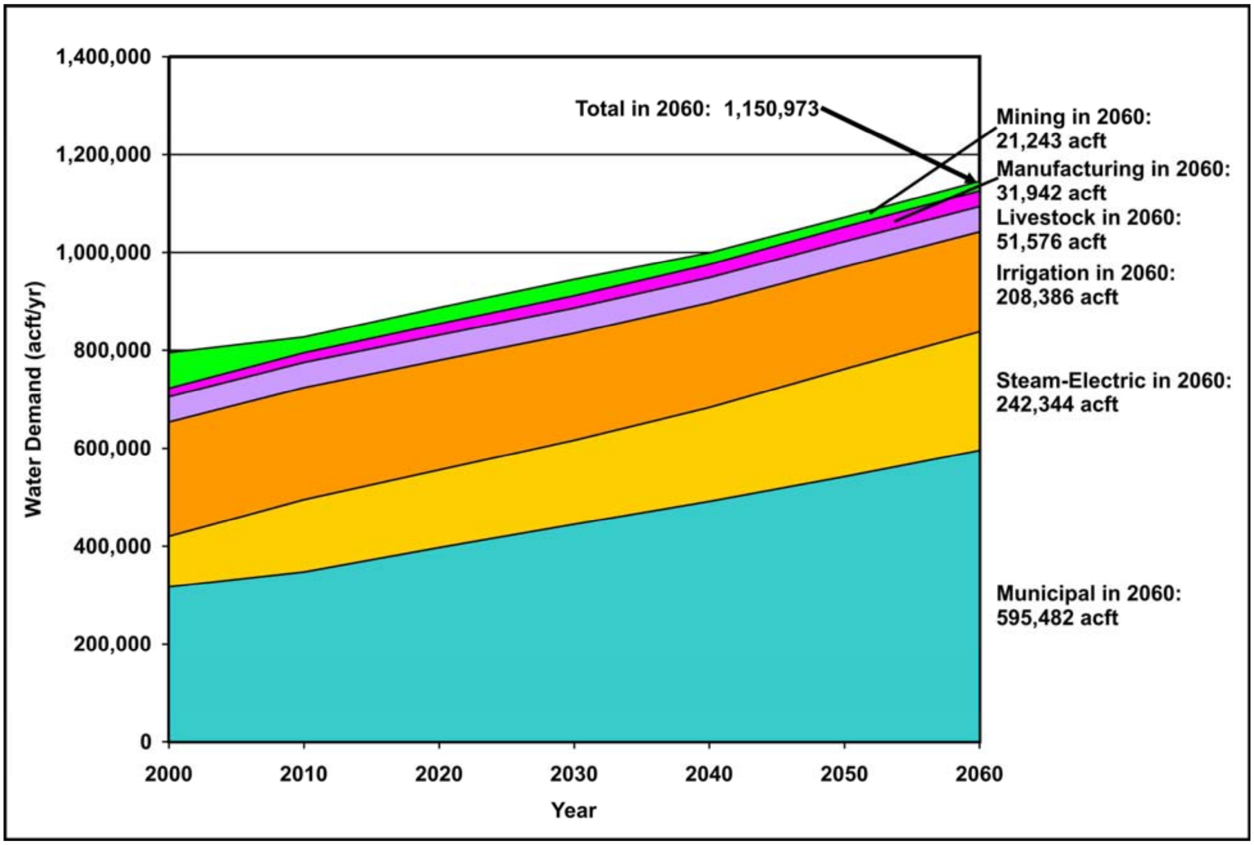

Figure ES-4. Projected Total Water Demand

Water Supply

Surface Water Supplies

Streamflow in the Brazos River and its tributaries, along with reservoirs in the Brazos River Basin, comprise a vast supply of surface water in the Brazos G Area. Diversions and use of this surface water occurs throughout the entire region with over 1,000 water rights currently issued. However, the supply of surface water varies greatly through the region due to the large variation in rainfall and a correspondingly large variation in evaporation rates. The

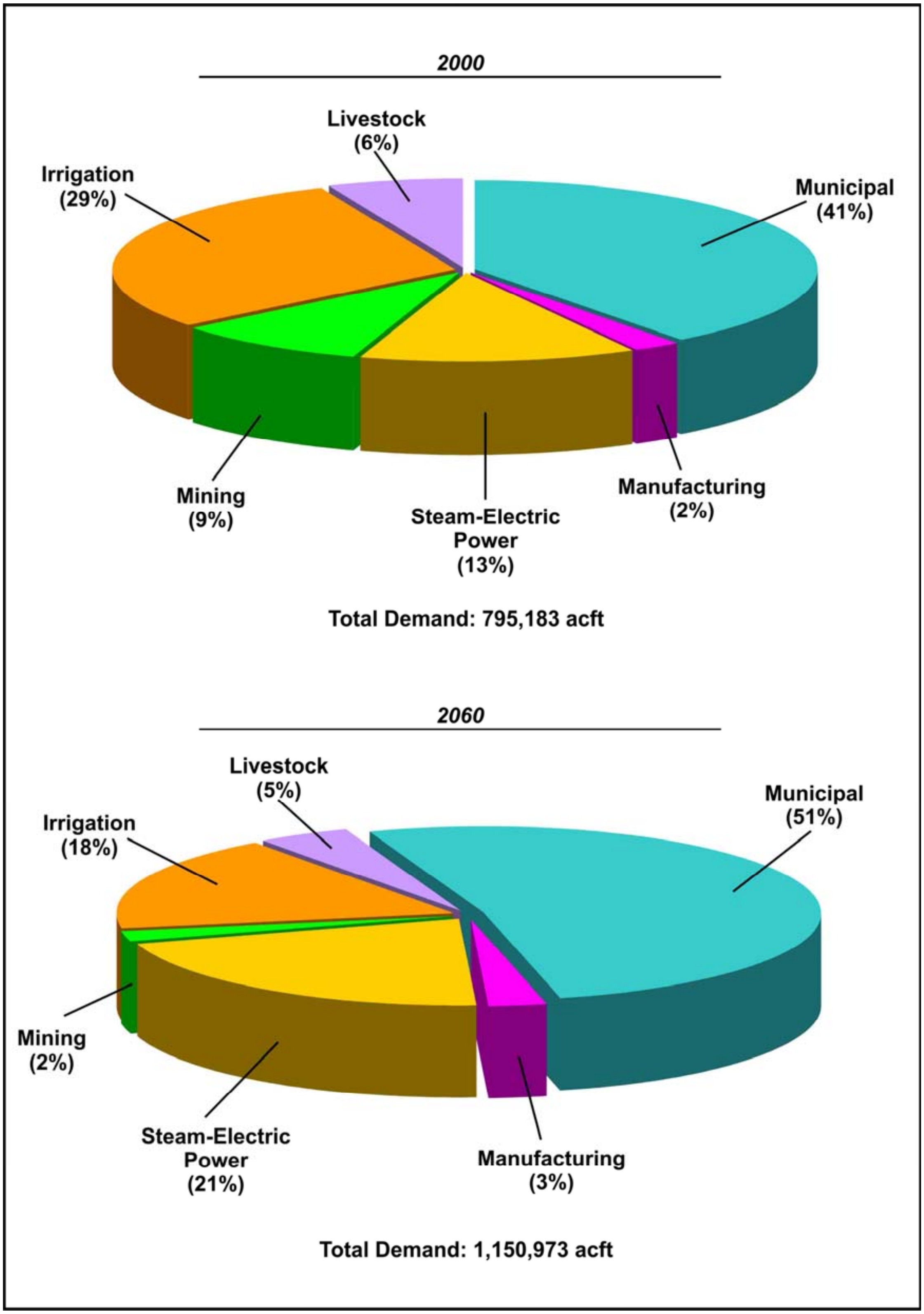

Figure ES-5. Total Water Demand

principal tributaries to the Brazos River in the planning area are the Clear Fork, the Double Mountain Fork, the Salt Fork, Bosque River, Little River, Navasota River, Little Brazos River and Yegua Creek. Major water supply reservoirs are owned by the BRA (three in the planning region), U.S. Army Corps of Engineers (nine in the region), West Central Texas MWD, the City of Abilene, and Texas Utilities. The western part of the region is heavily dependent on surface water sources, partly due to the absence of large quantities of potable-quality groundwater.

The State of Texas owns the surface water resources of the State, and issues water rights to utilize surface water. A total of 1,123 water rights currently exist in the Brazos River Basin, with a total authorized diversion of 2,664,000 acft/yr, of which 1,412,102 are located in the BGRWPA. Those rights located in the BGRWPA contribute a total firm supply of 695,479 acft/yr through a repeat of the drought of record. This supply number is less than total surface water availability in the region of 866,372 acft/yr, because supply to irrigation was calculated on a 75 percent available, 75 percent of the time basis, which increases the estimated supply available for irrigation by assuming that irrigation does not require a firm supply year in and year out. It is important to note that a small percentage of the water rights make up a large percentage of the authorized diversion volume. In the Brazos River Basin, 39 water rights (3.4 percent) make up 2,372,000 acft/yr (89 percent) of the authorized diversion volume. The remaining 1,084 water rights primarily consist of small irrigation rights distributed throughout the river basin. Figure ES-6 shows a comparison of significant water rights in the Brazos River Basin by number of rights and diversion volume.

Groundwater Supplies

Fifteen aquifers underlie parts of the Brazos G Area and, if developed fully, can provide a combined reliable supply of about 533,520 acft/yr. As currently developed, a total groundwater supply of 318,630 acft/yr exists in the region. The Seymour Aquifer supplies significant quantities of water in the western part of the region. Other aquifers that are depended on in the western part of the region are the Dockum and the Edwards-Trinity. The Trinity and Edwards-BFZ (Northern Segment) are heavily relied upon in the IH-35 corridor and to the west. Both of these aquifers are being pumped in excess of their estimated sustainable yield in some counties. In the eastern part of the region, the Carrizo-Wilcox is a prolific water supply with lesser amounts pumped from the Queen City, Sparta, and Brazos River Alluvium.

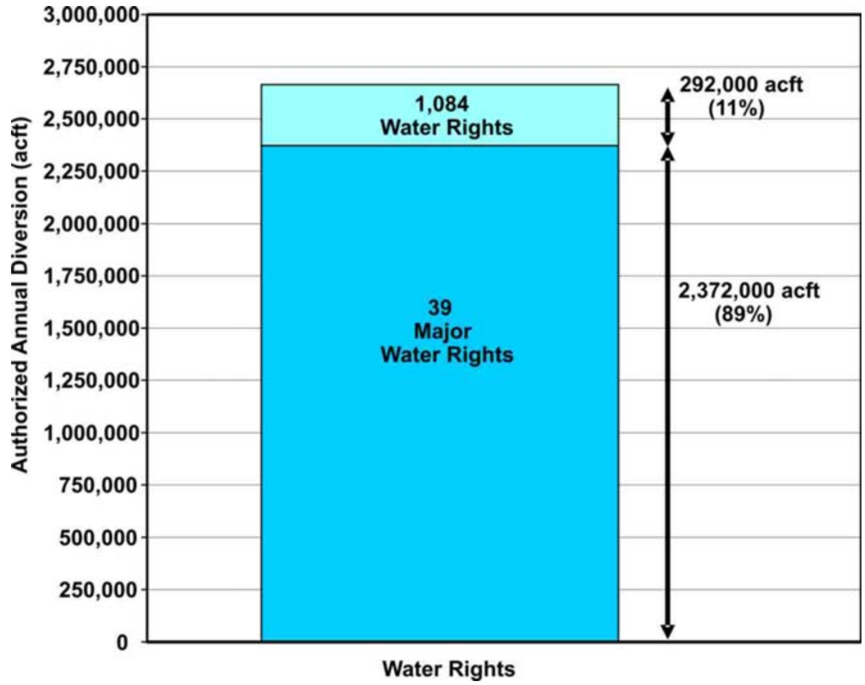

Figure ES-6. Comparison of Water Rights in the Brazos River Basin

Water Quality

Natural salt pollution has been recognized as a serious and widespread water quality problem in the Brazos River Basin. No other pollution source, man-made or natural, has had the impact of the natural salt sources located in the upper basin. Due to these water quality issues, some sources of water—particularly from Lake Whitney, Lake Granbury, and Possum Kingdom Reservoir—may limit their suitability for some uses and require higher cost, advanced treatment (desalination). As the Brazos River flows to the Gulf, inflows from tributaries decrease the concentration of dissolved minerals, which in turn improves the quality of water.

Supply and Demand Comparison

A comparison of total supplies available in the region (developed groundwater supplies and firm surface water) with demand for all use categories in the region shows a surplus past the year 2050. These mask shortages that are projected to occur to individual water supply entities and water user groups. Figure ES-7 illustrates this issue by summarizing demands and supplies for the Brazos G Area, and for Williamson County. Shortages are projected for Williamson County starting at about the year 2030, while overall regional supplies are projected to exceed regional demands until past the year 2050. Even within most counties that have projected overall surpluses, there are individual entities that do not have sufficient supply to meet projected needs. Only five of the 37 counties in the Brazos G Area have no projected shortages for all water user groups: Comanche, Hamilton, Jones, Stonewall, and Young.

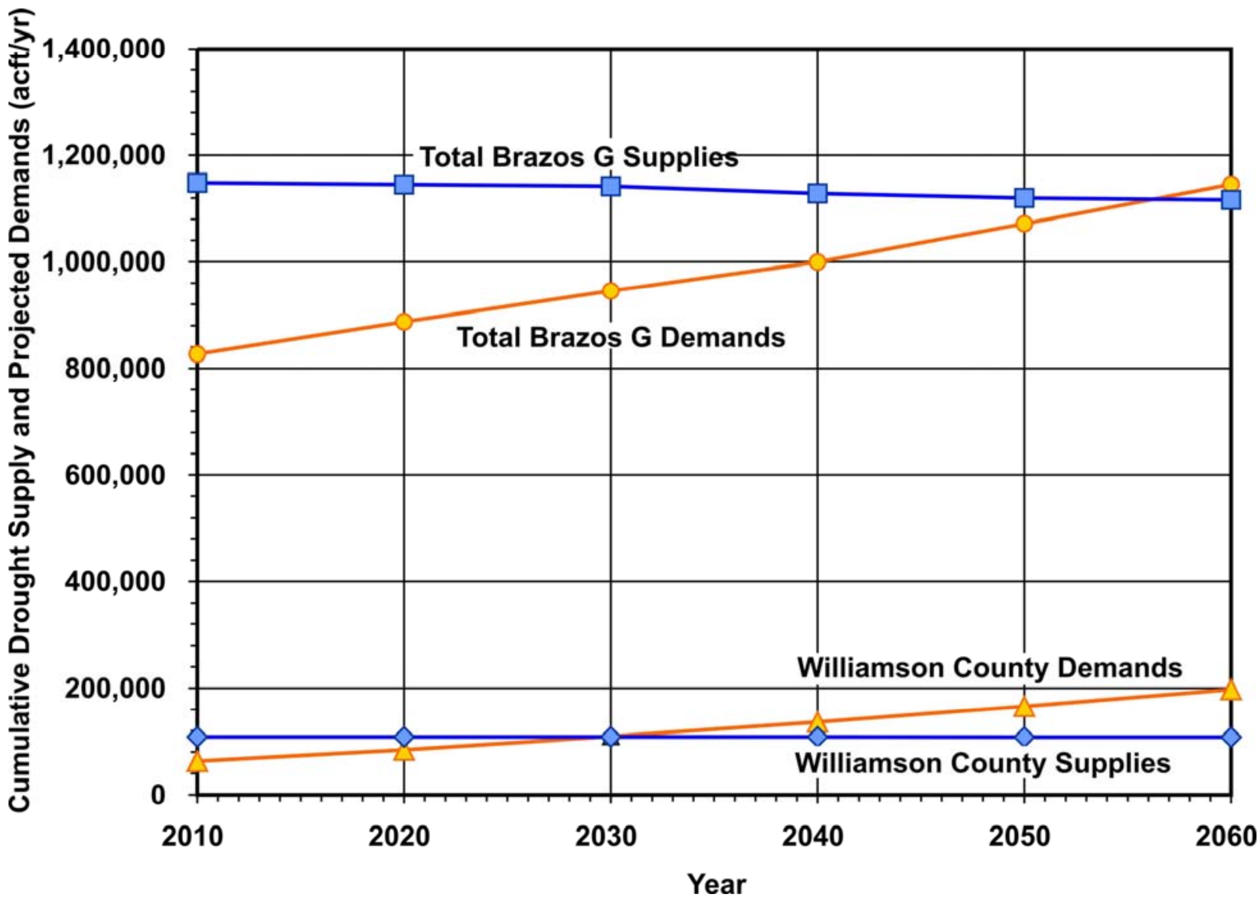

Figure ES-7. Comparison of Supplies and Demands for Brazos G Region and Williamson County

Water Supply Strategies to Meet Needs

The water management strategies in Table ES-2 were identified by the BGRWPG as potentially feasible to meet shortages. These strategies were evaluated by the consultant team and compared to criteria adopted by the BGRWPG. Section 4B in Volume 2 contains subsections discussing each of these possible strategies.

Table ES-2.
Water Management Strategies Identified as Potentially Feasible to Meet Shortages

Water Management Strategies	
Report Section (Volume II)	**Water Management Strategy and Description**
4B.2	**Advanced Water Conservation** (implement accelerated use of various water conservation techniques to achieve water savings above what is already included in the TWDB water demand projections)
4B.3	**Wastewater Reuse** (use highly treated wastewater treatment plant effluent to meet non-potable water needs, including landscape irrigation and industrial use)
4B.4	**System Operation of Brazos River Authority Reservoirs** (coordinated operation of the BRA reservoir system will increase supplies, maximize use of existing facilities and delay the need for new reservoir construction)
4B.5	**Groundwater/Surface Water Conjunctive Use (Lake Granger Augmentation)** (utilize groundwater to firm up interruptible (non-firm) supplies greater than the firm yield of the reservoir)
4B.6	**Desalination** (treatment of brackish water to remove minerals with resulting potable water) • Lake Granbury supplies to Johnson County • Brackish groundwater to N.E. Johnson County
4B.7	**Millers Creek Reservoir Augmentation** (supplement yield of a reservoir by diverting flows from an adjacent stream into the reservoir)
4B.8	**Aquifer Storage and Recovery** (Inject or percolate excess surface water into groundwater aquifers, storing for future use) • Seymour Aquifer • Trinity Aquifer (Johnson County)
4B.9	**Brush Control and Range Management** (increase deep percolation and discharge to streams by removing unwanted brush)
4B.10	**Weather Modification** (cloud seeding to increase precipitation frequency and intensity)
4B.11	**Interregional Water Management Strategies** (provide water supplies into the Brazos G Region from adjacent regions) • TRA Reuse through Joe Pool Reservoir (Region C) • Regional Surface Water Supply to Williamson County from Lake Travis (Region K)
4B.12	**New Reservoirs** (new or updated evaluations of the following proposed new reservoirs) • Breckenridge Reservoir (Cedar Ridge Site) • South Bend Reservoir • Throckmorton Reservoir • Double Mountain Fork Reservoir (Sites No. 1 & 2) • Turkey Peak Reservoir • Millican Reservoir
4B.13	**Off-Channel Reservoirs** (construction of smaller reservoirs on tributary streams with lower environmental impact, lower cost dam, and usually with pump-over of supplies from a larger stream). Possible projects include: • Wheeler Branch Off-Channel Reservoir • City of Groesbeck Off-Channel Reservoir • Peach Creek Lake • Little River Off-Channel Reservoir • Lake Palo Pinto Off-Channel Reservoir
4B.14	**Interconnection of Regional and Community Systems** (use larger cities' systems or other facilities more fully and assist smaller communities to meet their needs). Possible projects include: • Bosque County Regional Project • Midway Pipeline Project (West Central Brazos Distribution System) • Interconnection from Abilene to Sweetwater • Interconnection of City of Waco System with Neighboring Communities • Interconnection of Central Texas WSC with Salado WSC
4B.15	**Carrizo-Wilcox Aquifer Development** (further develop and utilize the Carrizo-Wilcox Aquifer) • Additional Development of Carrizo-Wilcox Aquifer for Brazos County Needs • Carrizo-Wilcox Water Supply for Williamson County • Lake Granger Augmentation (Section 4B.5)
4B.16	**Voluntary Redistribution** (the purchase or lease of water supply from an entity that has water supply in excess of long-term or interim needs)

Water Plan Findings

Table ES-3 summarizes the recommended water management strategies in the plan that develop or import new sources of supply into the Brazos G Area. Strategies that utilize existing water resources without increasing or augmenting those supplies are not listed.

Total new supplies of water into the Brazos G Area total 590,231 acft/yr, comprised of newly developed groundwater, supply transferred from other regions, newly developed surface water supplies, or supplies made available through conservation or augmentation of existing facilities. These totals do not reflect water trades between users of existing supplies in Region G, but represent entirely new supplies to the Brazos G Area. Total project costs for these new supplies exceed $1 billion.

The 2006 Brazos G Regional Water Plan includes recommendations for 21,393 acft/yr of municipal conservation savings and another 43,377 acft/yr for wastewater reuse. The conservation savings are on top of those already included in the TWDB demand projections, and the recommended reuse strategies are in excess of existing reuse supplies in the basin.

System operation of the Brazos River Authority's reservoirs can increase supplies in the Brazos G Area by more than 265,000 acft/yr (assuming interruptible supplies can be firmed up through conjunctive operation with other sources), with additional supplies available to the Region H Area in the lower basin. This strategy would more efficiently utilize the existing resources of the Brazos River Authority by expanding the supply that can be developed from the BRA's existing reservoirs, thus delaying the need for new reservoirs to meet growing needs in the basin. As shown by analysis of the Lake Granger Augmentation strategy, the interruptible supply proposed by the BRA can be firmed up with groundwater resources, further extending existing resources in the basin.

The West Central Brazos System Optimization Plan proposed by the City of Abilene and the West Central Texas Municipal Water District (WCTMWD) is an example of regional cooperation between the City of Abilene, the WCTMWD and the Brazos River Authority to ensure adequate supplies in the arid western portion of the Brazos G Area. Through a mix of existing supplies, new supplies and priority calls agreements with the BRA, the plan would develop an additional firm supply of almost 60,000 acft/yr. This system plan will provide the Abilene area with supplies that will insure against future droughts worse than the current drought of record.

Implementation of the 2006 Brazos G Regional Water Plan will result in the development of new water supplies that will be reliable in the event of a repeat of the most severe drought on record. It is evident that implementation of all recommended water management strategies is not likely to be necessary in order to meet projected needs within the planning period. The BGRWPG explicitly recognizes the difference between additional supplies and projected needs as System Management Supplies and has recommended the associated water management strategies in the Regional Water Plan for the following reasons:

- So that water management strategies are identified to replace any planned strategies that may fail to develop, through legal, economic or other reasons;
- To serve as additional supplies in the event that rules, regulations, or other restrictions limit use of any planned strategies;
- To facilitate development of specific projects being pursued by local entities for reasons that may not be captured in the supply and demand projections used to identify future supply shortages; and/or
- To ensure adequate supplies in the event of a drought more severe than that which occurred historically.

Other Aspects of the 2006 Brazos G Regional Water Plan

In addition to providing a roadmap for development of supplies to meet future water needs in the basin, the 2006 Brazos G Regional Water Plan includes other elements of value and interest to water supply managers and others in the Brazos G Area.

- The plan provides a concise summary of physiographic, hydrologic and natural resources in the Brazos G Area,
- The plan provides a comprehensive understanding of how water supplies have been developed and are managed in the region,
- The plan provides examples of drought management and water conservation plans that may assist water managers with developing plans for their systems, and
- The plan includes recommendations to the TWDB and the Texas Legislature regarding key water policy issues and the direction of water supply management in Texas.

Table ES-3. Summary of Recommended Water Management Strategies Involving New Sources of Supply in the 2006 Brazos G Regional Water Plan

Strategy	WUG or WWP	New Supply by 2060 (acft/yr)	Total Project Cost (2nd Quarter 2002 Prices)
Conservation Strategies			
Municipal	38 WUGs	21,393	N/D[1]
Manufacturing	18 Counties	1,430	N/D
Steam-Electric	9 Counties	13,281	N/D
Mining	10 Counties	1,074	N/D
Irrigation	6 Counties	8,027	N/D
Total Conservation		**45,205**	**N/D**
Reuse Strategies			
Reuse	Steam-Electric – Nolan County	560	$2,115,000
	City of Round Rock	7,443	$6,369,000
	City of Bryan	605	$6,485,000
	City of College Station	137	$2,358,000
	City of Cleburne	2,853	$1,048,000
	Steam-Electric – McLennan County (City of Waco)	16,000	$2,995,000
	City of Waco	15,779	N/D
Total Reuse		**43,377**	**$27,855,000**
Water Supply from other Regions			
LCRA/BRA Alliance	Chisolm Trail SUD	3,472	$18,518,000
	City of Round Rock	20,928	$101,336,000
LCRA Highland Lakes	Cedar Park	25,000	$81,748,000
TRA Reuse through Joe Pool Reservoir	Johnson County SUD	20,000	$79,257,000
Total from Other Regions		**69,400**	**$280,859,000**
Augmentation of Existing Surface Water Supplies			
Lake Palo Pinto Off-Channel Reservoir	Palo Pinto County MWD No. 1	3,110	$19,314,000
Millers Creek Reservoir Augmentation	North Central Texas Municipal Water District	4,870	$18,222,000
Raise Level of Gibbons Creek Reservoir	Steam-Electric – Grimes County	3,870	$8,003,000
BRA System Operation (Lake Granger Augmentation)	Chisholm Trail SUD	26,127[2]	$303,288,000
	City of Georgetown		
	Jarrell-Schwertner WSC		
	City of Round Rock		
	Williamson County – Other		
	Manufacturing – Williamson County		
Total Augmentation of Existing Surface Water Supplies		**37,977**	**$348,827,000**

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Table ES-3.
Summary of Recommended Water Management Strategies Involving New Sources of Supply in the 2006 Brazos G Regional Water Plan (continued)

Strategy	WUG or WWP	New Supply by 2060 (acft/yr)	Total Project Cost (2nd Quarter 2002 Prices)
New Reservoirs			
Wheeler Branch Off-Channel Reservoir	Somervell County - Other	1,800	$27,195,000
Brushy Creek Reservoir	City of Marlin	2,000	$6,301,610
Total New Reservoirs		**3,800**	**$33,496,610**
Systems Approaches			
West Central Brazos System Optimization Plan	City of Abilene	59,150	$198,055,000
	West Central Texas Municipal Water District		
	Irrigation – Throckmorton County		
BRA System Operation (Excluding Lake Granger Augmentation)	Bell County WCID #1	3,500	$0
	Bosque County – Other	475	
	Manufacturing – Bosque County	1,300	$25,492,000
	Steam-Electric – Bosque County	8,225	
	Brandon-Irene WSC	100	
	City of Hillsboro	100	
	White Bluff Community WS	700	$36,151,000
	Woodrow-Osceola WSC	200	
	Manufacturing – Hill County	100	
	Steam-Electric – Limestone County	16,000	ND
	Other Needs to be Met from BRA System Operation[3]	234,373	ND
Total from Systems Approaches		**324,223**	**> $259,698,000**
Groundwater Development			
Brackish Groundwater	Mining - Nolan County	200	$268,188
Champion Well Field Phases 1 & 2	City of Sweetwater	736	$17,060,471
Carrizo-Wilcox Aquifer – Lee and Milam Counties [BRA System Operation (Lake Granger Augmentation)]	Williamson County entities, see BRA System Operation (Lake Granger Augmentation) (above)	28,263[2]	–
Carrizo-Wilcox Aquifer – Brazos County	City of Bryan	15,300	$33,380,000
	City of College Station		
	Wickson Creek SUD		
	Brazos County – Manufacturing		
Carrizo-Wilcox Aquifer – Burleson County	Manufacturing – Burleson County	150	$124,624 (Annual)
	Irrigation – Burleson County	5,000	$8,718,000

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Table ES-3.
Summary of Recommended Water Management Strategies Involving New Sources of Supply in the 2006 Brazos G Regional Water Plan (concluded)

Strategy	WUG or WWP	New Supply by 2060 (acft/yr)	Total Project Cost (2^{nd} Quarter 2002 Prices)
Carrizo-Wilcox Aquifer – Falls County	Falls County – Other	300	$1,376,000
Carrizo-Wilcox Aquifer – Lee County	Aqua WSC	300	$1,047,000
	City of Giddings	400	$2,099,000
	Lee County WSC	750	$1,762,000
	City of Hutto	1,680	$1,927,000 (Annual)
Carrizo-Wilcox Aquifer – Limestone County	City of Groesbeck	100	$566,000
	Manufacturing – Limestone County	100	$566,000
Carrizo-Wilcox Aquifer – Milam County	Southwest Milam WSC	600	$2,079,000
	Steam-Electric – Milam County	8,200	$3,923,000
	City of Hutto	1,680	$1,927,000 (Annual)
Carrizo-Wilcox Aquifer – Robertson County	Robertson County (Manufacturing)	85	$707,000
Trinity Aquifer – Coryell County	Coryell County – Other	1,200	$4,821,000
Trinity Aquifer – Erath County	Manufacturing – Erath County	50	$198,000
Trinity Aquifer – Lampasas County	Lampasas County – Other	850	$2,576,000
Trinity Aquifer – Williamson County	City of Florence	250	$803,500
Gulf Coast Aquifer – Grimes County	Manufacturing – Grimes County	250	$312,000
Total Groundwater Development		**66,444**	**> $86,116,159**
Total New Supplies		**590,426**	**> $1,030,366,769**

1. Not Determined.
2. The Lake Granger Augmentation includes development of an average annual supply of groundwater from the Carrizo-Wilcox Aquifer of 28,263 acft/yr to develop the total new supply of 54,390 acft/yr (Volume II, Section 4B.5).
3. Includes additional BRA contractual commitments not specifically identified in Section 4B.4. Does not include Region H supplies, but does include minor increases to Region C.

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Table 5.3
Potential New Reservoirs for Region C Water Supply

Name	Region	County	Basin	Stream	Yield in Acre-Feet/Year Holding All Inflow	Yield: With Releases*	Yield: Source	Estimated Capital Cost: Previous Estimate	Base Year	1999 Cost	Year 2000 Cost per Ac-Ft/Yr	Approximate Delivery Distance (Miles)	Environmental Impacts: Acres Flooded	Wetland Impacts	Bottomland Hardwood	Endangered Species	Other Issues	Interbasin Transfer Required?	Region C Entities Interested	Comments
Tehuacana	**C**	**Freestone**	**Trinity**	**Tehuacana Creek**	**68,300**	**64,900****	**A, D**	**$113,121,000**	**1989**	**$196,402,000**	**$3,026**	**90**	**14,900**	**Moderate**	**Moderate**	**Low**	**Lignite**	**No**	**TRWD**	
Muenster	**C**	**Cooke**	**Trinity**	**Brushy Elm Creek**	**500**		**B**					**5**		**Low**	**Low**	**Low**		**No**	**Muenster**	
Roanoke	C	Denton	Trinity	Denton Creek	26,800		G					0		Moderate	Low	Low	Urban development	No	None	Yield is from increase to Lake Grapevine yield.
Upper Red Oak	C	Ellis	Trinity	Red Oak Creek		4,700	G					0		Moderate	Low	Low		No	None	
Lower Red Oak	C	Ellis	Trinity	Red Oak Creek		7,200	G					0		Moderate	Low	Low		No	None	
Boyd	C	Wise	Trinity	West Fork Trinity								0		Low	Low	Low		No	None	
Italy	C	Ellis	Trinity	Chambers Creek	56,000	7,200	A, G					10	12,900	Moderate	Low	Moderate	Downstream water rights	No	None	Yield limited by prior rights.
Tennessee Colony	C	Anderson/Freestone/ Henderson/Navarro	Trinity	Trinity River	300,100+	285,100**	A, D	$621,112,000	1989	$838,501,000	$2,941	100	85,100	High	High	Moderate	Lignite, mitigation land	No	None	
Lower Bois d'Arc Creek	**C**	**Fannin**	**Red**	**Bois d'Arc Creek**	**124,700**	**123,000**	**C**	**$95,961,000**	**1995**	**$114,846,000**	**$934**	**80**	**16,400**	**Moderate**	**Moderate**	**Low**	**National grassland**	**Yes**	**NTMWD**	
Upper Bois d'Arc Creek	**C**	**Fannin**	**Red**	**Bois d'Arc Creek**								**10**		**Low**	**Low**	**Low**		**No**	**Fannin Co.**	
Ralph Hall	**C**	**Fannin**	**Sulphur**	**North Sulphur River**								**15**		**Low**	**Low**	**Low**	**National grassland**	**Yes**	**Fannin Co.**	
Ringgold	B	Clay	Red	Little Wichita River	27,600		A, D					90	15,000	Low	Low	Low		Yes		
Big Pine	D	Lamar	Red	Big Pine Creek	35,900		A, D					120	5,100	Moderate	Moderate	Low		Yes	None	Yield includes diversions from Red River.
Pecan Bayou	D	Red River	Red	Pecan Bayou	82,000		A					130	16,200	Moderate	Low	Moderate		Yes	None	Yield includes diversions from Red River.
George Parkhouse I (South)	**D**	**Delta/Hopkins**	**Sulphur**	**North Sulphur River**	**122,900**	**119,100**	**A, C, D**	**$167,598,000**	**1995**	**$186,034,000**	**$1,562**	**100**	**29,700**	**Moderate**	**Moderate**	**Low**	**Mitigation land**	**Yes**	**Several**	
George Parkhouse II (North)	**D**	**Delta/Lamar**	**Sulphur**	**South Sulphur River**	**141,200**	**129,700**	**A, C, D**	**$112,095,000**	**1995**	**$126,667,000**	**$977**	**100**	**12,300**	**Moderate**	**Low**	**Low**	**Prime farmland**	**Yes**	**Several**	
Marvin Nichols I (North)	**D**	**Red River/Morris/ Titus**	**Sulphur**	**Sulphur River**	**641,700**	**619,100**	**A, C, D**	**$384,521,000**	**1995**	**$426,818,000**	**$689**	**130**	**62,100**	**High**	**High**	**Low**	**Lignite**	**Yes**	**Several**	
Marvin Nichols II (South)	**D**	**Morris/Titus**	**Sulphur**	**White Oak Creek**	**294,800**	**280,100****	**A**	**$191,081,000**	**1989**	**$250,316,000**	**$894**	**130**	**35,900**	**High**	**Moderate to high**	**Low**	**Mitigation land, oil wells**	**Yes**	**Several**	
Little Cypress	D	Marion/Upshur	Cypress	Little Cypress Bayou	129,000		A, D					150	14,000	High	Moderate	Moderate		Yes	None	
Upper Little Cypress	D	Upshur	Cypress	Little Cypress Bayou	71,700		A					130	24,500	High	Moderate	Moderate		Yes	None	
Black Cypress	D	Marion/Cass	Cypress	Black Cypress Bayou	192,000		A					150	32,200	High	High	Moderate		Yes	None	
Marshall	D	Marion/Upshur	Cypress	Little Cypress Bayou	284,100		A					150	32,300	High	Moderate	Moderate		Yes	None	
Waters Bluff	D	Smith/Upshur/Wood	Sabine	Sabine River	324,000	307,800**	A, F	$489,532,000	1998	$514,009,000	$1,670	120	36,400	High	High	High	Wildlife mangement area, wetland banks	Yes	None	
Carl Estes	D	Van Zandt	Sabine	Sabine River	94,000	89,300**	D, F	$373,815,000	1998	$392,506,000	$4,395	80	24,900	Moderate	Moderate	Moderate	Lignite	Yes	None	
Big Sandy	D	Wood	Sabine	Big Sandy Creek	46,600	44,300**	A, D, F	$82,818,000	1998	$86,959,000	$1,963	110	4,400	Moderate	Moderate to high	Moderate		Yes	None	
Carthage	D	Harrison/Panola/Rusk	Sabine	Sabine River	537,000	510,200**	A, F	$495,838,000	1998	$520,630,000	$1,020	160	41,200	High	High	High		Yes	None	
South Bend	G	Stephens/Young	Brazos	Brazos River	106,700		A, D					100	29,700	Moderate	Low	Moderate	Oil wells	Yes	None	Yield is increase to BRA system.
Bedias	H	Grimes/Madison/Walker	Trinity	Bedias Creek	78,500	74,600**	D, H	$147,245,000	1989	$198,781,000	$2,665	170	24,700	Moderate	Low	Moderate		No	TRA	Not for Region C.
Ponta	I	Cherokee/Nacogdoches/Rus	Neches	Angelina River	163,700		A					150	36,800	High	Moderate	Moderate		Yes	None	
Eastex	I	Cherokee	Neches	Mud Creek	85,500		A, D					140	10,000	Moderate	Moderate	Moderate		Yes	None	Has TNRCC permit.
Weches	I	Anderson/Cherokee	Neches	Neches River	193,000		A, D					140	33,100	High	High	Moderate		Yes	None	
Rockland	I	Angelina/Polk/Trinity	Neches	Neches River	555,400		A, D					200	101,100	High	High	Moderate to high	Timber	Yes	None	

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Notes: * Releases are to allow full diversions for downstream water rights and to satisfy TWDB consensus criteria for instream flows. Releases were assumed to reduce yield by 5% if data were not available.
** Releases were assumed to reduce yield by 5% for these reservoirs.
+ Yield for Tennessee Colony does not include return flows.
Reservoirs shown in bold were retained for further study.

I-69/TTC - Tier One DEIS

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The I-69/TTC Tier One Draft Environmental Impact Statement (DEIS) was released for public review and comment on November 9, 2007. Use the links below to view the DEIS; visit the Environmental Studies and Maps page to learn more about the DEIS and the I-69/TTC environmental process. Please click on document title to see a document description.

View Detailed Maps of Recommended Preferred Alternative (narrowed study area)

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Appendix I

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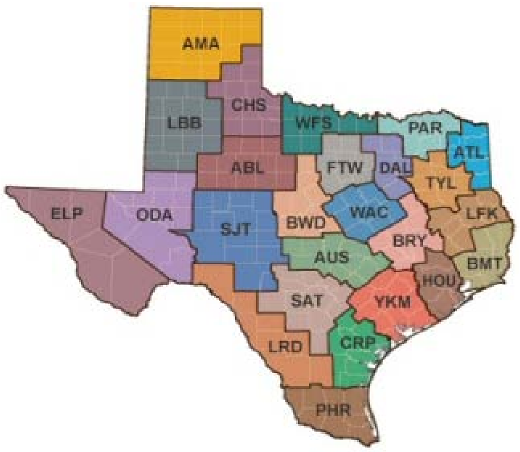

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I-69/TTC

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Project Overview

Interstate 69 is a planned 1,600-mile national highway serving the United States between the borders of Mexico and Canada. Eight states are involved in the project. In Texas, I-69 will be developed as part of the Trans-Texas Corridor (TTC) master plan. The proposed I-69/TTC study area extends from Texarkana/Shreveport to Mexico (possibly the Rio Grande Valley or Laredo).

Environmental Studies and Maps

The environmental studies for I-69/TTC follow the stringent federal rules of the National Environmental Policy Act (NEPA) of 1969. A tiered NEPA approach is being utilized to study the project. Tier One will be used to narrow the project study area. Tier Two will determine needed modal improvement, final route alignments, as well as identify potential project impacts, costs, and mitigation measures. Learn how I-69/TTC has progressed so far, where we are in the environmental process, and what the next steps will be.

Speed Link: I-69/TTC Tier One Draft Environmental Impact Statement (DEIS)

Speed Link: Recommended Preferred Corridors and Upgradeable Facilities Map (Official Tier One DEIS Map)

Speed Link: TxDOT Recommended I-69/TTC developed using existing highways facilities whenever possible (This map will be recommended for the Tier One FEIS)

View Detailed Maps of Recommended Preferred Alternative (narrowed study area)

Project Planning & Development

View information on the I-69/TTC planning process, funding and delivery options, and contracts.

Speed Link: Zachry American Infrastructure and ACS (Zachry-ACS) proposal

Primary Facilities

Some I-69/TTC facilities could be constructed upon completion of the Tier Two environmental studies and in response to a demonstrated transportation need. These facilities would serve as main I-69/TTC arteries, with potential connecting facilities playing a supporting role in traffic movement and access. Specific alignments will not be determined until Tier Two studies are complete; furthermore, these facilities have not yet been identified. Please view the Environmental Studies and Maps page for additional information on the two-tiered I-69/TTC environmental process.

Potential Connecting Facilities
Later this year, five Corridor Segment Advisory Committees will be formed to specifically provide input and advice to TxDOT regarding specific routes or components of the I-69/TTC program that would be needed for a particular corridor segment, and also what improvements are needed for existing transportation facilities. The corridor segment advisory committees will be appointed by local entities.

Questions and Comments
Find out how to voice your opinion and get answers to your I-69/TTC questions.

Mailing List
Sign up for the I-69/TTC mailing to stay informed about the project.

Public Meetings
View information on previous or upcoming public meetings.

News
Read I-69/TTC press releases.

Library/Archive
View past and current public meeting handouts, environmental documents, news releases, and other important Project materials.

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DP-4. **Profile of Selected Housing Characteristics: 2000**
Data Set: Census 2000 Summary File 3 (SF 3) - Sample Data
Geographic Area: **Freestone County, Texas**

NOTE: Data based on a sample except in P3, P4, H3, and H4. For information on confidentiality protection, sampling error, nonsampling error, definitions, and count corrections see http://factfinder.census.gov/home/en/datanotes/expsf3.htm.

Subject	Number	Percent
Total housing units	**8,138**	**100.0**
UNITS IN STRUCTURE		
1-unit, detached	5,642	69.3
1-unit, attached	75	0.9
2 units	162	2.0
3 or 4 units	107	1.3
5 to 9 units	24	0.3
10 to 19 units	47	0.6
20 or more units	54	0.7
Mobile home	1,917	23.6
Boat, RV, van, etc.	110	1.4
YEAR STRUCTURE BUILT		
1999 to March 2000	264	3.2
1995 to 1998	695	8.5
1990 to 1994	629	7.7
1980 to 1989	1,641	20.2
1970 to 1979	1,819	22.4
1960 to 1969	981	12.1
1940 to 1959	1,213	14.9
1939 or earlier	896	11.0
ROOMS		
1 room	57	0.7
2 rooms	297	3.6
3 rooms	539	6.6
4 rooms	1,797	22.1
5 rooms	2,261	27.8
6 rooms	1,797	22.1
7 rooms	737	9.1
8 rooms	374	4.6
9 or more rooms	279	3.4
Median (rooms)	5.1	(X)
Occupied Housing Units	**6,588**	**100.0**
YEAR HOUSEHOLDER MOVED INTO UNIT		
1999 to March 2000	1,156	17.5
1995 to 1998	1,771	26.9
1990 to 1994	1,116	16.9
1980 to 1989	1,133	17.2
1970 to 1979	731	11.1
1969 or earlier	681	10.3
VEHICLES AVAILABLE		
None	410	6.2
1	2,117	32.1
2	2,773	42.1
3 or more	1,288	19.6
HOUSE HEATING FUEL		
Utility gas	1,872	28.4
Bottled, tank, or LP gas	1,413	21.4
Electricity	3,168	48.1
Fuel oil, kerosene, etc.	34	0.5
Coal or coke	0	0.0
Wood	92	1.4
Solar energy	0	0.0

Subject	Number	Percent
Other fuel	5	0.1
No fuel used	4	0.1
SELECTED CHARACTERISTICS		
Lacking complete plumbing facilities	53	0.8
Lacking complete kitchen facilities	37	0.6
No telephone service	365	5.5
OCCUPANTS PER ROOM		
Occupied housing units	**6,588**	**100.0**
1.00 or less	6,315	95.9
1.01 to 1.50	190	2.9
1.51 or more	83	1.3
Specified owner-occupied units	**3,108**	**100.0**
VALUE		
Less than $50,000	1,315	42.3
$50,000 to $99,999	1,327	42.7
$100,000 to $149,999	265	8.5
$150,000 to $199,999	107	3.4
$200,000 to $299,999	53	1.7
$300,000 to $499,999	23	0.7
$500,000 to $999,999	14	0.5
$1,000,000 or more	4	0.1
Median (dollars)	56,000	(X)
MORTGAGE STATUS AND SELECTED MONTHLY OWNER COSTS		
With a mortgage	1,293	41.6
Less than $300	22	0.7
$300 to $499	225	7.2
$500 to $699	458	14.7
$700 to $999	362	11.6
$1,000 to $1,499	192	6.2
$1,500 to $1,999	11	0.4
$2,000 or more	23	0.7
Median (dollars)	669	(X)
Not mortgaged	1,815	58.4
Median (dollars)	254	(X)
SELECTED MONTHLY OWNER COSTS AS A PERCENTAGE OF HOUSEHOLD INCOME IN 1999		
Less than 15 percent	1,557	50.1
15 to 19 percent	478	15.4
20 to 24 percent	287	9.2
25 to 29 percent	137	4.4
30 to 34 percent	120	3.9
35 percent or more	481	15.5
Not computed	48	1.5
Specified renter-occupied units	**1,347**	**100.0**
GROSS RENT		
Less than $200	140	10.4
$200 to $299	201	14.9
$300 to $499	437	32.4
$500 to $749	247	18.3
$750 to $999	41	3.0
$1,000 to $1,499	5	0.4
$1,500 or more	0	0.0
No cash rent	276	20.5
Median (dollars)	378	(X)
GROSS RENT AS A PERCENTAGE OF HOUSEHOLD INCOME IN 1999		
Less than 15 percent	364	27.0
15 to 19 percent	172	12.8
20 to 24 percent	58	4.3
25 to 29 percent	113	8.4
30 to 34 percent	55	4.1
35 percent or more	273	20.3
Not computed	312	23.2

(X) Not applicable.
Source: U.S. Census Bureau, Census 2000 Summary File 3, Matrices H1, H7, H20, H23, H24, H30, H34, H38, H40, H43,

H44, H48, H51, H62, H63, H69, H74, H76, H90, H91, and H94

U.S. Census Bureau
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POPULATION FINDER

United States | Texas | Denison city

Denison city, Texas

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denison
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Texas
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search by address »

The 2008 population estimate for Denison city, Texas is 24,001.

Note: Information about challenges to population estimates data can be found on the Population Estimates Challenges page.

View population trends...

	2008	2000	1990
Population	24,001	22,773	21,505

Source: U.S. Census Bureau, 2008 Population Estimates, Census 2000, 1990 Census

View more results...

Population for all cities and towns in Texas, 2000-2008:

alphabetic | ranked

Map of Persons per Square Mile, City/Town by Census Tract:

2000 | 1990

See more data for Denison city, Texas on the Fact Sheet.

The letters PDF or symbol indicate a document is in the Portable Document Format (PDF). To view the file you will need the Adobe® Acrobat® Reader, which is available for **free** from the Adobe web site.

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United States | Texas | **Fannin County**

Fannin County, Texas

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fannin county
state
Texas GO
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The 2008 population estimate for Fannin County, Texas is 33,229.

Note: Information about challenges to population estimates data can be found on the Population Estimates Challenges page.

View population trends...

	2008	2000	1990
Population	33,229	31,242	24,804

Source: U.S. Census Bureau, 2008 Population Estimates, Census 2000, 1990 Census

View more results...

Population for all counties in Texas, 2000-2008:

alphabetic | ranked

Map of Persons per Square Mile, Texas by County:

2008 | 2000 | 1990

Map of Persons per Square Mile, County by County Subdivision:

2008 | 2000 | 1990

See more data for Fannin County, Texas on the Fact Sheet.

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American FactFinder

POPULATION FINDER

United States | Texas | Savoy city

Savoy city, Texas

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The 2008 population estimate for Savoy city, Texas is 895.

Note: Information about challenges to population estimates data can be found on the Population Estimates Challenges page.

View population trends...

	2008	2000	1990
Population	895	850	877

Source: U.S. Census Bureau, 2008 Population Estimates, Census 2000, 1990 Census

View more results...

Population for all cities and towns in Texas, 2000-2008:

alphabetic | ranked

Map of Persons per Square Mile, City/Town by Census Tract:

2000 | 1990

See more data for Savoy city, Texas on the Fact Sheet.

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Data Profile

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2008 Data Profiles:
▸ Social
Economic
Housing
Demographic
Narrative

2008 Comparison Profile

View this table...
▸ from 2008
from 2007
from 2006
from 2005

View this table...
for other geographies (state, county, place...)

- Subject Definitions
- Quality Measures

Sherman-Denison, TX Metropolitan Statistical Area

Selected Social Characteristics in the United States: 2008

Data Set: 2008 American Community Survey 1-Year Estimates
Survey: American Community Survey

Social - Education, Marital Status, Relationships, Fertility, Grandparents...
Economic - Income, Employment, Occupation, Commuting to Work...
Housing - Occupancy and Structure, Housing Value and Costs, Utilities...
Demographic - Sex and Age, Race, Hispanic Origin, Housing Units...
Narrative - Text profile with graphs for easy analysis...

NOTE. Although the American Community Survey (ACS) produces population, demographic and housing unit estimates, it is the Census Bureau's Population Estimates Program that produces and disseminates the official estimates of the population for the nation, states, counties, cities and towns and estimates of housing units for states and counties.

For more information on confidentiality protection, sampling error, nonsampling error, and definitions, see Survey Methodology.

Selected Social Characteristics in the United States	Estimate	Margin of Error	Percent	Margin of Error
HOUSEHOLDS BY TYPE				
Total households	44,588	+/-1,727	44,588	(X)
Family households (families)	31,668	+/-1,933	71.0%	+/-3.5
With own children under 18 years	14,563	+/-1,432	32.7%	+/-2.7
Married-couple family	23,907	+/-1,812	53.6%	+/-3.4
With own children under 18 years	9,984	+/-1,264	22.4%	+/-2.5
Male householder, no wife present, family	2,387	+/-686	5.4%	+/-1.5
With own children under 18 years	1,044	+/-496	2.3%	+/-1.1
Female householder, no husband present, family	5,374	+/-935	12.1%	+/-2.1
With own children under 18 years	3,535	+/-904	7.9%	+/-2.0
Nonfamily households	12,920	+/-1,653	29.0%	+/-3.5
Householder living alone	10,955	+/-1,558	24.6%	+/-3.3
65 years and over	4,458	+/-954	10.0%	+/-2.1
Households with one or more people under 18 years	16,003	+/-1,504	35.9%	+/-2.9
Households with one or more people 65 years and over	11,586	+/-890	26.0%	+/-1.9
Average household size	2.57	+/-0.08	(X)	(X)
Average family size	3.07	+/-0.14	(X)	(X)
RELATIONSHIP				
Population in households	114,554	+/-2,867	114,554	(X)
Householder	44,588	+/-1,727	38.9%	+/-1.3
Spouse	23,959	+/-1,869	20.9%	+/-1.6
Child	32,874	+/-2,057	28.7%	+/-1.6
Other relatives	8,877	+/-2,158	7.7%	+/-1.9
Nonrelatives	4,256	+/-1,099	3.7%	+/-1.0
Unmarried partner	2,557	+/-862	2.2%	+/-0.8
MARITAL STATUS				
Males 15 years and over	45,511	+/-508	45,511	(X)
Never married	12,603	+/-1,509	27.7%	+/-3.2
Now married, except separated	25,998	+/-1,829	57.1%	+/-4.1
Separated	1,139	+/-549	2.5%	+/-1.2
Widowed	937	+/-448	2.1%	+/-1.0
Divorced	4,834	+/-998	10.6%	+/-2.2
Females 15 years and over	49,394	+/-565	49,394	(X)
Never married	9,888	+/-1,332	20.0%	+/-2.6
Now married, except separated	25,605	+/-1,859	51.8%	+/-3.9

Separated	867	+/-442	1.8%	+/-0.9
Widowed	5,455	+/-955	11.0%	+/-1.9
Divorced	7,579	+/-1,472	15.3%	+/-3.0
FERTILITY				
Number of women 15 to 50 years old who had a birth in the past 12 months	2,051	+/-622	2,051	(X)
Unmarried women (widowed, divorced, and never married)	673	+/-356	32.8%	+/-15.3
Per 1,000 unmarried women	49	+/-26	(X)	(X)
Per 1,000 women 15 to 50 years old	70	+/-22	(X)	(X)
Per 1,000 women 15 to 19 years old	67	+/-58	(X)	(X)
Per 1,000 women 20 to 34 years old	153	+/-51	(X)	(X)
Per 1,000 women 35 to 50 years old	1	+/-2	(X)	(X)
GRANDPARENTS				
Number of grandparents living with own grandchildren under 18 years	2,535	+/-965	2,535	(X)
Responsible for grandchildren	1,846	+/-791	72.8%	+/-13.6
Years responsible for grandchildren				
Less than 1 year	276	+/-258	10.9%	+/-10.3
1 or 2 years	709	+/-393	28.0%	+/-14.0
3 or 4 years	340	+/-292	13.4%	+/-10.1
5 or more years	521	+/-502	20.6%	+/-16.2
Number of grandparents responsible for own grandchildren under 18 years	1,846	+/-791	1,846	(X)
Who are female	1,174	+/-465	63.6%	+/-7.8
Who are married	1,367	+/-728	74.1%	+/-13.8
SCHOOL ENROLLMENT				
Population 3 years and over enrolled in school	29,664	+/-1,661	29,664	(X)
Nursery school, preschool	2,071	+/-685	7.0%	+/-2.3
Kindergarten	1,637	+/-602	5.5%	+/-2.0
Elementary school (grades 1-8)	12,242	+/-881	41.3%	+/-3.3
High school (grades 9-12)	5,988	+/-1,005	20.2%	+/-3.6
College or graduate school	7,726	+/-1,828	26.0%	+/-5.2
EDUCATIONAL ATTAINMENT				
Population 25 years and over	78,674	+/-630	78,674	(X)
Less than 9th grade	4,756	+/-890	6.0%	+/-1.1
9th to 12th grade, no diploma	6,168	+/-1,276	7.8%	+/-1.6
High school graduate (includes equivalency)	26,753	+/-2,288	34.0%	+/-2.9
Some college, no degree	22,536	+/-2,221	28.6%	+/-2.8
Associate's degree	6,067	+/-1,273	7.7%	+/-1.6
Bachelor's degree	8,269	+/-1,449	10.5%	+/-1.8
Graduate or professional degree	4,125	+/-974	5.2%	+/-1.2
Percent high school graduate or higher	86.1%	+/-1.8	(X)	(X)
Percent bachelor's degree or higher	15.8%	+/-2.4	(X)	(X)
VETERAN STATUS				
Civilian population 18 years and over	89,969	+/-314	89,969	(X)
Civilian veterans	10,312	+/-1,265	11.5%	+/-1.4
DISABILITY STATUS OF THE CIVILIAN NONINSTITUTIONALIZED POPULATION				
Total Civilian Noninstitutionalized Population	116,739	+/-1,182	116,739	(X)
With a disability	15,396	+/-2,057	13.2%	+/-1.8
Under 18 years	28,732	+/-305	28,732	(X)
With a disability	580	+/-346	2.0%	+/-1.2
18 to 64 years	71,835	+/-1,147	71,835	(X)
With a disability	7,710	+/-1,432	10.7%	+/-2.0
65 years and over	16,172	+/-922	16,172	(X)
With a disability	7,106	+/-1,202	43.9%	+/-6.8

RESIDENCE 1 YEAR AGO				
Population 1 year and over	117,051	+/-547	117,051	(X)
Same house	95,028	+/-3,886	81.2%	+/-3.2
Different house in the U.S.	21,504	+/-3,654	18.4%	+/-3.2
Same county	13,982	+/-3,014	11.9%	+/-2.6
Different county	7,522	+/-2,092	6.4%	+/-1.8
Same state	5,565	+/-1,714	4.8%	+/-1.5
Different state	1,957	+/-803	1.7%	+/-0.7
Abroad	519	+/-320	0.4%	+/-0.3
PLACE OF BIRTH				
Total population	118,804	*****	118,804	(X)
Native	112,387	+/-1,254	94.6%	+/-1.1
Born in United States	110,838	+/-1,394	93.3%	+/-1.2
State of residence	78,626	+/-2,836	66.2%	+/-2.4
Different state	32,212	+/-2,353	27.1%	+/-2.0
Born in Puerto Rico, U.S. Island areas, or born abroad to American parent(s)	1,549	+/-609	1.3%	+/-0.5
Foreign born	6,417	+/-1,254	5.4%	+/-1.1
U.S. CITIZENSHIP STATUS				
Foreign-born population	6,417	+/-1,254	6,417	(X)
Naturalized U.S. citizen	1,673	+/-740	26.1%	+/-11.2
Not a U.S. citizen	4,744	+/-1,266	73.9%	+/-11.2
YEAR OF ENTRY				
Population born outside the United States	7,966	+/-1,394	7,966	(X)
Native	1,549	+/-609	1,549	(X)
Entered 2000 or later	79	+/-134	5.1%	+/-9.1
Entered before 2000	1,470	+/-620	94.9%	+/-9.1
Foreign born	6,417	+/-1,254	6,417	(X)
Entered 2000 or later	2,532	+/-1,053	39.5%	+/-13.3
Entered before 2000	3,885	+/-1,059	60.5%	+/-13.3
WORLD REGION OF BIRTH OF FOREIGN BORN				
Foreign-born population, excluding population born at sea	N	N	N	(X)
Europe	N	N	N	N
Asia	N	N	N	N
Africa	N	N	N	N
Oceania	N	N	N	N
Latin America	N	N	N	N
Northern America	N	N	N	N
LANGUAGE SPOKEN AT HOME				
Population 5 years and over	N	N	N	(X)
English only	N	N	N	N
Language other than English	N	N	N	N
Speak English less than "very well"	N	N	N	N
Spanish	N	N	N	N
Speak English less than "very well"	N	N	N	N
Other Indo-European languages	N	N	N	N
Speak English less than "very well"	N	N	N	N
Asian and Pacific Islander languages	N	N	N	N
Speak English less than "very well"	N	N	N	N
Other languages	N	N	N	N
Speak English less than "very well"	N	N	N	N
ANCESTRY				
Total population	118,804	*****	118,804	(X)
American	10,510	+/-2,326	8.8%	+/-2.0
Arab	289	+/-338	0.2%	+/-0.3
Czech	429	+/-306	0.4%	+/-0.3
Danish	39	+/-64	0.0%	+/-0.1
Dutch	3,399	+/-1,214	2.9%	+/-1.0
English	14,376	+/-2,686	12.1%	+/-2.3
French (except Basque)	4,063	+/-993	3.4%	+/-0.8

French Canadian	548	+/-356	0.5%	+/-0.3
German	15,157	+/-2,338	12.8%	+/-2.0
Greek	100	+/-137	0.1%	+/-0.1
Hungarian	0	+/-291	0.0%	+/-0.2
Irish	17,581	+/-2,552	14.8%	+/-2.1
Italian	3,438	+/-1,775	2.9%	+/-1.5
Lithuanian	51	+/-89	0.0%	+/-0.1
Norwegian	528	+/-393	0.4%	+/-0.3
Polish	1,540	+/-785	1.3%	+/-0.7
Portuguese	341	+/-381	0.3%	+/-0.3
Russian	375	+/-402	0.3%	+/-0.3
Scotch-Irish	1,545	+/-652	1.3%	+/-0.5
Scottish	3,009	+/-1,206	2.5%	+/-1.0
Slovak	0	+/-291	0.0%	+/-0.2
Subsaharan African	644	+/-777	0.5%	+/-0.7
Swedish	1,322	+/-1,043	1.1%	+/-0.9
Swiss	223	+/-352	0.2%	+/-0.3
Ukrainian	82	+/-134	0.1%	+/-0.1
Welsh	323	+/-224	0.3%	+/-0.2
West Indian (excluding Hispanic origin groups)	285	+/-248	0.2%	+/-0.2

Source: U.S. Census Bureau, 2008 American Community Survey

Data are based on a sample and are subject to sampling variability. The degree of uncertainty for an estimate arising from sampling variability is represented through the use of a margin of error. The value shown here is the 90 percent margin of error. The margin of error can be interpreted roughly as providing a 90 percent probability that the interval defined by the estimate minus the margin of error and the estimate plus the margin of error (the lower and upper confidence bounds) contains the true value. In addition to sampling variability, the ACS estimates are subject to nonsampling error (for a discussion of nonsampling variability, see Accuracy of the Data). The effect of nonsampling error is not represented in these tables.

Notes:
·Ancestry listed in this table refers to the total number of people who responded with a particular ancestry; for example, the estimate given for Russian represents the number of people who listed Russian as either their first or second ancestry. This table lists only the largest ancestry groups; see the Detailed Tables for more categories. Race and Hispanic origin groups are not included in this table because official data for those groups come from the Race and Hispanic origin questions rather than the ancestry question (see Demographic Table).
·Starting in 2008, the Scotch-Irish category does not include Irish-Scotch.
·The Census Bureau introduced a new set of disability questions in the 2008 ACS questionnaire. Accordingly, comparisons of disability data from 2008 or later with data from prior years are not recommended. For more information on these questions and their evaluation in the 2006 ACS Content Test, see the Evaluation Report Covering Disability.
·Data for year of entry of the native population reflect the year of entry into the U.S. by people who were born in Puerto Rico, U.S. Island Areas or born outside the U.S. to a U.S. citizen parent and who subsequently moved to the U.S.
·Due to a reduction in the Failed Edit Follow-up (FEFU) operation for 4-months in 2008, there was an increase in the amount of missing data and an increase in item allocation rates. For more information see the ACS User Notes.
·While the 2008 American Community Survey (ACS) data generally reflect the November 2007 Office of Management and Budget (OMB) definitions of metropolitan and micropolitan statistical areas; in certain instances the names, codes, and boundaries of the principal cities shown in ACS tables may differ from the OMB definitions due to differences in the effective dates of the geographic entities. The 2008 Puerto Rico Community Survey (PRCS) data generally reflect the November 2007 Office of Management and Budget (OMB) definitions of metropolitan and micropolitan statistical areas; in certain instances the names, codes, and boundaries of the principal cities shown in PRCS tables may differ from the OMB definitions due to differences in the effective dates of the geographic entities.
·Estimates of urban and rural population, housing units, and characteristics reflect boundaries of urban areas defined based on Census 2000 data. Boundaries for urban areas have not been updated since Census 2000. As a result, data for urban and rural areas from the ACS do not necessarily reflect the results of ongoing urbanization.

Explanation of Symbols:
1. An '**' entry in the margin of error column indicates that either no sample observations or too few sample observations were available to compute a standard error and thus the margin of error. A statistical test is not appropriate.
2. An '-' entry in the estimate column indicates that either no sample observations or too few sample observations were available to compute an estimate, or a ratio of medians cannot be calculated because one or both of the median estimates falls in the lowest interval or upper interval of an open-ended distribution.
3. An '-' following a median estimate means the median falls in the lowest interval of an open-ended distribution.
4. An '+' following a median estimate means the median falls in the upper interval of an open-ended distribution.
5. An '***' entry in the margin of error column indicates that the median falls in the lowest interval or upper interval of an open-ended distribution. A statistical test is not appropriate.
6. An '*****' entry in the margin of error column indicates that the estimate is controlled. A statistical test for sampling variability is not appropriate.
7. An 'N' entry in the estimate and margin of error columns indicates that data for this geographic area cannot be displayed because the number of sample cases is too small.
8. An '(X)' means that the estimate is not applicable or not available.

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Fannin County, Texas
Selected Housing Characteristics: 2006-2008
Data Set: **2006-2008 American Community Survey 3-Year Estimates**
Survey: **American Community Survey**

NOTE. Although the American Community Survey (ACS) produces population, demographic and housing unit estimates, it is the Census Bureau's Population Estimates Program that produces and disseminates the official estimates of the population for the nation, states, counties, cities and towns and estimates of housing units for states and counties.

For more information on confidentiality protection, sampling error, nonsampling error, and definitions, see Survey Methodology.

Selected Housing Characteristics	Estimate	Margin of Error	Percent	Margin of Error
HOUSING OCCUPANCY				
Total housing units	**13,571**	**+/-271**	**13,571**	**(X)**
Occupied housing units	11,425	+/-445	84.2%	+/-3.0
Vacant housing units	2,146	+/-413	15.8%	+/-3.0
Homeowner vacancy rate	2.6	+/-1.8	(X)	(X)
Rental vacancy rate	8.5	+/-4.5	(X)	(X)
UNITS IN STRUCTURE				
Total housing units	**13,571**	**+/-271**	**13,571**	**(X)**
1-unit, detached	10,458	+/-478	77.1%	+/-3.1
1-unit, attached	112	+/-93	0.8%	+/-0.7
2 units	499	+/-180	3.7%	+/-1.3
3 or 4 units	290	+/-128	2.1%	+/-0.9
5 to 9 units	126	+/-102	0.9%	+/-0.8
10 to 19 units	122	+/-70	0.9%	+/-0.5
20 or more units	157	+/-131	1.2%	+/-1.0
Mobile home	1,782	+/-347	13.1%	+/-2.5
Boat, RV, van, etc.	25	+/-39	0.2%	+/-0.3
YEAR STRUCTURE BUILT				
Total housing units	**13,571**	**+/-271**	**13,571**	**(X)**
Built 2005 or later	337	+/-120	2.5%	+/-0.9
Built 2000 to 2004	825	+/-219	6.1%	+/-1.6
Built 1990 to 1999	2,338	+/-347	17.2%	+/-2.6
Built 1980 to 1989	2,368	+/-403	17.4%	+/-2.9
Built 1970 to 1979	2,096	+/-368	15.4%	+/-2.7
Built 1960 to 1969	1,214	+/-293	8.9%	+/-2.1
Built 1950 to 1959	1,108	+/-237	8.2%	+/-1.7
Built 1940 to 1949	1,326	+/-295	9.8%	+/-2.1
Built 1939 or earlier	1,959	+/-283	14.4%	+/-2.0
ROOMS				
Total housing units	**13,571**	**+/-271**	**13,571**	**(X)**
1 room	273	+/-142	2.0%	+/-1.0
2 rooms	105	+/-92	0.8%	+/-0.7
3 rooms	672	+/-223	5.0%	+/-1.6
4 rooms	2,599	+/-395	19.2%	+/-2.8
5 rooms	4,709	+/-429	34.7%	+/-3.2
6 rooms	3,253	+/-481	24.0%	+/-3.5
7 rooms	891	+/-243	6.6%	+/-1.8
8 rooms	493	+/-162	3.6%	+/-1.2
9 rooms or more	576	+/-193	4.2%	+/-1.4
Median rooms	5.2	+/-0.2	(X)	(X)

Selected Housing Characteristics	Estimate	Margin of Error	Percent	Margin of Error
BEDROOMS				
Total housing units	**13,571**	**+/-271**	**13,571**	**(X)**
No bedroom	273	+/-142	2.0%	+/-1.0
1 bedroom	779	+/-222	5.7%	+/-1.6
2 bedrooms	4,103	+/-510	30.2%	+/-3.6
3 bedrooms	6,776	+/-411	49.9%	+/-3.2
4 bedrooms	1,502	+/-312	11.1%	+/-2.3
5 or more bedrooms	138	+/-97	1.0%	+/-0.7
HOUSING TENURE				
Occupied housing units	**11,425**	**+/-445**	**11,425**	**(X)**
Owner-occupied	8,369	+/-476	73.3%	+/-3.2
Renter-occupied	3,056	+/-386	26.7%	+/-3.2
Average household size of owner-occupied unit	2.68	+/-0.10	(X)	(X)
Average household size of renter-occupied unit	2.79	+/-0.22	(X)	(X)
YEAR HOUSEHOLDER MOVED INTO UNIT				
Occupied housing units	**11,425**	**+/-445**	**11,425**	**(X)**
Moved in 2005 or later	3,332	+/-484	29.2%	+/-4.0
Moved in 2000 to 2004	2,744	+/-401	24.0%	+/-3.4
Moved in 1990 to 1999	2,422	+/-349	21.2%	+/-2.9
Moved in 1980 to 1989	1,372	+/-275	12.0%	+/-2.4
Moved in 1970 to 1979	913	+/-293	8.0%	+/-2.6
Moved in 1969 or earlier	642	+/-238	5.6%	+/-2.1
VEHICLES AVAILABLE				
Occupied housing units	**11,425**	**+/-445**	**11,425**	**(X)**
No vehicles available	504	+/-155	4.4%	+/-1.3
1 vehicle available	3,507	+/-356	30.7%	+/-2.9
2 vehicles available	4,715	+/-412	41.3%	+/-3.2
3 or more vehicles available	2,699	+/-303	23.6%	+/-2.5
HOUSE HEATING FUEL				
Occupied housing units	**11,425**	**+/-445**	**11,425**	**(X)**
Utility gas	N	N	N	N
Bottled, tank, or LP gas	N	N	N	N
Electricity	N	N	N	N
Fuel oil, kerosene, etc.	N	N	N	N
Coal or coke	N	N	N	N
Wood	N	N	N	N
Solar energy	N	N	N	N
Other fuel	N	N	N	N
No fuel used	N	N	N	N
SELECTED CHARACTERISTICS				
Occupied housing units	**11,425**	**+/-445**	**11,425**	**(X)**
Lacking complete plumbing facilities	101	+/-89	0.9%	+/-0.8
Lacking complete kitchen facilities	57	+/-66	0.5%	+/-0.6
No telephone service available	466	+/-177	4.1%	+/-1.6
OCCUPANTS PER ROOM				
Occupied housing units	**11,425**	**+/-445**	**11,425**	**(X)**
1.00 or less	11,054	+/-459	96.8%	+/-1.4
1.01 to 1.50	350	+/-163	3.1%	+/-1.4
1.51 or more	21	+/-37	0.2%	+/-0.3
VALUE				
Owner-occupied units	**8,369**	**+/-476**	**8,369**	**(X)**
Less than $50,000	2,113	+/-387	25.2%	+/-3.9
$50,000 to $99,999	3,361	+/-433	40.2%	+/-4.8
$100,000 to $149,999	1,311	+/-266	15.7%	+/-3.2
$150,000 to $199,999	744	+/-190	8.9%	+/-2.3
$200,000 to $299,999	514	+/-173	6.1%	+/-2.0
$300,000 to $499,999	247	+/-113	3.0%	+/-1.4
$500,000 to $999,999	72	+/-59	0.9%	+/-0.7
$1,000,000 or more	7	+/-12	0.1%	+/-0.1
Median (dollars)	77,500	+/-4,712	(X)	(X)

Selected Housing Characteristics	Estimate	Margin of Error	Percent	Margin of Error
MORTGAGE STATUS				
Owner-occupied units	**8,369**	**+/-476**	**8,369**	**(X)**
Housing units with a mortgage	4,327	+/-505	51.7%	+/-4.7
Housing units without a mortgage	4,042	+/-416	48.3%	+/-4.7
SELECTED MONTHLY OWNER COSTS (SMOC)				
Housing units with a mortgage	**4,327**	**+/-505**	**4,327**	**(X)**
Less than $300	0	+/-165	0.0%	+/-1.4
$300 to $499	159	+/-102	3.7%	+/-2.3
$500 to $699	523	+/-213	12.1%	+/-4.5
$700 to $999	1,438	+/-329	33.2%	+/-6.7
$1,000 to $1,499	1,591	+/-339	36.8%	+/-6.7
$1,500 to $1,999	450	+/-154	10.4%	+/-3.4
$2,000 or more	166	+/-83	3.8%	+/-2.0
Median (dollars)	1,012	+/-79	(X)	(X)
Housing units without a mortgage	**4,042**	**+/-416**	**4,042**	**(X)**
Less than $100	24	+/-29	0.6%	+/-0.7
$100 to $199	305	+/-143	7.5%	+/-3.3
$200 to $299	874	+/-255	21.6%	+/-5.7
$300 to $399	769	+/-162	19.0%	+/-3.8
$400 or more	2,070	+/-309	51.2%	+/-6.0
Median (dollars)	407	+/-35	(X)	(X)
SELECTED MONTHLY OWNER COSTS AS A PERCENTAGE OF HOUSEHOLD INCOME (SMOCAPI)				
Housing units with a mortgage (excluding units where SMOCAPI cannot be computed)	**4,310**	**+/-510**	**4,310**	**(X)**
Less than 20.0 percent	1,950	+/-318	45.2%	+/-6.5
20.0 to 24.9 percent	794	+/-235	18.4%	+/-4.7
25.0 to 29.9 percent	444	+/-190	10.3%	+/-4.2
30.0 to 34.9 percent	428	+/-173	9.9%	+/-3.8
35.0 percent or more	694	+/-232	16.1%	+/-4.9
Not computed	17	+/-17	(X)	(X)
Housing unit without a mortgage (excluding units where SMOCAPI cannot be computed)	**3,946**	**+/-412**	**3,946**	**(X)**
Less than 10.0 percent	1,270	+/-217	32.2%	+/-4.9
10.0 to 14.9 percent	905	+/-215	22.9%	+/-5.0
15.0 to 19.9 percent	532	+/-159	13.5%	+/-3.9
20.0 to 24.9 percent	386	+/-166	9.8%	+/-4.0
25.0 to 29.9 percent	161	+/-106	4.1%	+/-2.6
30.0 to 34.9 percent	101	+/-80	2.6%	+/-1.9
35.0 percent or more	591	+/-205	15.0%	+/-4.9
Not computed	96	+/-83	(X)	(X)
GROSS RENT				
Occupied units paying rent	**2,591**	**+/-354**	**2,591**	**(X)**
Less than $200	107	+/-71	4.1%	+/-2.7
$200 to $299	42	+/-34	1.6%	+/-1.3
$300 to $499	476	+/-171	18.4%	+/-6.5
$500 to $749	1,158	+/-268	44.7%	+/-8.1
$750 to $999	503	+/-159	19.4%	+/-5.6
$1,000 to $1,499	285	+/-135	11.0%	+/-4.8
$1,500 or more	20	+/-31	0.8%	+/-1.2
Median (dollars)	667	+/-44	(X)	(X)
No rent paid	465	+/-176	(X)	(X)
GROSS RENT AS A PERCENTAGE OF HOUSEHOLD INCOME (GRAPI)				
Occupied units paying rent (excluding units where GRAPI cannot be computed)	**2,584**	**+/-351**	**2,584**	**(X)**
Less than 15.0 percent	482	+/-193	18.7%	+/-6.8
15.0 to 19.9 percent	371	+/-184	14.4%	+/-6.8
20.0 to 24.9 percent	224	+/-120	8.7%	+/-4.5
25.0 to 29.9 percent	239	+/-116	9.2%	+/-4.5
30.0 to 34.9 percent	204	+/-123	7.9%	+/-4.6
35.0 percent or more	1,064	+/-239	41.2%	+/-7.4

Selected Housing Characteristics	Estimate	Margin of Error	Percent	Margin of Error
Not computed	472	+/-175	(X)	(X)

Source: U.S. Census Bureau, 2006-2008 American Community Survey

Data are based on a sample and are subject to sampling variability. The degree of uncertainty for an estimate arising from sampling variability is represented through the use of a margin of error. The value shown here is the 90 percent margin of error. The margin of error can be interpreted roughly as providing a 90 percent probability that the interval defined by the estimate minus the margin of error and the estimate plus the margin of error (the lower and upper confidence bounds) contains the true value. In addition to sampling variability, the ACS estimates are subject to nonsampling error (for a discussion of nonsampling variability, see Accuracy of the Data). The effect of nonsampling error is not represented in these tables.

Notes:
·In prior years, the universe included all owner-occupied units with a mortgage. It is now restricted to include only those units where SMOCAPI is computed, that is, SMOC and household income are valid values.
·In prior years, the universe included all owner-occupied units without a mortgage. It is now restricted to include only those units where SMOCAPI is computed, that is, SMOC and household income are valid values.
·In prior years, the universe included all renter-occupied units. It is now restricted to include only those units where GRAPI is computed, that is, gross rent and household Income are valid values.
·Due to the use of value categories rather than specific amounts collected for each individual housing unit in 2006 and 2007, property value on the 3-year file cannot be inflation adjusted. Any table providing data on property values is reported in current dollars. This is in contrast to the other monetary data on the 3-year file, which are inflated to 2008 dollars.
·The estimate for mortgage status and selected monthly owner costs, median mortgage status and selected monthly owner costs, gross rent, and median gross rent for previous years is adjusted for inflation to the current year.
·The median gross rent excludes no cash renters.
·While the 2008 American Community Survey (ACS) data generally reflect the November 2007 Office of Management and Budget (OMB) definitions of metropolitan and micropolitan statistical areas; in certain instances the names, codes, and boundaries of the principal cities shown in ACS tables may differ from the OMB definitions due to differences in the effective dates of the geographic entities. The 2008 Puerto Rico Community Survey (PRCS) data generally reflect the November 2007 Office of Management and Budget (OMB) definitions of metropolitan and micropolitan statistical areas; in certain instances the names, codes, and boundaries of the principal cities shown in PRCS tables may differ from the OMB definitions due to differences in the effective dates of the geographic entities.
·Estimates of urban and rural population, housing units, and characteristics reflect boundaries of urban areas defined based on Census 2000 data. Boundaries for urban areas have not been updated since Census 2000. As a result, data for urban and rural areas from the ACS do not necessarily reflect the results of ongoing urbanization.

Explanation of Symbols:
1. An '**' entry in the margin of error column indicates that either no sample observations or too few sample observations were available to compute a standard error and thus the margin of error. A statistical test is not appropriate.
2. An '-' entry in the estimate column indicates that either no sample observations or too few sample observations were available to compute an estimate, or a ratio of medians cannot be calculated because one or both of the median estimates falls in the lowest interval or upper interval of an open-ended distribution.
3. An '-' following a median estimate means the median falls in the lowest interval of an open-ended distribution.
4. An '+' following a median estimate means the median falls in the upper interval of an open-ended distribution.
5. An '***' entry in the margin of error column indicates that the median falls in the lowest interval or upper interval of an open-ended distribution. A statistical test is not appropriate.
6. An '*****' entry in the margin of error column indicates that the estimate is controlled. A statistical test for sampling variability is not appropriate.
7. An 'N' entry in the estimate and margin of error columns indicates that data for this geographic area cannot be displayed because the number of sample cases is too small.
8. An '(X)' means that the estimate is not applicable or not available.

U.S. Census Bureau
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Grayson County, Texas
Selected Housing Characteristics: 2006-2008
Data Set: **2006-2008 American Community Survey 3-Year Estimates**
Survey: **American Community Survey**

NOTE. Although the American Community Survey (ACS) produces population, demographic and housing unit estimates, it is the Census Bureau's Population Estimates Program that produces and disseminates the official estimates of the population for the nation, states, counties, cities and towns and estimates of housing units for states and counties.

For more information on confidentiality protection, sampling error, nonsampling error, and definitions, see Survey Methodology.

Selected Housing Characteristics	Estimate	Margin of Error	Percent	Margin of Error
HOUSING OCCUPANCY				
Total housing units	**51,733**	**+/-569**	**51,733**	**(X)**
Occupied housing units	44,630	+/-1,051	86.3%	+/-1.7
Vacant housing units	7,103	+/-850	13.7%	+/-1.7
Homeowner vacancy rate	3.3	+/-1.1	(X)	(X)
Rental vacancy rate	7.6	+/-3.0	(X)	(X)
UNITS IN STRUCTURE				
Total housing units	**51,733**	**+/-569**	**51,733**	**(X)**
1-unit, detached	39,022	+/-850	75.4%	+/-1.4
1-unit, attached	781	+/-274	1.5%	+/-0.5
2 units	1,611	+/-405	3.1%	+/-0.8
3 or 4 units	995	+/-274	1.9%	+/-0.5
5 to 9 units	1,862	+/-398	3.6%	+/-0.8
10 to 19 units	1,616	+/-392	3.1%	+/-0.7
20 or more units	1,140	+/-285	2.2%	+/-0.6
Mobile home	4,663	+/-594	9.0%	+/-1.2
Boat, RV, van, etc.	43	+/-52	0.1%	+/-0.1
YEAR STRUCTURE BUILT				
Total housing units	**51,733**	**+/-569**	**51,733**	**(X)**
Built 2005 or later	1,134	+/-307	2.2%	+/-0.6
Built 2000 to 2004	4,731	+/-529	9.1%	+/-1.0
Built 1990 to 1999	6,908	+/-734	13.4%	+/-1.4
Built 1980 to 1989	7,843	+/-723	15.2%	+/-1.4
Built 1970 to 1979	9,230	+/-809	17.8%	+/-1.5
Built 1960 to 1969	8,104	+/-858	15.7%	+/-1.6
Built 1950 to 1959	5,400	+/-528	10.4%	+/-1.0
Built 1940 to 1949	2,955	+/-450	5.7%	+/-0.9
Built 1939 or earlier	5,428	+/-714	10.5%	+/-1.4
ROOMS				
Total housing units	**51,733**	**+/-569**	**51,733**	**(X)**
1 room	892	+/-346	1.7%	+/-0.7
2 rooms	1,636	+/-399	3.2%	+/-0.8
3 rooms	3,753	+/-606	7.3%	+/-1.2
4 rooms	8,518	+/-877	16.5%	+/-1.7
5 rooms	14,228	+/-1,003	27.5%	+/-1.9
6 rooms	11,279	+/-847	21.8%	+/-1.7
7 rooms	5,723	+/-595	11.1%	+/-1.1
8 rooms	3,111	+/-479	6.0%	+/-0.9
9 rooms or more	2,593	+/-410	5.0%	+/-0.8
Median rooms	5.3	+/-0.1	(X)	(X)

Selected Housing Characteristics	Estimate	Margin of Error	Percent	Margin of Error
BEDROOMS				
Total housing units	**51,733**	**+/-569**	**51,733**	**(X)**
No bedroom	1,365	+/-391	2.6%	+/-0.8
1 bedroom	4,374	+/-544	8.5%	+/-1.0
2 bedrooms	14,277	+/-1,026	27.6%	+/-1.9
3 bedrooms	24,800	+/-863	47.9%	+/-1.7
4 bedrooms	6,246	+/-527	12.1%	+/-1.0
5 or more bedrooms	671	+/-191	1.3%	+/-0.4
HOUSING TENURE				
Occupied housing units	**44,630**	**+/-1,051**	**44,630**	**(X)**
Owner-occupied	31,741	+/-973	71.1%	+/-1.9
Renter-occupied	12,889	+/-970	28.9%	+/-1.9
Average household size of owner-occupied unit	2.61	+/-0.07	(X)	(X)
Average household size of renter-occupied unit	2.43	+/-0.11	(X)	(X)
YEAR HOUSEHOLDER MOVED INTO UNIT				
Occupied housing units	**44,630**	**+/-1,051**	**44,630**	**(X)**
Moved in 2005 or later	13,237	+/-979	29.7%	+/-1.9
Moved in 2000 to 2004	11,229	+/-859	25.2%	+/-1.8
Moved in 1990 to 1999	10,532	+/-778	23.6%	+/-1.8
Moved in 1980 to 1989	4,770	+/-568	10.7%	+/-1.3
Moved in 1970 to 1979	2,779	+/-406	6.2%	+/-0.9
Moved in 1969 or earlier	2,083	+/-379	4.7%	+/-0.8
VEHICLES AVAILABLE				
Occupied housing units	**44,630**	**+/-1,051**	**44,630**	**(X)**
No vehicles available	2,212	+/-423	5.0%	+/-0.9
1 vehicle available	14,539	+/-1,144	32.6%	+/-2.5
2 vehicles available	18,358	+/-1,165	41.1%	+/-2.5
3 or more vehicles available	9,521	+/-715	21.3%	+/-1.5
HOUSE HEATING FUEL				
Occupied housing units	**44,630**	**+/-1,051**	**44,630**	**(X)**
Utility gas	18,646	+/-933	41.8%	+/-1.9
Bottled, tank, or LP gas	3,892	+/-484	8.7%	+/-1.1
Electricity	21,323	+/-1,166	47.8%	+/-2.2
Fuel oil, kerosene, etc.	91	+/-72	0.2%	+/-0.2
Coal or coke	0	+/-165	0.0%	+/-0.1
Wood	495	+/-232	1.1%	+/-0.5
Solar energy	0	+/-165	0.0%	+/-0.1
Other fuel	109	+/-79	0.2%	+/-0.2
No fuel used	74	+/-59	0.2%	+/-0.1
SELECTED CHARACTERISTICS				
Occupied housing units	**44,630**	**+/-1,051**	**44,630**	**(X)**
Lacking complete plumbing facilities	270	+/-170	0.6%	+/-0.4
Lacking complete kitchen facilities	427	+/-219	1.0%	+/-0.5
No telephone service available	2,473	+/-520	5.5%	+/-1.2
OCCUPANTS PER ROOM				
Occupied housing units	**44,630**	**+/-1,051**	**44,630**	**(X)**
1.00 or less	43,411	+/-1,044	97.3%	+/-0.7
1.01 to 1.50	1,043	+/-300	2.3%	+/-0.7
1.51 or more	176	+/-124	0.4%	+/-0.3
VALUE				
Owner-occupied units	**31,741**	**+/-973**	**31,741**	**(X)**
Less than $50,000	5,624	+/-734	17.7%	+/-2.2
$50,000 to $99,999	11,795	+/-857	37.2%	+/-2.5
$100,000 to $149,999	6,409	+/-604	20.2%	+/-1.8
$150,000 to $199,999	3,828	+/-517	12.1%	+/-1.6
$200,000 to $299,999	2,177	+/-317	6.9%	+/-1.0
$300,000 to $499,999	1,401	+/-324	4.4%	+/-1.0
$500,000 to $999,999	456	+/-215	1.4%	+/-0.7
$1,000,000 or more	51	+/-51	0.2%	+/-0.2
Median (dollars)	93,300	+/-2,774	(X)	(X)

Selected Housing Characteristics	Estimate	Margin of Error	Percent	Margin of Error
MORTGAGE STATUS				
Owner-occupied units	**31,741**	**+/-973**	**31,741**	**(X)**
Housing units with a mortgage	18,540	+/-888	58.4%	+/-2.1
Housing units without a mortgage	13,201	+/-792	41.6%	+/-2.1
SELECTED MONTHLY OWNER COSTS (SMOC)				
Housing units with a mortgage	**18,540**	**+/-888**	**18,540**	**(X)**
Less than $300	0	+/-165	0.0%	+/-0.3
$300 to $499	134	+/-70	0.7%	+/-0.4
$500 to $699	1,630	+/-369	8.8%	+/-2.0
$700 to $999	4,855	+/-552	26.2%	+/-2.6
$1,000 to $1,499	7,218	+/-735	38.9%	+/-3.3
$1,500 to $1,999	3,158	+/-400	17.0%	+/-2.2
$2,000 or more	1,545	+/-332	8.3%	+/-1.8
Median (dollars)	1,142	+/-28	(X)	(X)
Housing units without a mortgage	**13,201**	**+/-792**	**13,201**	**(X)**
Less than $100	108	+/-81	0.8%	+/-0.6
$100 to $199	759	+/-223	5.7%	+/-1.6
$200 to $299	1,973	+/-384	14.9%	+/-2.7
$300 to $399	2,962	+/-451	22.4%	+/-3.1
$400 or more	7,399	+/-570	56.0%	+/-3.4
Median (dollars)	432	+/-16	(X)	(X)
SELECTED MONTHLY OWNER COSTS AS A PERCENTAGE OF HOUSEHOLD INCOME (SMOCAPI)				
Housing units with a mortgage (excluding units where SMOCAPI cannot be computed)	**18,513**	**+/-881**	**18,513**	**(X)**
Less than 20.0 percent	7,088	+/-617	38.3%	+/-3.2
20.0 to 24.9 percent	3,488	+/-539	18.8%	+/-2.7
25.0 to 29.9 percent	2,310	+/-499	12.5%	+/-2.5
30.0 to 34.9 percent	1,717	+/-344	9.3%	+/-1.8
35.0 percent or more	3,910	+/-493	21.1%	+/-2.4
Not computed	27	+/-33	(X)	(X)
Housing unit without a mortgage (excluding units where SMOCAPI cannot be computed)	**13,106**	**+/-782**	**13,106**	**(X)**
Less than 10.0 percent	4,422	+/-544	33.7%	+/-3.5
10.0 to 14.9 percent	2,687	+/-441	20.5%	+/-3.1
15.0 to 19.9 percent	1,922	+/-369	14.7%	+/-2.7
20.0 to 24.9 percent	1,059	+/-293	8.1%	+/-2.1
25.0 to 29.9 percent	786	+/-223	6.0%	+/-1.7
30.0 to 34.9 percent	465	+/-143	3.5%	+/-1.1
35.0 percent or more	1,765	+/-321	13.5%	+/-2.3
Not computed	95	+/-73	(X)	(X)
GROSS RENT				
Occupied units paying rent	**11,882**	**+/-906**	**11,882**	**(X)**
Less than $200	190	+/-112	1.6%	+/-0.9
$200 to $299	468	+/-176	3.9%	+/-1.5
$300 to $499	1,455	+/-335	12.2%	+/-2.9
$500 to $749	4,969	+/-617	41.8%	+/-4.0
$750 to $999	3,104	+/-540	26.1%	+/-3.9
$1,000 to $1,499	1,521	+/-349	12.8%	+/-2.8
$1,500 or more	175	+/-119	1.5%	+/-1.0
Median (dollars)	698	+/-24	(X)	(X)
No rent paid	1,007	+/-290	(X)	(X)
GROSS RENT AS A PERCENTAGE OF HOUSEHOLD INCOME (GRAPI)				
Occupied units paying rent (excluding units where GRAPI cannot be computed)	**11,767**	**+/-904**	**11,767**	**(X)**
Less than 15.0 percent	1,853	+/-513	15.7%	+/-4.0
15.0 to 19.9 percent	1,778	+/-367	15.1%	+/-3.1
20.0 to 24.9 percent	1,660	+/-416	14.1%	+/-3.7
25.0 to 29.9 percent	1,527	+/-470	13.0%	+/-3.7
30.0 to 34.9 percent	938	+/-261	8.0%	+/-2.2
35.0 percent or more	4,011	+/-584	34.1%	+/-4.0

Selected Housing Characteristics	Estimate	Margin of Error	Percent	Margin of Error
Not computed	1,122	+/-294	(X)	(X)

Source: U.S. Census Bureau, 2006-2008 American Community Survey

Data are based on a sample and are subject to sampling variability. The degree of uncertainty for an estimate arising from sampling variability is represented through the use of a margin of error. The value shown here is the 90 percent margin of error. The margin of error can be interpreted roughly as providing a 90 percent probability that the interval defined by the estimate minus the margin of error and the estimate plus the margin of error (the lower and upper confidence bounds) contains the true value. In addition to sampling variability, the ACS estimates are subject to nonsampling error (for a discussion of nonsampling variability, see Accuracy of the Data). The effect of nonsampling error is not represented in these tables.

Notes:
·In prior years, the universe included all owner-occupied units with a mortgage. It is now restricted to include only those units where SMOCAPI is computed, that is, SMOC and household income are valid values.
·In prior years, the universe included all owner-occupied units without a mortgage. It is now restricted to include only those units where SMOCAPI is computed, that is, SMOC and household income are valid values.
·In prior years, the universe included all renter-occupied units. It is now restricted to include only those units where GRAPI is computed, that is, gross rent and household Income are valid values.
·Due to the use of value categories rather than specific amounts collected for each individual housing unit in 2006 and 2007, property value on the 3-year file cannot be inflation adjusted. Any table providing data on property values is reported in current dollars. This is in contrast to the other monetary data on the 3-year file, which are inflated to 2008 dollars.
·The estimate for mortgage status and selected monthly owner costs, median mortgage status and selected monthly owner costs, gross rent, and median gross rent for previous years is adjusted for inflation to the current year.
·The median gross rent excludes no cash renters.
·While the 2008 American Community Survey (ACS) data generally reflect the November 2007 Office of Management and Budget (OMB) definitions of metropolitan and micropolitan statistical areas; in certain instances the names, codes, and boundaries of the principal cities shown in ACS tables may differ from the OMB definitions due to differences in the effective dates of the geographic entities. The 2008 Puerto Rico Community Survey (PRCS) data generally reflect the November 2007 Office of Management and Budget (OMB) definitions of metropolitan and micropolitan statistical areas; in certain instances the names, codes, and boundaries of the principal cities shown in PRCS tables may differ from the OMB definitions due to differences in the effective dates of the geographic entities.
·Estimates of urban and rural population, housing units, and characteristics reflect boundaries of urban areas defined based on Census 2000 data. Boundaries for urban areas have not been updated since Census 2000. As a result, data for urban and rural areas from the ACS do not necessarily reflect the results of ongoing urbanization.

Explanation of Symbols:
1. An '**' entry in the margin of error column indicates that either no sample observations or too few sample observations were available to compute a standard error and thus the margin of error. A statistical test is not appropriate.
2. An '-' entry in the estimate column indicates that either no sample observations or too few sample observations were available to compute an estimate, or a ratio of medians cannot be calculated because one or both of the median estimates falls in the lowest interval or upper interval of an open-ended distribution.
3. An '-' following a median estimate means the median falls in the lowest interval of an open-ended distribution.
4. An '+' following a median estimate means the median falls in the upper interval of an open-ended distribution.
5. An '***' entry in the margin of error column indicates that the median falls in the lowest interval or upper interval of an open-ended distribution. A statistical test is not appropriate.
6. An '*****' entry in the margin of error column indicates that the estimate is controlled. A statistical test for sampling variability is not appropriate.
7. An 'N' entry in the estimate and margin of error columns indicates that data for this geographic area cannot be displayed because the number of sample cases is too small.
8. An '(X)' means that the estimate is not applicable or not available.

U.S. Census Bureau
American FactFinder

Austin County, Texas

Selected Housing Characteristics: 2006-2008
Data Set: **2006-2008 American Community Survey 3-Year Estimates**
Survey: **American Community Survey**

NOTE. Although the American Community Survey (ACS) produces population, demographic and housing unit estimates, it is the Census Bureau's Population Estimates Program that produces and disseminates the official estimates of the population for the nation, states, counties, cities and towns and estimates of housing units for states and counties.

For more information on confidentiality protection, sampling error, nonsampling error, and definitions, see Survey Methodology.

Selected Housing Characteristics	Estimate	Margin of Error	Percent	Margin of Error
HOUSING OCCUPANCY				
Total housing units	**10,822**	**+/-84**	**10,822**	**(X)**
Occupied housing units	9,335	+/-379	86.3%	+/-3.4
Vacant housing units	1,487	+/-366	13.7%	+/-3.4
Homeowner vacancy rate	0.5	+/-0.8	(X)	(X)
Rental vacancy rate	11.4	+/-8.9	(X)	(X)
UNITS IN STRUCTURE				
Total housing units	**10,822**	**+/-84**	**10,822**	**(X)**
1-unit, detached	8,129	+/-354	75.1%	+/-3.1
1-unit, attached	110	+/-91	1.0%	+/-0.8
2 units	103	+/-89	1.0%	+/-0.8
3 or 4 units	330	+/-214	3.0%	+/-2.0
5 to 9 units	194	+/-131	1.8%	+/-1.2
10 to 19 units	134	+/-108	1.2%	+/-1.0
20 or more units	87	+/-93	0.8%	+/-0.9
Mobile home	1,735	+/-354	16.0%	+/-3.3
Boat, RV, van, etc.	0	+/-165	0.0%	+/-0.6
YEAR STRUCTURE BUILT				
Total housing units	**10,822**	**+/-84**	**10,822**	**(X)**
Built 2005 or later	304	+/-157	2.8%	+/-1.5
Built 2000 to 2004	1,008	+/-226	9.3%	+/-2.1
Built 1990 to 1999	2,049	+/-338	18.9%	+/-3.1
Built 1980 to 1989	2,196	+/-396	20.3%	+/-3.6
Built 1970 to 1979	1,515	+/-309	14.0%	+/-2.8
Built 1960 to 1969	831	+/-245	7.7%	+/-2.3
Built 1950 to 1959	1,018	+/-286	9.4%	+/-2.6
Built 1940 to 1949	653	+/-186	6.0%	+/-1.7
Built 1939 or earlier	1,248	+/-351	11.5%	+/-3.2
ROOMS				
Total housing units	**10,822**	**+/-84**	**10,822**	**(X)**
1 room	284	+/-177	2.6%	+/-1.6
2 rooms	38	+/-41	0.4%	+/-0.4
3 rooms	786	+/-251	7.3%	+/-2.3
4 rooms	1,876	+/-373	17.3%	+/-3.5
5 rooms	3,568	+/-492	33.0%	+/-4.5
6 rooms	1,801	+/-327	16.6%	+/-3.0
7 rooms	1,268	+/-316	11.7%	+/-2.9
8 rooms	588	+/-193	5.4%	+/-1.8
9 rooms or more	613	+/-210	5.7%	+/-1.9
Median rooms	5.2	+/-0.1	(X)	(X)

Selected Housing Characteristics	Estimate	Margin of Error	Percent	Margin of Error
BEDROOMS				
Total housing units	**10,822**	**+/-84**	**10,822**	**(X)**
No bedroom	298	+/-181	2.8%	+/-1.7
1 bedroom	776	+/-252	7.2%	+/-2.3
2 bedrooms	2,489	+/-383	23.0%	+/-3.6
3 bedrooms	5,777	+/-510	53.4%	+/-4.6
4 bedrooms	1,389	+/-312	12.8%	+/-2.9
5 or more bedrooms	93	+/-62	0.9%	+/-0.6
HOUSING TENURE				
Occupied housing units	**9,335**	**+/-379**	**9,335**	**(X)**
Owner-occupied	7,427	+/-404	79.6%	+/-3.2
Renter-occupied	1,908	+/-313	20.4%	+/-3.2
Average household size of owner-occupied unit	2.88	+/-0.14	(X)	(X)
Average household size of renter-occupied unit	2.60	+/-0.38	(X)	(X)
YEAR HOUSEHOLDER MOVED INTO UNIT				
Occupied housing units	**9,335**	**+/-379**	**9,335**	**(X)**
Moved in 2005 or later	1,971	+/-365	21.1%	+/-3.7
Moved in 2000 to 2004	2,887	+/-427	30.9%	+/-4.5
Moved in 1990 to 1999	2,370	+/-401	25.4%	+/-4.1
Moved in 1980 to 1989	957	+/-287	10.3%	+/-3.0
Moved in 1970 to 1979	462	+/-189	4.9%	+/-2.0
Moved in 1969 or earlier	688	+/-248	7.4%	+/-2.7
VEHICLES AVAILABLE				
Occupied housing units	**9,335**	**+/-379**	**9,335**	**(X)**
No vehicles available	476	+/-225	5.1%	+/-2.4
1 vehicle available	2,357	+/-423	25.2%	+/-4.3
2 vehicles available	4,463	+/-512	47.8%	+/-5.2
3 or more vehicles available	2,039	+/-338	21.8%	+/-3.6
HOUSE HEATING FUEL				
Occupied housing units	**9,335**	**+/-379**	**9,335**	**(X)**
Utility gas	N	N	N	N
Bottled, tank, or LP gas	N	N	N	N
Electricity	N	N	N	N
Fuel oil, kerosene, etc.	N	N	N	N
Coal or coke	N	N	N	N
Wood	N	N	N	N
Solar energy	N	N	N	N
Other fuel	N	N	N	N
No fuel used	N	N	N	N
SELECTED CHARACTERISTICS				
Occupied housing units	**9,335**	**+/-379**	**9,335**	**(X)**
Lacking complete plumbing facilities	0	+/-165	0.0%	+/-0.7
Lacking complete kitchen facilities	31	+/-37	0.3%	+/-0.4
No telephone service available	208	+/-116	2.2%	+/-1.3
OCCUPANTS PER ROOM				
Occupied housing units	**9,335**	**+/-379**	**9,335**	**(X)**
1.00 or less	8,937	+/-412	95.7%	+/-2.2
1.01 to 1.50	270	+/-143	2.9%	+/-1.5
1.51 or more	128	+/-128	1.4%	+/-1.4
VALUE				
Owner-occupied units	**7,427**	**+/-404**	**7,427**	**(X)**
Less than $50,000	954	+/-283	12.8%	+/-3.7
$50,000 to $99,999	1,621	+/-375	21.8%	+/-4.6
$100,000 to $149,999	1,346	+/-332	18.1%	+/-4.3
$150,000 to $199,999	1,096	+/-261	14.8%	+/-3.6
$200,000 to $299,999	1,114	+/-250	15.0%	+/-3.4
$300,000 to $499,999	791	+/-244	10.7%	+/-3.2
$500,000 to $999,999	302	+/-140	4.1%	+/-1.9
$1,000,000 or more	203	+/-112	2.7%	+/-1.5
Median (dollars)	139,500	+/-19,305	(X)	(X)

Selected Housing Characteristics	Estimate	Margin of Error	Percent	Margin of Error
MORTGAGE STATUS				
Owner-occupied units	**7,427**	**+/-404**	**7,427**	**(X)**
Housing units with a mortgage	3,928	+/-509	52.9%	+/-5.6
Housing units without a mortgage	3,499	+/-421	47.1%	+/-5.6
SELECTED MONTHLY OWNER COSTS (SMOC)				
Housing units with a mortgage	**3,928**	**+/-509**	**3,928**	**(X)**
Less than $300	3	+/-6	0.1%	+/-0.2
$300 to $499	45	+/-48	1.1%	+/-1.2
$500 to $699	558	+/-284	14.2%	+/-6.7
$700 to $999	762	+/-209	19.4%	+/-4.8
$1,000 to $1,499	1,260	+/-276	32.1%	+/-6.3
$1,500 to $1,999	620	+/-216	15.8%	+/-5.3
$2,000 or more	680	+/-204	17.3%	+/-4.8
Median (dollars)	1,273	+/-92	(X)	(X)
Housing units without a mortgage	**3,499**	**+/-421**	**3,499**	**(X)**
Less than $100	52	+/-46	1.5%	+/-1.3
$100 to $199	233	+/-165	6.7%	+/-4.5
$200 to $299	476	+/-190	13.6%	+/-5.3
$300 to $399	903	+/-262	25.8%	+/-5.8
$400 or more	1,835	+/-301	52.4%	+/-7.9
Median (dollars)	415	+/-42	(X)	(X)
SELECTED MONTHLY OWNER COSTS AS A PERCENTAGE OF HOUSEHOLD INCOME (SMOCAPI)				
Housing units with a mortgage (excluding units where SMOCAPI cannot be computed)	**3,928**	**+/-509**	**3,928**	**(X)**
Less than 20.0 percent	1,738	+/-309	44.2%	+/-6.8
20.0 to 24.9 percent	739	+/-246	18.8%	+/-5.5
25.0 to 29.9 percent	613	+/-262	15.6%	+/-6.2
30.0 to 34.9 percent	200	+/-105	5.1%	+/-2.6
35.0 percent or more	638	+/-253	16.2%	+/-6.0
Not computed	0	+/-165	(X)	(X)
Housing unit without a mortgage (excluding units where SMOCAPI cannot be computed)	**3,499**	**+/-421**	**3,499**	**(X)**
Less than 10.0 percent	1,391	+/-299	39.8%	+/-6.9
10.0 to 14.9 percent	666	+/-206	19.0%	+/-5.7
15.0 to 19.9 percent	262	+/-120	7.5%	+/-3.5
20.0 to 24.9 percent	212	+/-127	6.1%	+/-3.5
25.0 to 29.9 percent	271	+/-150	7.7%	+/-4.4
30.0 to 34.9 percent	142	+/-119	4.1%	+/-3.4
35.0 percent or more	555	+/-254	15.9%	+/-6.4
Not computed	0	+/-165	(X)	(X)
GROSS RENT				
Occupied units paying rent	**N**	**N**	**N**	**(X)**
Less than $200	N	N	N	N
$200 to $299	N	N	N	N
$300 to $499	N	N	N	N
$500 to $749	N	N	N	N
$750 to $999	N	N	N	N
$1,000 to $1,499	N	N	N	N
$1,500 or more	N	N	N	N
Median (dollars)	581	+/-41	(X)	(X)
No rent paid	N	N	(X)	(X)
GROSS RENT AS A PERCENTAGE OF HOUSEHOLD INCOME (GRAPI)				
Occupied units paying rent (excluding units where GRAPI cannot be computed)	**1,407**	**+/-318**	**1,407**	**(X)**
Less than 15.0 percent	393	+/-179	27.9%	+/-10.6
15.0 to 19.9 percent	208	+/-150	14.8%	+/-10.1
20.0 to 24.9 percent	190	+/-140	13.5%	+/-9.8
25.0 to 29.9 percent	126	+/-97	9.0%	+/-6.7
30.0 to 34.9 percent	15	+/-22	1.1%	+/-1.6
35.0 percent or more	475	+/-197	33.8%	+/-11.6

Selected Housing Characteristics	Estimate	Margin of Error	Percent	Margin of Error
Not computed	501	+/-219	(X)	(X)

Source: U.S. Census Bureau, 2006-2008 American Community Survey

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Notes:
·In prior years, the universe included all owner-occupied units with a mortgage. It is now restricted to include only those units where SMOCAPI is computed, that is, SMOC and household income are valid values.
·In prior years, the universe included all owner-occupied units without a mortgage. It is now restricted to include only those units where SMOCAPI is computed, that is, SMOC and household income are valid values.
·In prior years, the universe included all renter-occupied units. It is now restricted to include only those units where GRAPI is computed, that is, gross rent and household Income are valid values.
·Due to the use of value categories rather than specific amounts collected for each individual housing unit in 2006 and 2007, property value on the 3-year file cannot be inflation adjusted. Any table providing data on property values is reported in current dollars. This is in contrast to the other monetary data on the 3-year file, which are inflated to 2008 dollars.
·The estimate for mortgage status and selected monthly owner costs, median mortgage status and selected monthly owner costs, gross rent, and median gross rent for previous years is adjusted for inflation to the current year.
·The median gross rent excludes no cash renters.
·While the 2008 American Community Survey (ACS) data generally reflect the November 2007 Office of Management and Budget (OMB) definitions of metropolitan and micropolitan statistical areas; in certain instances the names, codes, and boundaries of the principal cities shown in ACS tables may differ from the OMB definitions due to differences in the effective dates of the geographic entities. The 2008 Puerto Rico Community Survey (PRCS) data generally reflect the November 2007 Office of Management and Budget (OMB) definitions of metropolitan and micropolitan statistical areas; in certain instances the names, codes, and boundaries of the principal cities shown in PRCS tables may differ from the OMB definitions due to differences in the effective dates of the geographic entities.
·Estimates of urban and rural population, housing units, and characteristics reflect boundaries of urban areas defined based on Census 2000 data. Boundaries for urban areas have not been updated since Census 2000. As a result, data for urban and rural areas from the ACS do not necessarily reflect the results of ongoing urbanization.

Explanation of Symbols:
1. An '**' entry in the margin of error column indicates that either no sample observations or too few sample observations were available to compute a standard error and thus the margin of error. A statistical test is not appropriate.
2. An '-' entry in the estimate column indicates that either no sample observations or too few sample observations were available to compute an estimate, or a ratio of medians cannot be calculated because one or both of the median estimates falls in the lowest interval or upper interval of an open-ended distribution.
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6. An '*****' entry in the margin of error column indicates that the estimate is controlled. A statistical test for sampling variability is not appropriate.
7. An 'N' entry in the estimate and margin of error columns indicates that data for this geographic area cannot be displayed because the number of sample cases is too small.
8. An '(X)' means that the estimate is not applicable or not available.

U.S. Census Bureau
American FactFinder

Fort Bend County, Texas

Selected Housing Characteristics: 2006-2008
Data Set: **2006-2008 American Community Survey 3-Year Estimates**
Survey: **American Community Survey**

NOTE. Although the American Community Survey (ACS) produces population, demographic and housing unit estimates, it is the Census Bureau's Population Estimates Program that produces and disseminates the official estimates of the population for the nation, states, counties, cities and towns and estimates of housing units for states and counties.

For more information on confidentiality protection, sampling error, nonsampling error, and definitions, see Survey Methodology.

Selected Housing Characteristics	Estimate	Margin of Error	Percent	Margin of Error
HOUSING OCCUPANCY				
Total housing units	**148,484**	**+/-348**	**148,484**	**(X)**
Occupied housing units	139,275	+/-1,010	93.8%	+/-0.6
Vacant housing units	9,209	+/-895	6.2%	+/-0.6
Homeowner vacancy rate	2.2	+/-0.5	(X)	(X)
Rental vacancy rate	8.7	+/-2.0	(X)	(X)
UNITS IN STRUCTURE				
Total housing units	**148,484**	**+/-348**	**148,484**	**(X)**
1-unit, detached	124,659	+/-1,048	84.0%	+/-0.7
1-unit, attached	2,991	+/-429	2.0%	+/-0.3
2 units	280	+/-149	0.2%	+/-0.1
3 or 4 units	1,086	+/-279	0.7%	+/-0.2
5 to 9 units	2,761	+/-513	1.9%	+/-0.3
10 to 19 units	4,322	+/-595	2.9%	+/-0.4
20 or more units	6,219	+/-641	4.2%	+/-0.4
Mobile home	6,154	+/-631	4.1%	+/-0.4
Boat, RV, van, etc.	12	+/-17	0.0%	+/-0.1
YEAR STRUCTURE BUILT				
Total housing units	**148,484**	**+/-348**	**148,484**	**(X)**
Built 2005 or later	14,890	+/-877	10.0%	+/-0.6
Built 2000 to 2004	34,723	+/-1,263	23.4%	+/-0.9
Built 1990 to 1999	34,992	+/-1,200	23.6%	+/-0.8
Built 1980 to 1989	31,502	+/-1,306	21.2%	+/-0.9
Built 1970 to 1979	22,725	+/-1,040	15.3%	+/-0.7
Built 1960 to 1969	4,651	+/-622	3.1%	+/-0.4
Built 1950 to 1959	2,699	+/-442	1.8%	+/-0.3
Built 1940 to 1949	834	+/-213	0.6%	+/-0.1
Built 1939 or earlier	1,468	+/-320	1.0%	+/-0.2
ROOMS				
Total housing units	**148,484**	**+/-348**	**148,484**	**(X)**
1 room	1,977	+/-437	1.3%	+/-0.3
2 rooms	3,222	+/-601	2.2%	+/-0.4
3 rooms	6,017	+/-605	4.1%	+/-0.4
4 rooms	12,166	+/-1,035	8.2%	+/-0.7
5 rooms	22,061	+/-1,122	14.9%	+/-0.8
6 rooms	26,237	+/-1,056	17.7%	+/-0.7
7 rooms	25,190	+/-1,295	17.0%	+/-0.9
8 rooms	21,081	+/-1,241	14.2%	+/-0.8
9 rooms or more	30,533	+/-1,317	20.6%	+/-0.9
Median rooms	6.6	+/-0.1	(X)	(X)

Selected Housing Characteristics	Estimate	Margin of Error	Percent	Margin of Error
BEDROOMS				
Total housing units	**148,484**	**+/-348**	**148,484**	**(X)**
No bedroom	2,059	+/-451	1.4%	+/-0.3
1 bedroom	8,265	+/-867	5.6%	+/-0.6
2 bedrooms	14,166	+/-1,109	9.5%	+/-0.7
3 bedrooms	59,211	+/-1,660	39.9%	+/-1.1
4 bedrooms	52,327	+/-1,616	35.2%	+/-1.1
5 or more bedrooms	12,456	+/-843	8.4%	+/-0.6
HOUSING TENURE				
Occupied housing units	**139,275**	**+/-1,010**	**139,275**	**(X)**
Owner-occupied	113,924	+/-1,361	81.8%	+/-0.9
Renter-occupied	25,351	+/-1,289	18.2%	+/-0.9
Average household size of owner-occupied unit	3.68	+/-0.03	(X)	(X)
Average household size of renter-occupied unit	3.28	+/-0.13	(X)	(X)
YEAR HOUSEHOLDER MOVED INTO UNIT				
Occupied housing units	**139,275**	**+/-1,010**	**139,275**	**(X)**
Moved in 2005 or later	44,975	+/-1,519	32.3%	+/-1.1
Moved in 2000 to 2004	44,726	+/-1,744	32.1%	+/-1.2
Moved in 1990 to 1999	31,665	+/-1,067	22.7%	+/-0.8
Moved in 1980 to 1989	12,079	+/-915	8.7%	+/-0.6
Moved in 1970 to 1979	4,458	+/-502	3.2%	+/-0.4
Moved in 1969 or earlier	1,372	+/-283	1.0%	+/-0.2
VEHICLES AVAILABLE				
Occupied housing units	**139,275**	**+/-1,010**	**139,275**	**(X)**
No vehicles available	2,830	+/-477	2.0%	+/-0.3
1 vehicle available	33,223	+/-1,342	23.9%	+/-0.9
2 vehicles available	69,456	+/-1,532	49.9%	+/-1.0
3 or more vehicles available	33,766	+/-1,334	24.2%	+/-0.9
HOUSE HEATING FUEL				
Occupied housing units	**139,275**	**+/-1,010**	**139,275**	**(X)**
Utility gas	80,765	+/-1,354	58.0%	+/-1.0
Bottled, tank, or LP gas	4,799	+/-467	3.4%	+/-0.3
Electricity	53,278	+/-1,487	38.3%	+/-1.0
Fuel oil, kerosene, etc.	69	+/-63	0.0%	+/-0.1
Coal or coke	0	+/-165	0.0%	+/-0.1
Wood	46	+/-43	0.0%	+/-0.1
Solar energy	0	+/-165	0.0%	+/-0.1
Other fuel	172	+/-108	0.1%	+/-0.1
No fuel used	146	+/-118	0.1%	+/-0.1
SELECTED CHARACTERISTICS				
Occupied housing units	**139,275**	**+/-1,010**	**139,275**	**(X)**
Lacking complete plumbing facilities	381	+/-157	0.3%	+/-0.1
Lacking complete kitchen facilities	367	+/-208	0.3%	+/-0.1
No telephone service available	8,400	+/-785	6.0%	+/-0.6
OCCUPANTS PER ROOM				
Occupied housing units	**139,275**	**+/-1,010**	**139,275**	**(X)**
1.00 or less	134,882	+/-1,188	96.8%	+/-0.5
1.01 to 1.50	3,560	+/-588	2.6%	+/-0.4
1.51 or more	833	+/-299	0.6%	+/-0.2
VALUE				
Owner-occupied units	**113,924**	**+/-1,361**	**113,924**	**(X)**
Less than $50,000	4,458	+/-485	3.9%	+/-0.4
$50,000 to $99,999	14,324	+/-942	12.6%	+/-0.8
$100,000 to $149,999	25,674	+/-1,283	22.5%	+/-1.0
$150,000 to $199,999	27,309	+/-1,195	24.0%	+/-1.0
$200,000 to $299,999	24,316	+/-1,103	21.3%	+/-1.0
$300,000 to $499,999	14,235	+/-820	12.5%	+/-0.7
$500,000 to $999,999	3,024	+/-391	2.7%	+/-0.3
$1,000,000 or more	584	+/-185	0.5%	+/-0.2
Median (dollars)	169,800	+/-1,984	(X)	(X)

Selected Housing Characteristics	Estimate	Margin of Error	Percent	Margin of Error
MORTGAGE STATUS				
Owner-occupied units	**113,924**	**+/-1,361**	**113,924**	**(X)**
Housing units with a mortgage	90,359	+/-1,522	79.3%	+/-0.9
Housing units without a mortgage	23,565	+/-1,017	20.7%	+/-0.9
SELECTED MONTHLY OWNER COSTS (SMOC)				
Housing units with a mortgage	**90,359**	**+/-1,522**	**90,359**	**(X)**
Less than $300	11	+/-19	0.0%	+/-0.1
$300 to $499	219	+/-146	0.2%	+/-0.2
$500 to $699	934	+/-277	1.0%	+/-0.3
$700 to $999	5,654	+/-665	6.3%	+/-0.7
$1,000 to $1,499	22,542	+/-1,211	24.9%	+/-1.2
$1,500 to $1,999	25,308	+/-1,278	28.0%	+/-1.4
$2,000 or more	35,691	+/-1,354	39.5%	+/-1.5
Median (dollars)	1,805	+/-27	(X)	(X)
Housing units without a mortgage	**23,565**	**+/-1,017**	**23,565**	**(X)**
Less than $100	79	+/-62	0.3%	+/-0.3
$100 to $199	474	+/-160	2.0%	+/-0.7
$200 to $299	1,580	+/-318	6.7%	+/-1.3
$300 to $399	1,961	+/-362	8.3%	+/-1.5
$400 or more	19,471	+/-955	82.6%	+/-1.9
Median (dollars)	658	+/-16	(X)	(X)
SELECTED MONTHLY OWNER COSTS AS A PERCENTAGE OF HOUSEHOLD INCOME (SMOCAPI)				
Housing units with a mortgage (excluding units where SMOCAPI cannot be computed)	**90,035**	**+/-1,516**	**90,035**	**(X)**
Less than 20.0 percent	34,464	+/-1,468	38.3%	+/-1.5
20.0 to 24.9 percent	15,308	+/-1,170	17.0%	+/-1.3
25.0 to 29.9 percent	11,211	+/-869	12.5%	+/-1.0
30.0 to 34.9 percent	7,697	+/-659	8.5%	+/-0.7
35.0 percent or more	21,355	+/-1,305	23.7%	+/-1.3
Not computed	324	+/-171	(X)	(X)
Housing unit without a mortgage (excluding units where SMOCAPI cannot be computed)	**23,210**	**+/-1,027**	**23,210**	**(X)**
Less than 10.0 percent	9,591	+/-721	41.3%	+/-2.4
10.0 to 14.9 percent	4,729	+/-537	20.4%	+/-2.1
15.0 to 19.9 percent	2,538	+/-361	10.9%	+/-1.5
20.0 to 24.9 percent	1,393	+/-292	6.0%	+/-1.3
25.0 to 29.9 percent	1,155	+/-225	5.0%	+/-1.0
30.0 to 34.9 percent	752	+/-203	3.2%	+/-0.9
35.0 percent or more	3,052	+/-467	13.1%	+/-1.9
Not computed	355	+/-198	(X)	(X)
GROSS RENT				
Occupied units paying rent	**23,617**	**+/-1,258**	**23,617**	**(X)**
Less than $200	129	+/-86	0.5%	+/-0.4
$200 to $299	160	+/-124	0.7%	+/-0.5
$300 to $499	592	+/-223	2.5%	+/-0.9
$500 to $749	3,782	+/-558	16.0%	+/-2.3
$750 to $999	6,674	+/-842	28.3%	+/-3.3
$1,000 to $1,499	8,373	+/-845	35.5%	+/-3.0
$1,500 or more	3,907	+/-689	16.5%	+/-2.7
Median (dollars)	1,024	+/-37	(X)	(X)
No rent paid	1,734	+/-348	(X)	(X)
GROSS RENT AS A PERCENTAGE OF HOUSEHOLD INCOME (GRAPI)				
Occupied units paying rent (excluding units where GRAPI cannot be computed)	**23,156**	**+/-1,262**	**23,156**	**(X)**
Less than 15.0 percent	3,341	+/-534	14.4%	+/-2.2
15.0 to 19.9 percent	3,355	+/-541	14.5%	+/-2.3
20.0 to 24.9 percent	3,925	+/-590	17.0%	+/-2.3
25.0 to 29.9 percent	2,218	+/-416	9.6%	+/-1.9
30.0 to 34.9 percent	1,897	+/-417	8.2%	+/-1.8
35.0 percent or more	8,420	+/-898	36.4%	+/-3.0

Selected Housing Characteristics	Estimate	Margin of Error	Percent	Margin of Error
Not computed	2,195	+/-429	(X)	(X)

Source: U.S. Census Bureau, 2006-2008 American Community Survey

Data are based on a sample and are subject to sampling variability. The degree of uncertainty for an estimate arising from sampling variability is represented through the use of a margin of error. The value shown here is the 90 percent margin of error. The margin of error can be interpreted roughly as providing a 90 percent probability that the interval defined by the estimate minus the margin of error and the estimate plus the margin of error (the lower and upper confidence bounds) contains the true value. In addition to sampling variability, the ACS estimates are subject to nonsampling error (for a discussion of nonsampling variability, see Accuracy of the Data). The effect of nonsampling error is not represented in these tables.

Notes:
·In prior years, the universe included all owner-occupied units with a mortgage. It is now restricted to include only those units where SMOCAPI is computed, that is, SMOC and household income are valid values.
·In prior years, the universe included all owner-occupied units without a mortgage. It is now restricted to include only those units where SMOCAPI is computed, that is, SMOC and household income are valid values.
·In prior years, the universe included all renter-occupied units. It is now restricted to include only those units where GRAPI is computed, that is, gross rent and household Income are valid values.
·Due to the use of value categories rather than specific amounts collected for each individual housing unit in 2006 and 2007, property value on the 3-year file cannot be inflation adjusted. Any table providing data on property values is reported in current dollars. This is in contrast to the other monetary data on the 3-year file, which are inflated to 2008 dollars.
·The estimate for mortgage status and selected monthly owner costs, median mortgage status and selected monthly owner costs, gross rent, and median gross rent for previous years is adjusted for inflation to the current year.
·The median gross rent excludes no cash renters.
·While the 2008 American Community Survey (ACS) data generally reflect the November 2007 Office of Management and Budget (OMB) definitions of metropolitan and micropolitan statistical areas; in certain instances the names, codes, and boundaries of the principal cities shown in ACS tables may differ from the OMB definitions due to differences in the effective dates of the geographic entities. The 2008 Puerto Rico Community Survey (PRCS) data generally reflect the November 2007 Office of Management and Budget (OMB) definitions of metropolitan and micropolitan statistical areas; in certain instances the names, codes, and boundaries of the principal cities shown in PRCS tables may differ from the OMB definitions due to differences in the effective dates of the geographic entities.
·Estimates of urban and rural population, housing units, and characteristics reflect boundaries of urban areas defined based on Census 2000 data. Boundaries for urban areas have not been updated since Census 2000. As a result, data for urban and rural areas from the ACS do not necessarily reflect the results of ongoing urbanization.

Explanation of Symbols:
1. An '**' entry in the margin of error column indicates that either no sample observations or too few sample observations were available to compute a standard error and thus the margin of error. A statistical test is not appropriate.
2. An '-' entry in the estimate column indicates that either no sample observations or too few sample observations were available to compute an estimate, or a ratio of medians cannot be calculated because one or both of the median estimates falls in the lowest interval or upper interval of an open-ended distribution.
3. An '-' following a median estimate means the median falls in the lowest interval of an open-ended distribution.
4. An '+' following a median estimate means the median falls in the upper interval of an open-ended distribution.
5. An '***' entry in the margin of error column indicates that the median falls in the lowest interval or upper interval of an open-ended distribution. A statistical test is not appropriate.
6. An '*****' entry in the margin of error column indicates that the estimate is controlled. A statistical test for sampling variability is not appropriate.
7. An 'N' entry in the estimate and margin of error columns indicates that data for this geographic area cannot be displayed because the number of sample cases is too small.
8. An '(X)' means that the estimate is not applicable or not available.

U.S. Census Bureau
American FactFinder

FACT SHEET

Anderson County, Texas

2006-2008 American Community Survey 3-Year Estimates - what's this?
Data Profile Highlights:

NOTE: Although the American Community Survey (ACS) produces population, demographic and housing unit estimates, it is the Census Bureau's Population Estimates Program that produces and disseminates the official estimates of the population for the nation, states, counties, cities and towns and estimates of housing units for states and counties.

Social Characteristics - show more >>	Estimate	Percent	U.S.	Margin of Error	
Average household size	2.88	(X)	2.61	+/-0.09	map
Average family size	3.60	(X)	3.20	+/-0.17	
Population 25 years and over	39,634			+/-583	
High school graduate or higher	(X)	74.3	84.5%	(X)	map
Bachelor's degree or higher	(X)	11.8	27.4%	(X)	map
Civilian veterans (civilian population 18 years and over)	4,975	11.0	10.1%	+/-552	map
With a Disability	(X)	(X)	(X)	(X)	
Foreign born	2,877	5.1	12.5%	+/-637	map
Male, Now married, except separated (population 15 years and over)	11,364	38.5	52.2%	+/-1,138	
Female, Now married, except separated (population 15 years and over)	7,504	42.2	48.2%	+/-664	
Speak a language other than English at home (population 5 years and over)	N	100.0	19.6%	N	map
Household population	44,861			+/-2,390	
Group quarters population	(X)	(X)	(X)	(X)	

Economic Characteristics - show more >>	Estimate	Percent	U.S.	Margin of Error	
In labor force (population 16 years and over)	21,516	46.1	65.2%	+/-1,666	map
Mean travel time to work in minutes (workers 16 years and over)	25.0	(X)	25.3	+/-2.4	map
Median household income (in 2008 inflation-adjusted dollars)	40,875	(X)	52,175	+/-3,341	map
Median family income (in 2008 inflation-adjusted dollars)	50,299	(X)	63,211	+/-4,907	map
Per capita income (in 2008 inflation-adjusted dollars)	17,319	(X)	27,466	+/-1,316	
Families below poverty level	(X)	10.5	9.6%	(X)	
Individuals below poverty level	(X)	13.9	13.2%	(X)	map

Housing Characteristics - show more >>	Estimate	Percent	U.S.	Margin of Error	
Total housing units	19,243			+/-831	
Occupied housing units	15,553	80.8	88.0%	+/-857	
Owner-occupied housing units	11,496	73.9	67.1%	+/-873	
Renter-occupied housing units	4,057	26.1	32.9%	+/-627	
Vacant housing units	3,690	19.2	12.0%	+/-467	
Owner-occupied homes	11,496			+/-873	map
Median value (dollars)	76,900	(X)	192,400	+/-6,447	map
Median of selected monthly owner costs					
With a mortgage (dollars)	1,055	(X)	1,508	+/-52	map
Not mortgaged (dollars)	386	(X)	425	+/-28	

ACS Demographic Estimates - show more >>	Estimate	Percent	U.S.	Margin of Error
Total population	56,636			*****
Male	34,231	60.4	49.3%	+/-238

Female	22,405	39.6	50.7%	+/-238	
Median age (years)	36.9	(X)	36.7	+/-0.8	map
Under 5 years	3,303	5.8	6.9%	+/-53	
18 years and over	45,388	80.1	75.5%	+/-66	
65 years and over	6,647	11.7	12.6%	+/-262	
One race	55,888	98.7	97.8%	+/-339	
White	40,424	71.4	74.3%	+/-661	map
Black or African American	12,707	22.4	12.3%	+/-219	map
American Indian and Alaska Native	349	0.6	0.8%	+/-316	map
Asian	350	0.6	4.4%	+/-88	map
Native Hawaiian and Other Pacific Islander	10	0.0	0.1%	+/-18	map
Some other race	2,048	3.6	5.8%	+/-676	map
Two or more races	748	1.3	2.2%	+/-339	map
Hispanic or Latino (of any race)	7,955	14.0	15.1%	*****	

Source: U.S. Census Bureau, 2006-2008 American Community Survey

Explanation of Symbols:
'***' - The median falls in the lowest interval or upper interval of an open-ended distribution. A statistical test is not appropriate.
'*****' - The estimate is controlled. A statistical test for sampling variability is not appropriate.
'N' - Data for this geographic area cannot be displayed because the number of sample cases is too small.
'(X)' - The value is not applicable or not available.

The letters PDF or symbol indicate a document is in the Portable Document Format (PDF). To view the file you will need the Adobe® Acrobat® Reader, which is available for **free** from the Adobe web site.

U.S. Census Bureau

Population Estimates

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Data Sets

Data sets are provided here to download for analysis in spreadsheet, statistical, or geographic information systems software. Files are in fixed-length ASCII format, each with a separate layout file, and in .csv, a generic spreadsheet format. Files include Federal Information Processing System (FIPS) codes, which uniquely identify geographic areas.

National population datasets

Population, Population change and estimated components of population change: April 1, 2000 to July 1, 2008 (NST-EST2008-alldata)
- File layout (4k)
- CSV file (15k)

Population change: April 1, 2000 to July 1, 2008 (NST-EST2008-popchg2000-2008)
- File layout (4k)
- CSV file (15k)

National estimates by demographic characteristics - single year of age, sex, race, and Hispanic Origin
- Monthly Population Estimates
- Intercensal Estimates (1990-2000)

State population datasets

Population, Population change and estimated components of population change: April 1, 2000 to July 1, 2008 (NST-EST2008-alldata)
- File layout (4k)
- CSV file (15k)

Population change: April 1, 2000 to July 1, 2008 (NST-EST2008-popchg2000-2008)
- File layout (4k)
- CSV file (15k)

State estimates by demographic characteristics - age, sex, race, and Hispanic Origin
- 18+ Population Estimates: July 1, 2008
  - File layout (2k)
  - CSV file (3k)
- State Single Year of Age and Sex Population Estimates: April 1, 2000 to July 1, 2008 - RESIDENT
  - File layout [PDF - 3k]
  - CSV file (903k)
- State Single Year of Age and Sex Population Estimates: April 1, 2000 to July 1, 2008 - CIVILIAN
  - File layout [PDF - 3k]
  - CSV file (903k)
- State by Age, Sex, Race, and Hispanic Origin
  - 6 race groups - 5 race alone groups and one multiple race group
    - File layout [PDF - 1k]
    - All States (4.9M) Help with .csv files
      - Alabama through Idaho (2.4M)
      - Illinois through Missouri (2.3M)
      - Montana through Pennsylvania (2.3M)
      - Rhode Island through Wyoming (2.3M)
  - 5 race groups - 5 race alone or in combination groups
    - File layout [PDF - 1k]

All States (3.6M) Help with .csv files
Alabama through Idaho (2.4M)
Illinois through Missouri (2.3M)
Montana through Pennsylvania (2.3M)
Rhode Island through Wyoming (2.3M)
State by Sex, Race, and Hispanic Origin
6 race groups - 5 race alone groups and one multiple race group
File layout [PDF - 1k]
All States (4.9M) Help with .csv files
Alabama through Idaho (2.4M)
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Montana through Pennsylvania (2.3M)
Rhode Island through Wyoming (2.3M)
5 race groups - 5 race alone or in combination groups
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All States (3.6M) Help with .csv files
Alabama through Idaho (2.4M)
Illinois through Missouri (2.3M)
Montana through Pennsylvania (2.3M)
Rhode Island through Wyoming (2.3M)

Metropolitan, micropolitan, and combined statistical area datasets

Metropolitan and micropolitan statistical area population and estimated components of change: April 1, 2000 to July 1, 2008 (CBSA-EST2008-alldata)
File layout (4k)
CSV file (687k)
Combined statistical area population and estimated components of change: April 1, 2000 to July 1, 2008 (CSA-EST2008-alldata)
File layout (4k)
CSV file (346k)

County population datasets

County population, population change and estimated components of population change: April 1, 2000 to July 1, 2008 (CO-EST2008-alldata)
File layout [PDF - 20k]
CSV file (2,861k)
County population change: April 1, 2000 to July 1, 2008 (CO-EST2008-popchg2000-2008)
File layout [PDF - 16k]
State Datasets
County estimates by demographic characteristics - age, sex, race, and Hispanic Origin
Age, Sex, Race, and Hispanic Origin
File layout [PDF - 3k]
State Datasets
Selected Age Groups and Sex
File layout [PDF - 4k]
State Datasets
Sex, Race, and Hispanic Origin
6 race groups - 5 race alone groups and one multiple race group
File layout [PDF - 2k]
State Datasets
5 race groups - 5 race alone or in combination groups
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State Datasets

Intercensal estimates by demographic characteristics (1990-1999)
File layout (2k)
1990 (22.9M) 1991 (22.9M) 1992 (22.9M) 1993 (22.9M) 1994 (22.9M)
1995 (22.9M) 1996 (22.9M) 1997 (22.9M) 1998 (22.9M) 1999 (22.9M)

Incorporated place and minor civil division population dataset

- File layout (PDF 7k)
  - All States, all geography (7M) **.csv help**
    - Alabama through Missouri (4M)
    - Montana through Wyoming (4M)
  - Individual States
- File layout (PDF 7k)
  - All States, incorporated places only(2M) **.csv help**

Modified Race Data dataset

- Census 2000 Modified Race Data Summary File (64M)
- Modified Race Data Summary File Technical Documentation and ASCII Layout (161k)

Housing Unit datasets

- State-Level Housing Unit Estimates
  - File Layout (PDF 7k)
  - CSV File (5k)
- County-Level Housing Unit Estimates
  - File Layout (PDF 7k)
  - Individual States

Puerto Rico datasets

- Puerto Rico Municipio population change: April 1, 2000 to July 1, 2008 (PRM-EST2008-popchg2000-2008)
  - File layout (PDF 14k)
  - CSV file (24k)
- Puerto Rico Commonwealth - More detailed estimates and projections for Puerto Rico may be found in the Census Bureau's International Data Base.
  - 18+ Population Estimates: July 1, 2008
    - File layout (2k)
    - CSV file (3k)
  - Puerto Rico Single Year of Age and Sex Population Estimates: April 1, 2000 to July 1, 2008
    - File layout (2k)
    - CSV file (903k)
- Puerto Rico Municipio Population Estimates by Age and Sex
  - Five Year Age Groups
    - File layout (4.65k)
    - CSV file (175k)
  - Selected Age Groups
    - File layout (4.65k)

CSV file (175k)

View the schedule of upcoming releases.

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US Army Corps of Engineers

Public Scoping Meeting

Proposed Lower Bois d'Arc Creek Reservoir Environmental Impact Statement Process

Tuesday - Dec 08, 2009
3:00 p.m. to 8:00 p.m.

Fannin County Multi-Purpose Complex
700 FM 87
Bonham, TX

Interested parties are hereby notified that the District Engineer has scheduled a Public Scoping Meeting related to the Clean Water Act Section 404 permit application by North Texas Municipal Water District for the proposed construction of Lower Bois d'Arc Creek.

The application is to construction a dam on Bois d'Arc Creek to impound a water supply reservoir, Lower Bois d'Arc Creek Reservoir. The purpose of the work is to expand water supply resources of the North Texas Municipal Water District.

The Corps intends to prepare an Environmental Impact Statement to assess the direct, indirect, and cumulative environmental, social, and economic effects of issuance of a Department of the Army permit under Section 404 of the Clean Water Act for discharges of dredged and fill material into waters of the United States associated with the construction of the proposed water supply reservoir. In the EIS, the Corps will assess potential impacts associated with a range of alternatives. The preparation of an EIS begins with a scoping process to determine the issues to be addressed in the EIS.

Dec. 8, 2009
3:00 p.m. to 8:00 p.m.
Fannin County Multi-Purpose
700 FM 87
Bonham, Texas
(Complex is about 1.5 miles west of Bonham, north of Highway 56)

Additional Information is Available: Click to view the attachment.

Public Affairs Office, CESWT-PA

Public Notice

U.S. Army Corps
of Engineers
Tulsa District

Reply To:

U.S. Army Corps of Engineers
ATTN: Regulatory Office
1645 South 101st East Avenue
Tulsa, OK 74128-4609

SWT-0-14659
EIS Scoping Meeting
Public Notice No.

November 6, 2009
Public Notice Date

January 9, 2010
Expiration Date

PURPOSE
The purpose of this public notice is to inform you of a proposal for work in which you might be interested and to solicit your comments and information to better enable us to make a reasonable decision on factors affecting the public interest.

SECTION 10
The U.S. Army Corps of Engineers is directed by Congress through Section 10 of the Rivers and Harbors Act of 1899 (33 USC 403) to regulate all work or structures in or affecting the course, condition, or capacity of navigable waters of the United States. The intent of this law is to protect the navigable capacity of waters important to interstate commerce.

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The U.S. Army Corps of Engineers is directed by Congress through Section 404 of the Clean Water Act (33 USC 1344) to regulate the discharges of dredged and fill material into all waters of the United States. These waters include lakes, rivers, streams, mudflats, sandflats, sloughs, wet meadows, natural ponds, and wetlands adjacent to other waters. The intent of the law is to protect these waters from the indiscriminate discharge of material capable of causing pollution and to restore and maintain their chemical, physical, and biological integrity.

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DEPARTMENT OF THE ARMY
CORPS OF ENGINEERS, TULSA DISTRICT
1645 SOUTH 101ST EAST AVENUE
TULSA, OKLAHOMA 74128-4609

November 6, 2009

Application No. SWT-0-14659

PUBLIC NOTICE

U.S. Army Corps of Engineers (Corps), Tulsa District

Announcement of Public Scoping Meeting

Proposed Lower Bois d'Arc Creek Reservoir Environmental Impact Statement (EIS) Process

Interested parties are hereby notified that the District Engineer has scheduled a Public Scoping Meeting related to the Clean Water Act (CWA) Section 404 permit application by North Texas Municipal Water District (NTMWD) for the proposed construction of Lower Bois d'Arc Creek.

The application is to construct a dam on Bois d'Arc Creek to impound a water supply reservoir, Lower Bois d'Arc Creek Reservoir. The purpose of the work is to expand water supply resources of the North Texas Municipal Water District.

The Corps intends to prepare an EIS to assess the direct, indirect, and cumulative environmental, social, and economic effects of issuance of a Department of the Army permit under Section 404 of the CWA for discharges of dredged and fill material into waters of the United States associated with the construction of the proposed water supply reservoir. In the EIS, the Corps will assess potential impacts associated with a range of alternatives. The preparation of an EIS begins with a scoping process to determine the issues to be addressed in the EIS.

Date and Location of Meeting: **December 8, 2009**
3:00pm to 8:00pm
Fannin County Multi-Purpose Complex
700 FM 87
Bonham, Texas
(Complex is about 1.5 miles west of Bonham, north of Hwy 56)

A public notice for the Section 404 CWA permit application was issued on the proposal on October 14, 2008 soliciting comments from Federal, State, and local agencies and officials, interested individuals and the general public. The 30-day comment period was extended by 30 days until December 12, 2008, to afford ample opportunity for public and agency comment on this project. A public Scoping Meeting is being held regarding the proposed action to seek public comments on the proposed project and its potential effects to the human environment. The Corps will be conducting the public scoping meeting, assisted by its Third Party EIS Contractor (Mangi Environmental Group), to describe the project, preliminary alternatives, the National Environmental Policy Act compliance process, and to solicit input on the issues and alternatives to be evaluated and other related matters. Written comments for scoping will be accepted **until January 9, 2010.**

Project Description: The proposed reservoir dam would be located in Bois d'Arc Creek, in the Red River watershed, approximately 15 miles northeast of the town of Bonham, between Farm-to-Market (FM) Road 1396 and FM Road 409, in Fannin County, Texas. The proposed project site consists of 17,068 acres. The purpose of the proposed project is to impound the waters of Bois d'Arc Creek and its tributaries to create a new 16,641-acre water supply reservoir for NTMWD. Lower Bois d'Arc Creek Reservoir Dam would be about 10,400 feet in length and would have a maximum height of about 90 feet. The design top elevation of the embankment would be 553.5 feet mean sea level (' msl) with a conservation pool elevation of 534.0' msl controlled by a service spillway at elevation 534.0' msl with a crest length of 150 feet. Raw water from the reservoir would be transported by 29 miles of 90-inch pipeline to a proposed water treatment plant near the City of Leonard in southwest Fannin County. To allow the NTMWD the ability to treat water from Lower Bois d'Arc Creek Reservoir at its existing facilities in Wylie, Texas, 14 miles of 66-inch pipeline would also extend from the water treatment plant to an outfall on Pilot Grove Creek, a tributary of the East Fork of the Trinity River, to deliver raw water to Lake Lavon, in the Trinity River basin.

Texas Commission on Environmental Quality (TCEQ): Permitting under the CWA Sections 401 and 404 is conducted jointly between the Corps and the TCEQ, with the TCEQ making a State water quality certification decision concurrent with the Corps permit application decision. For the purposes of conducting a TCEQ public meeting, the TCEQ will participate in this EIS Scoping Meeting and will be available for questions and comments regarding the TCEQ's role in reviewing the 404/401 permit application submitted by the NTMWD for the proposed Lower Bois d'Arc Creek Reservoir.

For Additional Information: For further information or questions about the proposed action and EIS, please contact Mr. Andrew Commer, Supervisory Regulatory Project Manager, by letter at Regulatory Office, CESWT-RO, U.S. Army Corps of Engineers, 1645 South 101st East Avenue, Tulsa, Oklahoma, 74128-4609; by telephone at 918-669-7400; by electronic mail *Andrew.Commer@usace.army.mil*. For special needs (visual or hearing impaired, Spanish translator, etc.) requests during scoping meetings, please contact Andrew Commer by November 24, 2009.

David A. Manning
Chief, Regulatory Office

Technologies

Geothermal Basics
FAQs
History
Successes
Enhanced Systems
Hydrothermal Systems
Direct Use
Heat Pumps

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EERE Information Center

Geothermal FAQs

Read the frequently asked questions and their corresponding answers regarding the use of geothermal energy.

What are the benefits of using geothermal energy?

Answer: Several attributes make it a good source of energy.

- First, it's **clean**. Energy can be extracted without burning a fossil fuel such as coal, gas, or oil. Geothermal fields produce only about one-sixth of the carbon dioxide that a relatively clean natural-gas-fueled power plant produces, and very little if any, of the nitrous oxide or sulfur-bearing gases. Binary plants, which are closed cycle operations, release essentially no emissions.
- Geothermal energy is **available 24 hours a day**, 365 days a year. Geothermal power plants have average availabilities of 90% or higher, compared to about 75% for coal plants.
- Geothermal power is homegrown, reducing our dependence on foreign oil.

Why is geothermal energy a renewable resource?

Answer: Because its source is the **almost unlimited amount of heat** generated by the Earth's core. Even in geothermal areas dependent on a reservoir of hot water, the volume taken out can be reinjected, making it a sustainable energy source.

Where is geothermal energy available?

Answer: Hydrothermal resources - reservoirs of steam or hot water - are available primarily in the **western states, Alaska, and Hawaii**. However, Earth energy can be **tapped almost anywhere** with geothermal heat pumps and direct-use applications. Other enormous and world-wide geothermal resources - hot dry rock and magma, for example - are awaiting further technology development.

What are the environmental impacts of using geothermal energy?

Answer: Geothermal technologies offer many environmental advantages over conventional power generation:

- **Emissions are low.** Only excess steam is emitted by geothermal flash plants. No air emissions or liquids are discharged by binary geothermal plants, which are projected to become the dominant technology in the near future.
- Salts and dissolved minerals contained in geothermal fluids are usually reinjected with excess water back into the reservoir at a depth well below groundwater aquifers. This **recycles the geothermal water and replenishes the reservoir**. The City of Santa Rosa, California, pipes the city's **treated wastewater up to The Geysers power plants to be used for reinjection fluid**. This system will prolong the life of the reservoir as it recycles the treated wastewater.
- Some geothermal plants do produce some solid materials, or sludges, that require disposal in approved sites. Some of these **solids are now being extracted for sale** (zinc, silica, and sulfur, for example), making the resource even more valuable and environmentally friendly.

What is the visual impact of geothermal technologies?

Answer: District heating systems and geothermal heat pumps are **easily integrated** into communities with almost no visual impact. Geothermal power plants use **relatively small acreages**, and **don't require storage, transportation, or combustion of fuels**. Either no emissions or just steam are visible. These qualities reduce the overall visual impact of power plants in scenic regions.

Is it possible to deplete geothermal reservoirs?

Answer: The **long-term sustainability** of geothermal energy production has been demonstrated at the Lardarello field in Italy since 1913, at the Wairakei field in New Zealand since 1958, and at The Geysers field in California since 1960. Pressure and production declines have been experienced at some plants, and operators have begun reinjecting water to maintain reservoir pressure. The City of Santa

Rosa, California, pipes its treated wastewater up to The Geysers to be used as reinjection fluid, thereby prolonging the life of the reservoir while recycling the treated wastewater.

How much does geothermal energy cost per kilowatt-hour (kWh)?

Answer: At The Geysers, power is sold at $0.03 to $0.035 per kWh. A power plant **built today** would probably require about **$0.05 per kWh**. Some plants can charge more during peak demand periods.

What does it cost to develop a geothermal power plant?

Answer: Costs of a geothermal plant are **heavily weighted toward early expenses, rather than fuel to keep them running**. Well drilling and pipeline construction occur first, followed by resource analysis of the drilling information. Next is design of the actual plant. Power plant construction is usually completed concurrent with final field development. The initial cost for the field and power plant is around **$2500 per installed kW** in the U.S., probably $3000 to $5000/kWe for a small (<1Mwe) power plant. **Operating and maintenance costs range from $0.01 to $0.03 per kWh**. Most geothermal power plants can run at greater than 90% availability (i.e., producing more than 90% of the time), but running at 97% or 98% can increase maintenance costs. Higher-priced electricity justifies running the plant 98% of the time because the resulting higher maintenance costs are recovered.

What makes a site good for geothermal electric development?

Answer: Hot geothermal fluid with low mineral and gas content, shallow aquifers for producing and reinjecting the fluid, location on private land to simplify permitting, proximity to existing transmission lines or load, and availability of make-up water for evaporative cooling. Geothermal fluid temperature should be at least 300º F, although plants are operating on fluid temperatures as low as 210º F.

How much water does a plant require?

Answer: The flow required depends on the temperature of the fluid, the ambient (sink) characteristics, and the pumping power required to supply and dispose of the fluid. Excluding fluid pumping, a closed-loop binary-cycle geothermal power plant would need 450 to 600 gallons per minute (gpm) to generate 1 MW from a 300° F fluid with an air temperature of 60° F. If the fluid temperature were only 210° F, one would need 1,300 to 1,500 gpm to generate the same amount of power. If an evaporative cooling system were used, 45 to 75 gpm of make-up (clean) cooling water would also be required to generate 1 MW.

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Energy Efficiency
and Renewable Energy

Bringing you a prosperous future where energy is clean, abundant, reliable, and affordable

20% Wind Energy by 2030

Increasing Wind Energy's Contribution to U.S. Electricity Supply

July 2008

GRATEFUL APPRECIATION TO PARTNERS

The U.S. Department of Energy would like to acknowledge the in-depth analysis and extensive research conducted by the National Renewable Energy Laboratory and the major contributions and manuscript reviews by the American Wind Energy Association and many wind industry organizations that contributed to the production of this report. The costs curves for energy supply options and the WinDS modeling assumptions were developed in cooperation with Black & Veatch. The preparation of this technical report was coordinated by Energetics Incorporated of Washington, DC and Renewable Energy Consulting Services, Inc. of Palo Alto, CA. All authors and reviewers who contributed to the preparation of the report are listed in Appendix D.

NOTICE

This report is being disseminated by the Department of Energy. As such, the document was prepared in compliance with Section 515 of the Treasury and General Government Appropriations Act for Fiscal Year 2001 (Public Law 106-554) and information quality guidelines issued by the Department of Energy. Further, this report could be "influential scientific information" as that term is defined in the Office of Management and Budget's Information Quality Bulletin for Peer Review (Bulletin). This report has been peer reviewed pursuant to section II.2 of the Bulletin.

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www.eere.energy.gov/windandhydro
http://www.nrel.gov/docs/fy08osti/41869.pdf

July 2008

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Abbreviations and Acronyms

ACE	area control error
AEO	*Annual Energy Outlook*
AEP	American Electric Power
AGATE	Advanced General Aviation Transport Experiments
AGC	automatic generation control
ALA	American Lung Association
AMA	American Medical Association
API	American Petroleum Institute
APPA	American Public Power Association
ATTU	*Annual Turbine Technology Update*
AWEA	American Wind Energy Association
AWST	AWS Truewind
BACI	before-and-after-control impact
Berkeley Lab	Lawrence Berkeley National Laboratory
BLM	Bureau of Land Management
BPA	Bonneville Power Administration
BSH	Bundesamt für Seeschiffahrt und Hydrographie
BTM	BTM Consult ApS
Btu	British thermal unit
BWEC	Bat and Wind Energy Cooperative
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CAMR	Clean Air Mercury Rule
CapX 2020	Capacity Expansion Plan for 2020
CBO	Congressional Budget Office
CDEAC	Clean and Diversified Energy Advisory Committee
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CESA	Clean Energy States Alliance
CF	capacity factor
CFRP	carbon filament-reinforced plastic
CNV	California/Nevada
CO_2	carbon dioxide
Coal-IGCC	integrated gasification combined cycle coal plants
Coal-new	new pulverized coal plants
COD	commercial operation date
COE	cost of energy
CREZ	Competitive Renewable Energy Zones
CT	combustion turbine
dB	decibels
DEA	Danish Energy Authority
DEIS	draft environmental impact statement
DOD	U.S. Department of Defense
DOE	U.S. Department of Energy
DOI	U.S. Department of Interior
DWT	distributed wind technology

ECAR	East Central Area Reliability Coordinating Agreement
EEI	Edison Electric Institute
EERE	Office of Energy Efficiency and Renewable Energy
EFTA	European Free Trade Agreement
EIA	Energy Information Administration
EIR	environmental impact review
EIS	environmental impact statement
ELCC	effective load-carrying capability
EPA	U.S. Environmental Protection Agency
EPAct	Energy Policy Act
EPC	engineering, procurement, and construction
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
EU	European Union
EUI	Energy Unlimited Inc.
EWEA	European Wind Energy Association
FAA	Federal Aviation Administration
FACTS	flexible AC transmission system
FEIR	final environmental impact report
FERC	Federal Energy Regulatory Commission
FL	Florida
FRCC	Florida Reliability Coordinating Council
FTE	full-time equivalent
GaAs	gallium arsenide
Gas-CC	combined cycle natural gas plants
Gas-CT	gas combustion turbine
GE	General Electric International
GHG	greenhouse gas
GIS	geographic information system
GRP	glass fiber-reinforced-plastic
GS3C	Grassland/Shrub-Steppe Species Collaborative
GVW	gross vehicle weight
GW	gigawatt
GWh	gigawatt-hour
Hg	mercury
HSIL	high-surge impedance-loading (transmission line)
HVDC	high-voltage direct current
Hz	hertz
IEA	International Energy Agency
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IGCC	integrated gasification combined cycle
IOU	investor-owned utility
IPCC	Intergovernmental Panel on Climate Change
IRP	integrated resource planning
ISET	Institute for Solar Energy Technology (Institut für Solare Energieversorgungstechnik)
ISO	independent system operator

ISO-NE	ISO New England
ITC	investment tax credit
JEDI	Jobs and Economic Development Impact (model)
kg	kilogram
km^2	square kilometers
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
lb	pound
LC	levelized cost
LDC	load duration curve
LIDAR	light detection and ranging
LLC	Limited Liability Company
LNG	liquefied natural gas
LOLP	loss of load probability
m	meter
m^2	square meter
MAAC	Mid-Atlantic Area Council
MACRS	Modified Accelerated Cost Recovery System
MAIN	Mid-American Interconnected Network
MAPP	Mid-Continent Area Power Pool
Midwest ISO	Midwest Independent System Operator
MMBtu	million British thermal units
MMS	Minerals Management Service
MMTCE	million metric tons of carbon equivalent
MNDOC	Minnesota Department of Commerce
MOU	Memorandum of Understanding
MRO	Midwest Reliability Organization
MTEP	MISO Transmission Expansion Plan
MVA	megavolt amperes
MW	megawatt
MWh	megawatt-hour
MW-mile	megawatt-mile
NAICS	North American Industrial Classification System
NAS	National Academy of Sciences
NCAR	National Center for Atmospheric Research
NCEP	National Commission on Energy Policy
NE	New England
NEMS	National Energy Modeling System
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NESCAUM	Northeast States for Coordinated Air Use Management
NGOs	nongovernmental organizations
nm	nautical mile
NOAA	National Oceanic and Atmospheric Administration
NOI	notice of intent
NOx	nitrogen oxides
NPCC	Northeast Power Coordinating Council
NPV	net present value

NRC	National Research Council
NRECA	National Rural Electric Cooperative Association
NREL	National Renewable Energy Laboratory
NSTC	National Science and Technology Council
NWCC	National Wind Coordinating Collaborative
NWF	National Wildlife Federation
NWS	National Weather Service
NY	New York
NYISO	New York Independent System Operator
NYSERDA	New York State Energy Research and Development Authority
O_3	ozone
O&M	operations and maintenance
OE	Office of Electricity Delivery and Energy Reliability
OCS	Outer Continental Shelf
OMB	Office of Management and Budget
PBF	Public Benefits Fund
PGE	Portland General Electric
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PMA	Power Marketing Administration
PNM	Public Service Company of New Mexico
POI	point of interconnection
PPA	power purchase agreement
PSE	Puget Sound Energy
PTC	production tax credit
PUC	Public Utility Commission
PURPA	Public Utility Regulatory Policies Act
QF	qualifying or qualified facility
R&D	research and development
RMA	Rocky Mountain Area
RD&D	research, development & demonstration
REC	renewable energy credit
REPI	Renewable Energy Production Incentive
REPP	Renewable Energy Policy Project
RFC	ReliabilityFirst Corporation
RGGI	Regional Greenhouse Gas Initiative
RMATS	Rocky Mountain Area Transmission Study
RPS	Renewable Portfolio Standards
RTO	Regional Transmission Organization
s	second
Sandia	Sandia National Laboratories
SCADA	supervisory control and data acquisition
SEAC	Strategic Energy Analysis Center
SEPA	Southeastern Power Administration
SERC	Southeastern Electric Reliability Council
SF_6	sulfur hexafluoride (one of six greenhouse gases identified in the Kyoto Protocol)
SiC	silicon carbide
SO_2	sulfur dioxide
SODAR	sonic detection and ranging

SO_x	sulfur oxides
SPP	Southwest Power Pool
ST	steam turbine
Std. Dev.	standard deviation
SWPA	Southwestern Power Administration
TRE	Texas Regional Entity
TVA	Tennessee Valley Authority
TWh	terawatt-hours
UCTE	Union for the Co-ordination of Transmission of Electricity
UKERC	UK Energy Research Centre
USACE	U.S. Army Corps of Engineers
USCAP	U.S. Climate Action Partnership
USDA	U.S. Department of Agriculture
USFS	U.S. Department of Agriculture Forest Service
USFWS	U.S. Fish & Wildlife Service
USGS	U.S. Geological Survey
UWIG	Utility Wind Integration Group
V	volt
VAR	volt-ampere-reactive
W	watt
WEST	Western EcoSystems Technology
Western	Western Area Power Administration (formerly WAPA)
WCI	Western Climate Initiative
WECC	Western Electricity Coordinating Council
WGA	Western Governors' Association
Wh	watt-hour
WinDS	Wind Energy Deployment System Model
WindPACT	Wind Partnerships for Advanced Component Technology
WPA	Wind Powering America
WRA	Western Resource Advocates
WRCAI	Western Regional Climate Action Initiative
WWG	Wildlife Workgroup

Chapter 1. Executive Summary & Overview

1.1 INTRODUCTION AND COLLABORATIVE APPROACH

Energy prices, supply uncertainties, and environmental concerns are driving the United States to rethink its energy mix and develop diverse sources of clean, renewable energy. The nation is working toward generating more energy from domestic resources—energy that can be cost-effective and replaced or "renewed" without contributing to climate change or major adverse environmental impacts.

In 2006, President Bush emphasized the nation's need for greater energy efficiency and a more diversified energy portfolio. This led to a collaborative effort to explore a modeled energy scenario in which wind provides 20% of U.S. electricity by 2030. Members of this 20% Wind collaborative (see 20% Wind Scenario sidebar) produced this report to start the discussion about issues, costs, and potential outcomes associated with the 20% Wind Scenario. A 20% Wind Scenario in 2030, while ambitious, could be feasible if the significant challenges identified in this report are overcome.

> ### 20% Wind Scenario: Wind Energy Provides 20% of U.S. Electricity Needs by 2030
>
> #### Key Issues to Examine:
>
> - Does the nation have sufficient wind energy resources?
> - What are the wind technology requirements?
> - Does sufficient manufacturing capability exist?
> - What are some of the key impacts?
> - Can the electric network accommodate 20% wind?
> - What are the environmental impacts?
> - Is the scenario feasible?
>
> #### Assessment Participants:
>
> - U.S. Department of Energy (DOE)
>   - Office of Energy Efficiency and Renewable Energy (EERE), Office of Electricity Delivery and Energy Reliability (OE), and Power Marketing Administrations (PMAs)
>   - National Renewable Energy Laboratory (NREL)
>   - Lawrence Berkeley National Laboratory (Berkeley Lab)
>   - Sandia National Laboratories (SNL)
> - Black & Veatch engineering and consulting firm
> - American Wind Energy Association (AWEA)
>   - Leading wind manufacturers and suppliers
>   - Developers and electric utilities
>   - Others in the wind industry

This report was prepared by DOE in a joint effort with industry, government, and the nation's national laboratories (primarily the National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory). The report considers some associated challenges, estimates the impacts, and discusses specific needs and outcomes in the areas of technology, manufacturing and employment, transmission and grid integration, markets, siting strategies, and potential environmental effects associated with a 20% Wind Scenario.

In its Annual Energy Outlook 2007, the U.S. Energy Information Administration (EIA) estimates that U.S. electricity demand will grow by 39% from 2005 to 2030, reaching 5.8 billion megawatt-hours (MWh) by 2030. To meet 20% of that demand, U.S. wind power capacity would have to reach more than 300 gigawatts (GW) or more than 300,000 megawatts (MW). This growth represents an increase of more than 290 GW within 23 years.[1]

The data analysis and model runs for this report were concluded in mid-2007. All data and information in the report are based on wind data available through the end of 2006. At that time, the U.S. wind power fleet numbered 11.6 GW and spanned 34 states. In 2007, 5,244 MW of new wind generation were installed.[2] With these additions, American wind plants are expected to generate an estimated 48 billion kilowatt-hours (kWh) of wind energy in 2008, more than 1% of U.S. electricity supply. This capacity addition of 5,244 MW in 2007 exceeds the more conservative growth trajectory developed for the 20% Wind Scenario of about 4,000 MW/year in 2007 and 2008. The wind industry is on track to grow to a size capable of installing 16,000 MW/year, consistent with the latter years in the 20% Wind Scenario, more quickly than the trajectory used for this analysis.

1.1.1 Scope

This report examines some of the costs, challenges, and key impacts of generating 20% of the nation's electricity from wind energy in 2030. Specifically, it investigates requirements and outcomes in the areas of technology, manufacturing, transmission and integration, markets, environment, and siting.

The modeling done for this report estimates that wind power installations with capacities of more than 300 gigawatts (GW) would be needed for the 20% Wind Scenario. Increasing U.S. wind power to this level from 11.6 GW in 2006 would require significant changes in transmission, manufacturing, and markets. This report presents an analysis of one specific scenario for reaching the 20% level and contrasts it to a scenario of no wind growth beyond the level reached in 2006. Major assumptions in the analysis have been highlighted throughout the document and have been summarized in the appendices. These assumptions may be considered optimistic. In this report, no sensitivity analyses have been done to estimate the impact that changes in the assumptions would have on the information presented here. As summarized at the end of this chapter, the analysis provides an overview of some potential impacts of these two scenarios by 2030. This report does not compare the Wind Scenario to other energy portfolio options, nor does it outline an action plan.

To successfully address energy security and environmental issues, the nation needs to pursue a portfolio of energy options. None of these options by itself can fully address these issues; there is no "silver bullet." This technical report examines one potential scenario in which wind power serves as a significant element in the portfolio. However, the 20% Wind Scenario is not a prediction of the future. Instead, it paints a picture of what a particular 20% Wind Scenario could mean for the nation.

---

[1] AEO data from 2007 were used in this report. AEO released new data in March of 2008, which were not incorporated into this report. While the new EIA data could change specific numbers in the report, it would not change the overall message of the report.

[2] According to AWEA's 2007 Market Report of January 2008, the U.S. wind energy industry installed 5,244 MW in 2007, expanding the nation's total wind power generating capacity by 45% in a single calendar year and more than doubling the 2006 installation of 2,454 MW. Government sources for validation of 2007 installations were not available at the time this report was written.

1.1.2 Contributors

Report contributors include a broad cross section of key stakeholders, including leaders from the nation's utility sector, environmental communities, wildlife advocacy groups, energy industries, the government and policy sectors, investors, and public and private businesses. In all, the report reflects input from more than 50 key energy stakeholder organizations and corporations. Appendix D contains a list of contributors. Research and modeling was conducted by experts within the electric industry, government, and other organizations.

This report is not an authoritative expression of policy perspectives or opinions held by representatives of DOE.

1.1.3 Assumptions and Process

To establish the groundwork for this report, the engineering company Black & Veatch (Overland Park, Kansas) analyzed the market potential for significant wind energy growth, quantified the potential U.S. wind supply, and developed cost supply curves for the wind resource. In consultation with DOE, NREL, AWEA, and wind industry partners, future wind energy cost and performance projections were developed. Similar projections for conventional generation technologies were developed based on Black & Veatch experience with power plant design and construction (Black & Veatch 2007).

To identify a range of challenges, possible solutions, and key impacts of providing 20% of the nation's electricity from wind, the stakeholders in the 20% Wind Scenario effort convened expert task forces to examine specific areas

Wind Energy Deployment System Model Assumptions (See Appendices A and B)

- The assumptions used for the WinDS model were obtained from a number of sources, including technical experts (see Appendix D), the WinDS base case (Denholm and Short 2006), AEO 2007 (EIA 2007), and a study performed by Black & Veatch (2007). These assumptions include projections of future costs and performance for all generation technologies, transmission system expansion costs, wind resources as a function of geographic location within the continental United States, and projected growth rates for wind generation.
- Wind energy generation is prescribed annually on a national level in order to reach 20% wind energy by 2030:
  - A stable policy environment supports accelerated wind deployment.
  - Balance of generation is economically optimized with no policy changes from those in place today (e.g., no production tax credit [PTC] beyond 12/31/08).
  - Technology cost and performance assumptions as well as electric grid expansion and operation assumptions that affect the direct electric system cost.
- Land-based and offshore wind energy technology cost reductions and performance improvements are expected by 2030 (see tables A-1, B-10, and B-11). Assumes that capital costs would be reduced by 10% over the next two decades and capacity factors would be increased by about 15% (corresponding to a 15% increase in annual energy generation by a wind plant)
- Future environmental study and permit requirements do not add significant costs to wind technology.
- Fossil fuel technology costs and performance are generally flat between 2005 and 2030 (see tables A-1 and B-13).
- Nuclear technology cost reductions are expected by 2030 (see tables A-1 and B-13).
- Reserve and capacity margins are calculated at the North American Electric Reliability Corporation (NERC) region level, and new transmission capacity is added as needed (see sections A.2.2 and B.3).
- Wind resource as a function of geographic location from various sources (see Table B-8).
- Projected electricity demand, financing assumptions, and fuel prices are based on *Annual Energy Outlook* (EIA 2007; see sections B.1, B.2, and B.4.2).
- Cost of new transmission is generally split between the originating project, be it wind or conventional generation, and the ratepayers within the region.
- Ten percent of existing grid capacity is available for wind energy.
- Existing long-term power purchase agreements are not implemented in WinDS. The model assumes that local load is met by the generation technologies in a given region.
- Assumes that the contributions to U.S. electricity supplies from other renewable sources of energy would remain at 2006 levels in both scenarios.

critical to this endeavor: Technology and Applications, Manufacturing and Materials, Environmental and Siting Impacts, Electricity Markets, Transmission and Integration, and Supporting Analysis. These teams conducted in-depth analyses of potential impacts, using related studies and various analytic tools to examine the benefits and costs. (See Appendix D for the task force participants.)

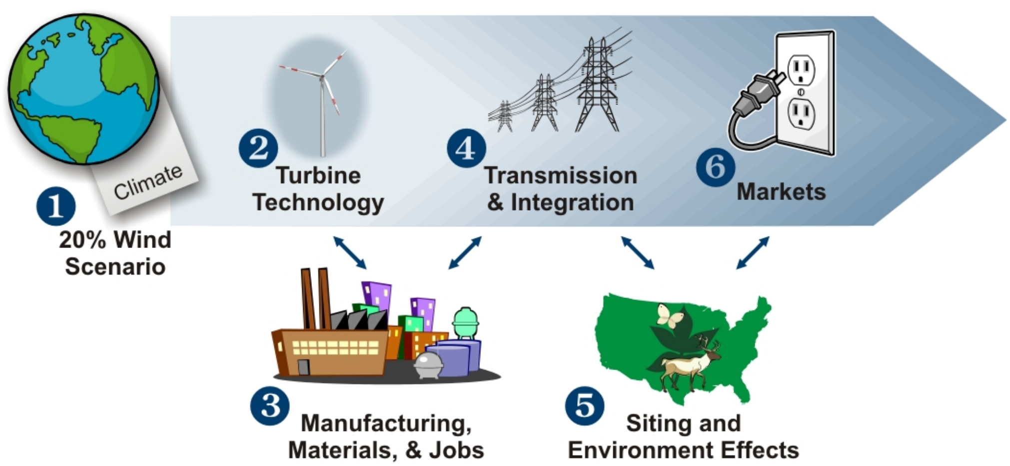
NREL's Wind Deployment System (WinDS) model[3] was employed to create a scenario that paints a "picture" of this level of wind energy generation and evaluates some impacts associated with wind. Assumptions about the future of the U.S. electric generation and transmission sector were developed in consultation with the task forces and other parties. Some assumptions in this analysis could be considered optimistic. Examples of assumptions used in this analysis are listed in the "Wind Energy Deployment System Model Assumptions" text box and are presented in detail in Appendices A and B. For comparison, the modeling team contrasted the 20% Wind Scenario impacts to a reference case characterized by no growth in U.S. wind capacity or other renewable energy sources after 2006.

In the course of the 20% Wind Scenario process, two workshops were held to define and refine the work plan, present and discuss preliminary results, and obtain relevant input from key stakeholders external to the report preparation effort.

1.1.4 REPORT STRUCTURE

The 20% Wind Scenario in 2030 would require improved turbine technology to generate wind power, significant changes in transmission systems to deliver it through the electric grid, and large expanded markets to purchase and use it. In turn, these essential changes in the power generation and delivery process would involve supporting changes and capabilities in manufacturing, policy development, and environmental regulation. As shown in Figure 1-1, the chapters of this report address some of the requirements and impacts in each of these areas. Detailed discussions of the modeling process, assumptions, and results can be found in Appendices A through C.

Figure 1-1. Report chapters



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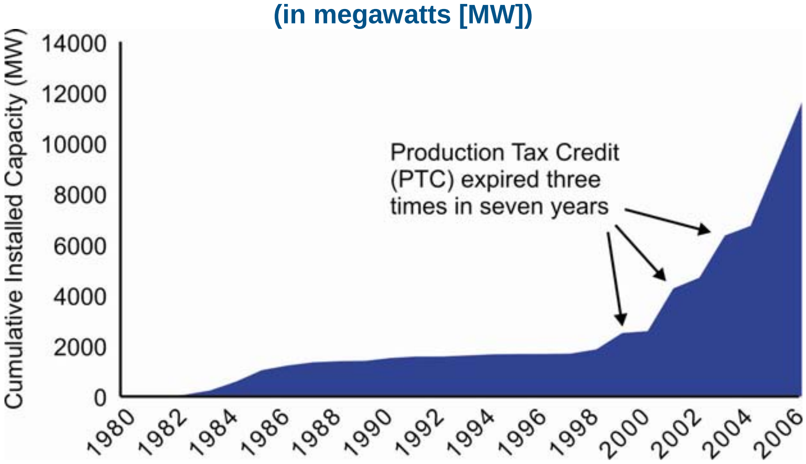
[3] The model, developed by NREL's Strategic Energy Analysis Center (SEAC), is designed to address the principal market issues related to the penetration of wind energy technologies into the electric sector. For additional information and documentation, see text box entitled "Wind Energy Deployment System Model Assumptions," Appendices A and B, and http://www.nrel.gov/analysis/winds/.

1.1.5 SETTING THE CONTEXT: TODAY'S U.S. WIND INDUSTRY

After experiencing strong growth in the mid-1980s, the U.S. wind industry hit a plateau during the electricity restructuring period in the 1990s and then regained momentum in 1999. Industry growth has since responded positively to policy incentives when they are in effect (see Figure 1-2). Today, the U.S. wind industry is growing rapidly, driven by sustained production tax credits (PTCs), rising concerns about climate change, and renewable portfolio standards (RPS) or goals in roughly 50% of the states.

Figure 1-2. Cumulative U.S. wind capacity, by year (in megawatts [MW])



U.S. turbine technology has advanced steadily to offer improved performance, and these efforts are expected to continue (see "Initiatives to Improve Wind Turbine Performance" sidebar). In 2006 alone, average turbine size increased by more than 11% over the 2005 level to an average size of 1.6 MW. In addition, average capacity factors have improved 11% over the past two years. To meet the growing demand for wind energy, U.S. manufacturers have expanded their capacity to produce and assemble the essential components. Despite this growth, U.S. components continue to represent a relatively small share of total turbine and tower materials, and U.S. manufacturers are struggling to keep pace with rising demand (Wiser & Bolinger 2007).

Initiatives to Improve Wind Turbine Performance

Avoid problems before installation

- Improve reliability of turbines and components
- Full-scale testing prior to commercial introduction
- Development of appropriate design criteria, specifications, and standards
- Validation of design tools

Monitor performance

- Monitor and evaluate turbine and wind-plant performance
- Performance tracking by independent parties
- Early identification of problems

Rapid deployment of problem resolution

- Develop and communicate problem solutions
- Focused activities with stakeholders to address critical issues (e.g., Gearbox Reliability Collaborative)

1

In 2005 and 2006, the United States led the world in new wind installations. By early 2007, global wind power capacity exceeded 74 GW, and U.S. wind power capacity totaled 11.6 GW. This domestic wind power has been installed across 35 states and delivers roughly 0.8% of the electricity consumed in the nation (Wiser and Bolinger 2007).

A Brief History of the U.S. Wind Industry

The U.S. wind industry got its start in California during the 1970s, when the oil shortage increased the price of electricity generated from oil. The California wind industry benefited from federal and state ITCs as well as state-mandated standard utility contracts that guaranteed a satisfactory market price for wind power. By 1986, California had installed more than 1.2 GW of wind power, representing nearly 90% of global installations at that time.

Expiration of the federal ITC in 1985 and the California incentive in 1986 brought the growth of the U.S. wind energy industry to an abrupt halt in the mid-1980s. Europe took the lead in wind energy, propelled by aggressive renewable energy policies enacted between 1974 and 1985. As the global industry continued to grow into the 1990s, technological advances led to significant increases in turbine power and productivity. Turbines installed in 1998 had an average capacity 7 to 10 times greater than that of the 1980s turbines, and the price of wind-generated electricity dropped by nearly 80% (AWEA 2007). By 2000, Europe had more than 12,000 MW of installed wind power, versus only 2,500 MW in the United States, and Germany became the new international leader.

With low natural gas prices and U.S. utilities preoccupied by industry restructuring during the 1990s, the federal production tax credit (PTC) enacted in 1992 (as part of the Energy Policy Act [EPAct]) did little to foster new wind installations until just before its expiration in June 1999. Nearly 700 MW of new wind generation were installed in the last year before the credit expired—more than in any previous 12-month period since 1985. After the PTC expired in 1999, it was extended for two brief periods, ending in 2003. It was then reinstated in late 2004. Although this intermittent policy support led to sporadic growth, business inefficiencies inherent in serving this choppy market inhibited investment and restrained market growth.

Energy Policy Act of 1992

The PTC gave power producers 1.5 cents (increased annually with inflation) for every kilowatt-hour (kWh) of electricity produced from wind during the first 10 years of operation.

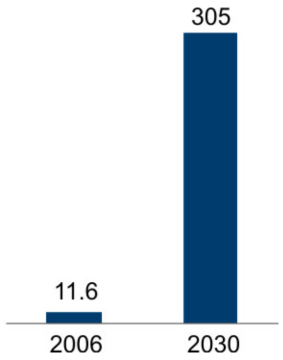
To promote renewable energy systems, many states began requiring electricity suppliers to obtain a small percentage of their supply from renewable energy sources, with percentages typically increasing over time. With Iowa and Texas leading the way, more than 20 states have followed suit with RPSs, creating an environment for stable growth.

After a decade of trailing Germany and Spain, the United States reestablished itself as the world leader in new wind energy in 2005. This resurgence is attributed to increasingly supportive policies, growing interest in renewable energy, and continued improvements in wind technology and performance. The United States retained its leadership of wind development in 2006 and, because of its very large wind resources, is likely to remain a major force in the highly competitive wind markets of the future.

1.2 Scenario Description

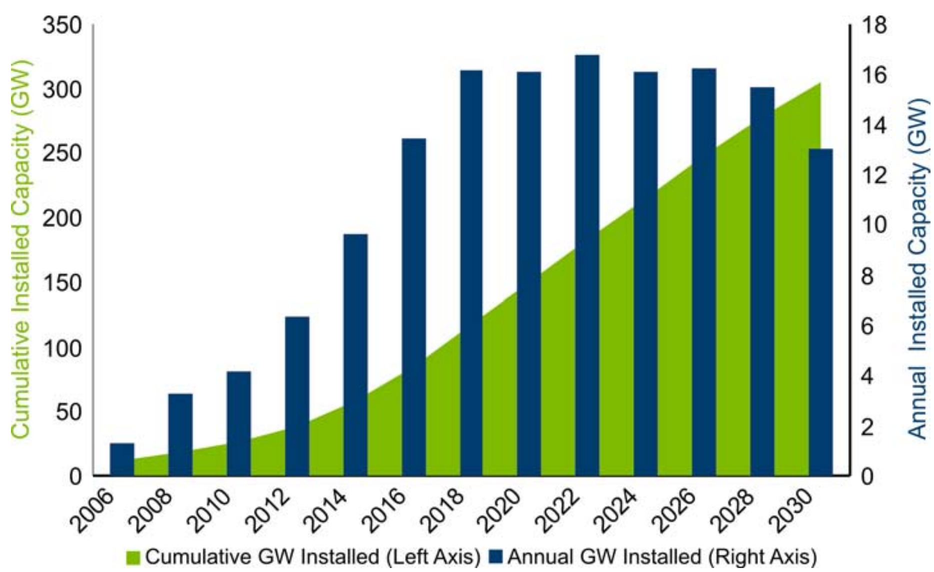
The 20% Wind Scenario presented here would require U.S. wind power capacity to grow from 11.6 GW in 2006 to more than 300 GW over the next 23 years (see Figure 1-3). This ambitious growth could be achieved in many different ways, with varying challenges, impacts, and levels of success. The 20% Wind Scenario would require an installation rate of 16 GW per year after 2018 (see Figure 1-4). This report examines one particular scenario for achieving this dramatic growth and contrasts it to another scenario that—for analytic simplicity—assumes no wind growth after 2006. The authors recognize that U.S. wind capacity is currently growing rapidly (although from a very small base) and that wind energy technology will be a part of any future electricity generation scenario for the United States. At the same time, a great deal of uncertainty remains about the level of contribution that wind could or is likely to make. In the 2007 *Annual Energy Outlook* (EIA 2007), an additional 7 GW beyond the 2006 installed capacity of 11.6 GW is forecast by 2030.[4] Other organizations are projecting higher capacity additions, and it would be difficult to develop a "most likely" forecast given today's uncertainties. The analysis presented here sidesteps these uncertainties and contrasts some of the challenges and impacts of producing 20% of the nation's electricity from wind with a scenario in which no additional wind is added after 2006. This results in an estimate, expressed in terms of parameters, of the impacts associated with increased reliance on wind energy generation under given assumptions. The analysis was also simplified by assuming that the contributions to U.S. electricity supplies from other renewable sources of energy would remain at 2006 levels in both scenarios (see Figure A-6 for resource mix).

Figure 1-3. Required growth in U.S. capacity (GW) to implement the 20% Wind Scenario



The 20% Wind Scenario has been carefully defined to provide a base of

Figure 1-4. Annual and cumulative wind installations by 2030



[4] AEO data from 2007 were used in this report. AEO released new data in March 2008, which were not incorporated into this report. While new EIA data could change specific numbers in this report, it would not change the overall message of the report.

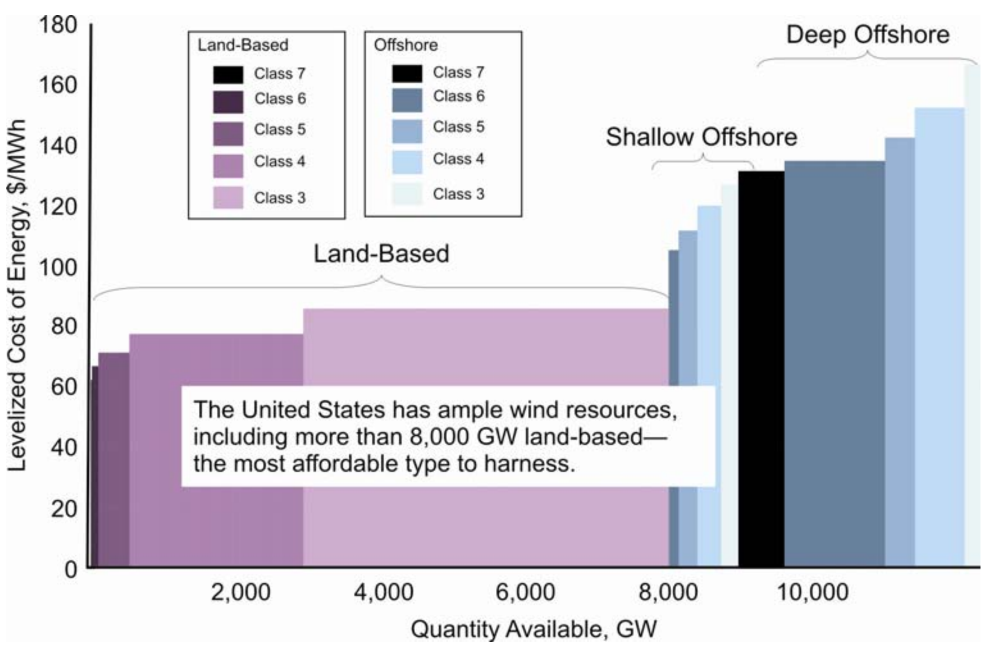
common assumptions for detailed analysis of all impact areas. Broadly stated, this 20% scenario is designed to consider incremental costs while recognizing realistic constraints and considerations (see the “Considerations in the 20% Wind Scenario” sidebar in Appendix A). Specifically, the scenario describes the mix of wind resources that would need to be captured, the geographic distribution of wind power installations, estimated land needs, the required utility and transmission infrastructure, manufacturing requirements, and the pace of growth that would be necessary.

1.2.1 Wind Geography

The United States possesses abundant wind resources. As shown in Figure 1-5, current “bus-bar” energy costs for wind (based on costs of the wind plant only, excluding transmission and integration costs and the PTC) vary by type of location (land-based or offshore) and by class of wind power density (higher classes offer greater productivity). Transmission and integration will add additional costs, which are discussed in Chapter 4. The nation has more than 8,000 GW of available land-based wind resources (Black & Veatch 2007) that industry estimates can be captured economically. NREL periodically classifies wind resources by wind speed, which forms the basis of the Black & Veatch study. See Appendix B for further details.

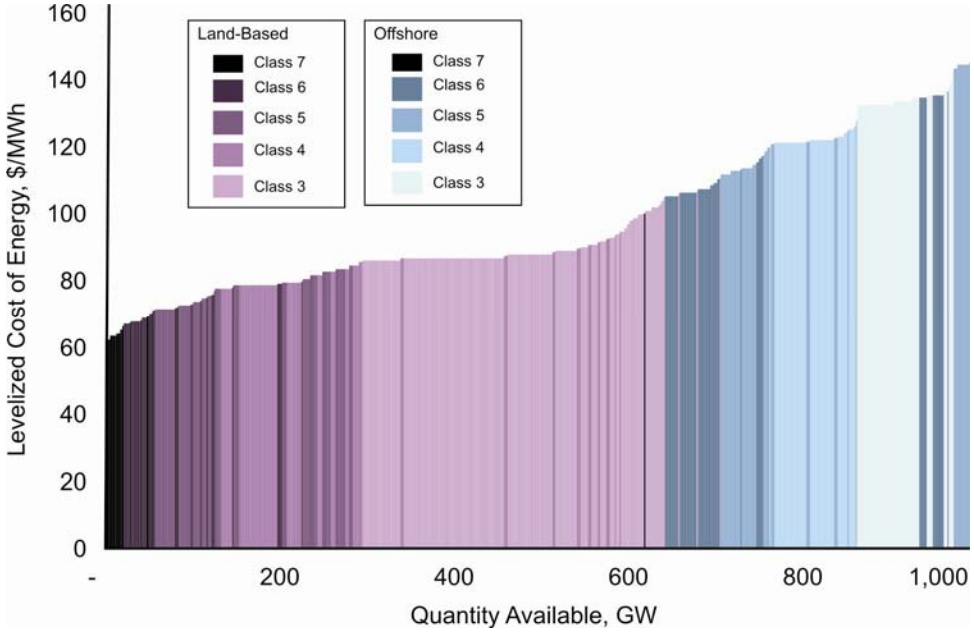
Electricity must be transmitted from where it is generated to areas of high electricity demand, using the existing transmission system or new transmission lines where necessary. As shown in Figure 1-6, the delivered cost of wind power increases when costs associated with connecting to the existing electric grid are included. The assumptions used in this report are different than EIA’s assumptions and are documented in Appendices A and B. The cost and performance assumptions of the 20% Wind Scenario are based on real market data from 2007. Cost and performance for all technologies either decrease or remain flat over time. The data suggest that as

Figure 1-5. Supply curve for wind energy—current bus-bar energy costs



Note: See Appendix B for wind technology cost and performance projections; PTC and transmission and integration costs are excluded.

Figure 1-6. Supply curve for wind energy—energy costs including connection to 10% of existing transmission grid capacity



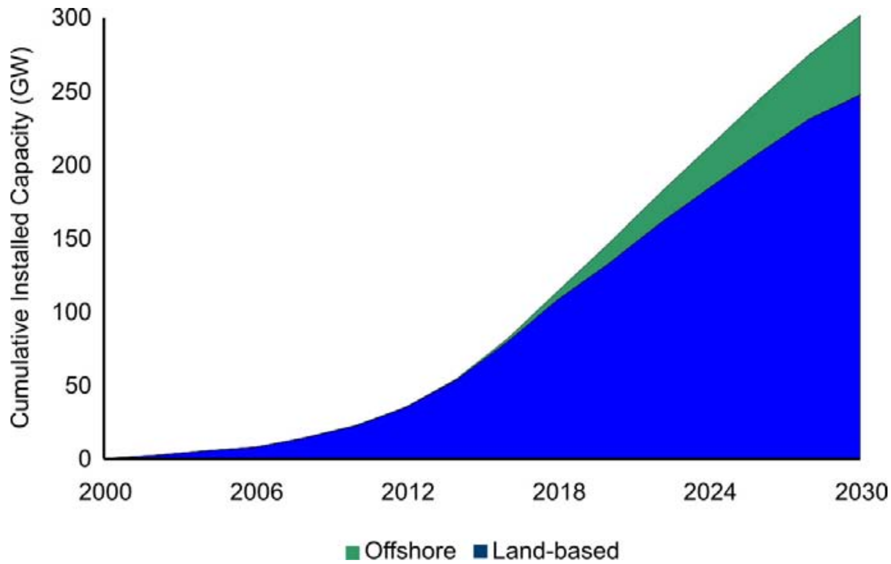
Note: See Appendix B for wind technology cost and performance projections. Excludes PTC, includes transmission costs to access existing electric transmission within 500 miles of wind resource.

much as 600 GW of wind resources could be available for $60 to $100 per megawatt-hour (MWh), including the cost of connecting to the existing transmission system. Including the PTC reduces the cost by about $20/MWh, and costs are further reduced if technology improvements in cost and performance are projected. In some cases, new transmission lines connecting high-wind resource areas to load centers could be cost-effective, and in other cases, high transmission costs could offset the advantage of land-based generation, as in the case of large demand centers along wind-rich coastlines.

NREL's WinDS model estimated the overall U.S. generation capacity expansion that is required to meet projected electricity demand growth through 2030. Both wind technology and conventional generation technology (i.e., coal, nuclear) were included in the modeling, but other renewables were not included. Readers should refer to Appendices A and B to see a more complete list of the modeling assumptions. Wind energy development for the 20% Wind Scenario optimized the total delivered costs, including future reductions in cost per kilowatt-hour for wind sites both near to and remote from demand sites from 2000 through 2030.[5] Chapter 2 presents additional discussion of wind technology potential. Of the 293 GW that would be added, the model specifies more than 50 GW of offshore wind energy (see Figure 1-7), mostly along the northeastern and southeastern seaboards.

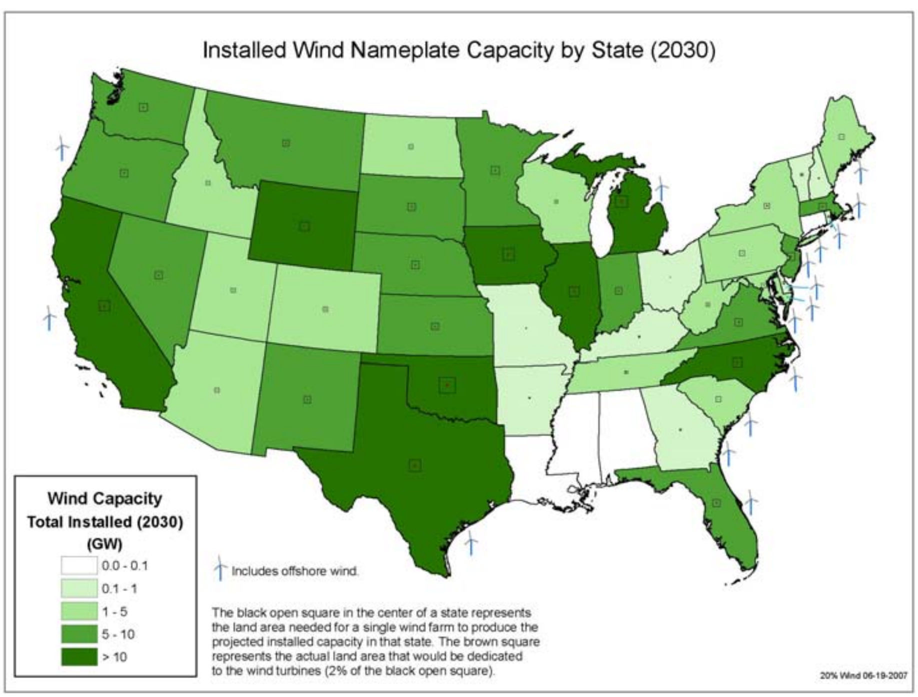
[5] The modeling assumptions prescribed annual wind energy generation levels that reached 20% of projected demand by 2030 so as to demonstrate technical feasibility and quantify costs and impacts. Policy options that would help induce this growth trajectory were not included. It is assumed that a stable policy environment that recognizes wind's benefits could lead to growth rates that would result in the 20% Wind Scenario.

Figure 1-7. 20% cumulative installed wind power capacity required to produce 20% of projected electricity by 2030



Based on this least-cost optimization algorithm (which incorporates future cost per kilowatt-hour of wind and cost of transmission), the WinDS model estimated the wind capacity needed by state by 2030. As shown in Figure 1-8, most states would have the opportunity to develop their wind resources. Total land requirements are extensive, but only about 2% to 5% of the total would be dedicated entirely to the wind installation. In addition, the visual impacts and other siting concerns of wind energy projects must be taken into account in assessing land requirements. Chapter 5 contains additional discussion of land use and visual impacts. Again, the 20% Wind Scenario presented here is not a prediction. Figure 1-8 simply shows one way in which a 20% wind future could evolve.

Figure 1-8. 46 states would have substantial wind development by 2030



Land Requirements

Altogether, new land-based installations would require approximately 50,000 square kilometers (km^2) of land, yet the actual footprint of land-based turbines and related infrastructure would require only about 1,000 to 2,500 km^2 of dedicated land—slightly less than the area of Rhode Island.

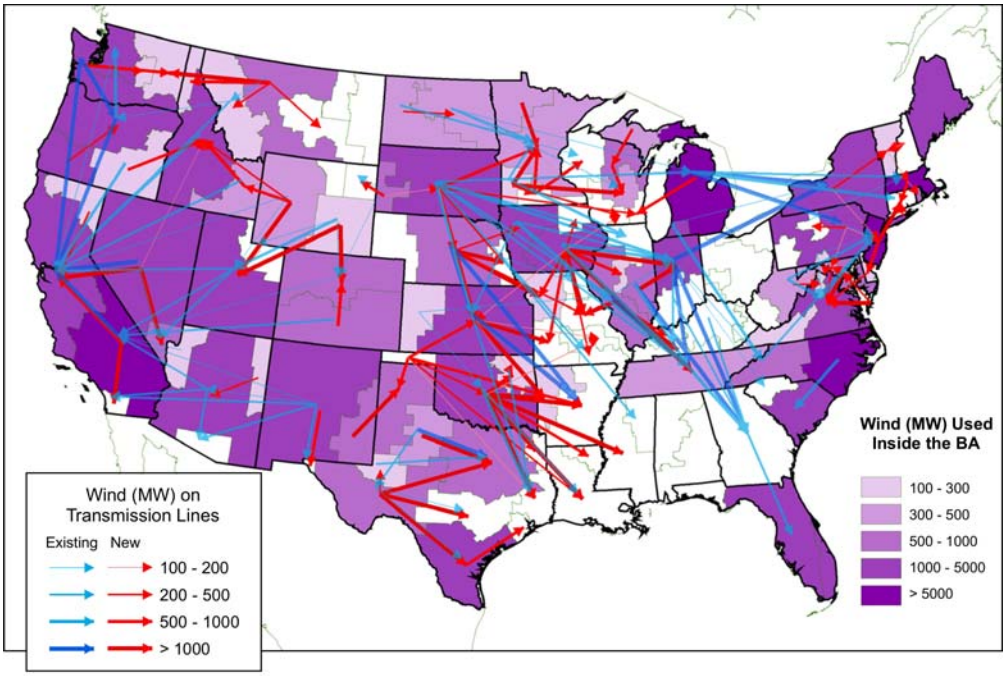
The 20% Wind Scenario envisions 251 GW of land-based and 54 GW of shallow offshore wind capacity to optimize delivered costs, which include both generation and transmission.

Wind capacity levels in each state depend on a variety of assumptions and the national optimization of electricity generation expansion. Based on the perspectives of industry experts and near-term wind development plans, wind capacity in Ohio was modified and offshore wind development in Texas was included. In reality, each state's wind capacity level will vary significantly as electricity markets evolve and state policies promote or restrict the energy production of electricity from wind and other renewable and conventional energy sources.

1.2.2 WIND POWER TRANSMISSION AND INTEGRATION

Development of 293 GW of new wind capacity would require expanding the U.S. transmission grid in a manner that not only accesses the best wind resource regions of the country but also relieves current congestion on the grid, including new transmission lines to deliver wind power to electricity consumers. Figure 1-9 conceptually illustrates the optimized use of wind resources within the local areas as well as the transmission of wind-generated electricity from high-resource areas to high-demand centers. This data was generated by the WinDS model (given prescribed constraints). The figure does not represent proposals for specific transmission lines.

Figure 1-9. All new electricity generation including wind energy would require expansion of U.S. transmission by 2030

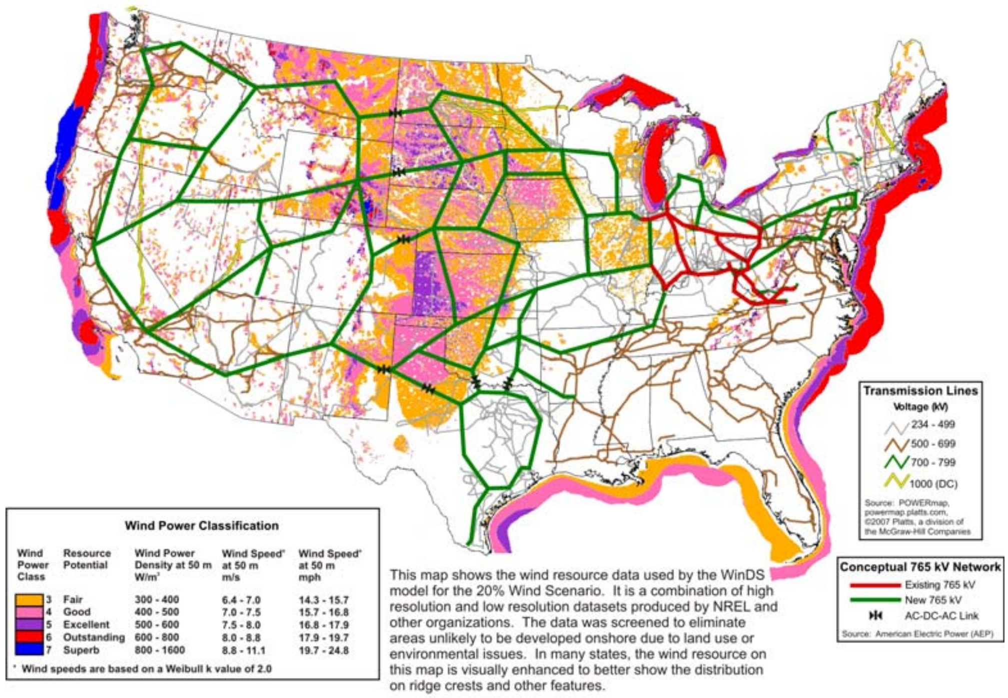


Total Between Balancing Areas Transfer >= 100 MW (all power classes, land-based and offshore) in 2030.
Wind power can be used locally within a Balancing Area (BA), represented by purple shading, or transferred out of the area on new or existing transmission lines, represented by red or blue arrows. Arrows originate and terminate at the centroid of the BA for visualization purposes; they do not represent physical locations of transmission lines.

Figure 1-10 displays transmission needs in the form of one technically feasible transmission grid as a 765 kV overlay. A complete discussion of transmission issues can be found in Chapter 4.

Until recently, concerns had been prevalent in the electric utility sector about the difficulty and cost of dealing with the variability and uncertainty of energy production from wind plants and other weather-driven renewable technologies. But utility engineers in some parts of the United States now have extensive experience with wind plant impacts, and their analyses of these impacts have helped to reduce these concerns. As discussed in detail in Chapter 4, wind's variability is being accommodated, and given optimistic assumptions, studies suggest the cost impact could be as little as the current level—10% or less of the value of the wind energy generated.

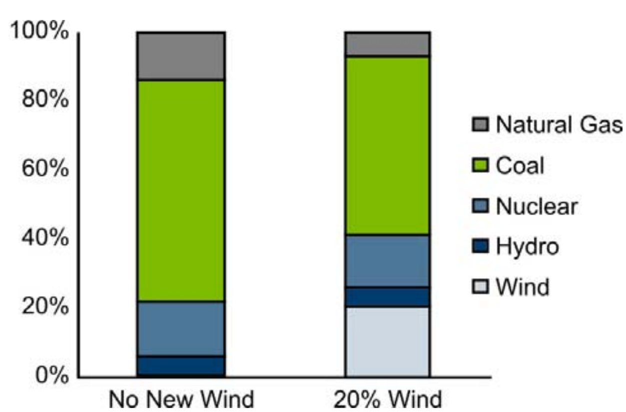
Figure 1-10. Conceptual transmission plan to accommodate 400 GW of wind energy (AEP 2007)



1.2.3 Electrical Energy Mix

The U.S. Energy Information Administration (EIA) estimates that U.S. electricity demand will grow by 39% from 2005 to 2030, reaching 5.8 billion MWh by 2030. The 20% Wind Scenario would require delivery of nearly 1.16 billion MWh of wind energy in 2030, altering U.S. electricity generation as shown in Figure 1-11. In this scenario, wind would supply enough energy to displace about 50% of electric utility natural gas consumption and 18% of coal consumption by 2030. This amounts to an 11% reduction in natural gas across all industries. (Gas-fired generation would probably be displaced first, because it typically has a higher cost.)

Figure 1-11. U.S. electrical energy mix



The increased wind development in this scenario could reduce the need for new coal and combined cycle natural gas capacity, but would increase the need for additional combustion turbine natural gas capacity to maintain electric system reliability. These units, though, would be run only as needed.[6]

1.2.4 Pace of New Wind Installations

Manufacturing capacity would require time to ramp up enough to support rapid growth in new U.S. wind installations. The 20% Wind Scenario estimates that the installation rate would need to

[6] Appendix A presents a full analysis of changes in the capacity mix and energy generation under the 20% Wind Scenario.

increase from installing 3 GW per year in 2006 to more than 16 GW per year by 2018 and to continue at roughly that rate through 2030, as seen in Figure 1-4. This increase in installation rate, although quite large, is comparable to the recent annual installation rate of natural gas units, which totaled more than 16 GW in 2005 alone (EIA 2005).

The assumptions of the 20% Wind Scenario form the foundation for the technical analyses presented in the remaining chapters. This overview is provided as context for the potential impacts and technical challenges discussed in the next sections.

Wind vs. Traditional Electricity Generation

Wind power avoids several of the negative effects of traditional electricity generation from fossil fuels:

- Emissions of mercury or other heavy metals into the air
- Emissions associated with extracting and transporting fuels
- Lake and streambed acidification from acid rain or mining
- Water consumption associated with mining or electricity generation
- Production of toxic solid wastes, ash, or slurry
- Greenhouse gas (GHG) emissions

1.3 IMPACTS

The 20% Wind Scenario presented here offers potentially positive impacts in terms of greenhouse gas (GHG) reductions, water conservation, and energy security, as compared to the base case of no wind growth in this analysis. However, tapping this resource at this level would entail large front-end capital investments to install wind capacity and expanded transmission systems. The impacts described in this section are based largely on the analytical tools and methodology discussed in detail in Appendices A, B, and C.

20% Wind Scenario: Projected Impacts

- **Environment:** Avoids air pollution and reduces GHG emissions; reduces electric sector CO_2 emissions by 825 million metric tons annually
- **Water savings:** Reduces cumulative water use in the electric sector by 8% (4 trillion gallons)
- **U.S. energy security:** Diversifies electricity portfolio and represents an indigenous energy source with stable prices not subject to fuel volatility
- **Energy consumers:** Potentially reduces demand for fossil fuels, in turn reducing fuel prices and stabilizing electricity rates
- **Local economics:** Creates new income source for rural landowners and tax revenues for local communities in wind development areas
- **American workers:** Generates well-paying jobs in sectors that support wind development, such as manufacturing, engineering, construction, transportation, and financial services; new manufacturing will cause significant growth in wind industry supply chain (see Appendix C)

Wind power would be a critical part of a broad and near-term strategy to substantially reduce air pollution, water pollution, and global climate change associated with traditional generation technologies (see "Wind vs. Traditional Electricity Generation" sidebar). As a domestic energy resource, wind power would also stabilize and diversify national energy supplies.

1.3.1 GREENHOUSE GAS REDUCTIONS

Supplying 20% of U.S. electricity from wind could reduce annual electric sector carbon dioxide (CO_2) emissions by 825 million metric tons by 2030.

20% Wind Scenario: Major Challenges

- Investment in the nation's transmission system, so that the power generated is delivered to urban centers that need the increased supply;
- Larger electric load balancing areas, in tandem with better regional planning, so that regions can depend on a diversity of generation sources, including wind power;
- Continued reduction in wind capital costs and improvement in turbine performance through technology advancement and improved manufacturing capabilities; and
- Addressing potential concerns about local siting, wildlife, and environmental issues within the context of generating electricity.

The threat of climate change and the growing attention paid to it are helping to position wind power as an increasingly attractive option for new power generation. U.S. electricity demand is growing rapidly, and cleaner power sources (e.g., renewable energy) and energy-saving practices (i.e., energy efficiency) could help meet much of the new demand while reducing GHG emissions. Today, wind energy represents approximately 35% of new capacity additions (AWEA 2008). Greater use of wind energy, therefore, presents an opportunity for reducing emissions today as the nation develops additional clean power options for tomorrow.

Concerns about climate change have spurred many industries, policy makers, environmentalists, and utilities to call for reductions in GHG emissions. Although the cost of reducing emissions is uncertain, the most affordable near-term strategy likely involves wider deployment of currently available energy efficiency and clean energy technologies. Wind power is one of the potential supply-side solutions to the climate change problem (Socolow and Pacala 2006).

GHG Reduction

Under the 20% Wind Scenario, a cumulative total of 7,600 million metric tons of CO_2 emissions would be avoided by 2030, and more than 15,000 million metric tons of CO_2 emissions would be avoided through 2050.

Governments at many levels have enacted policies to actively support clean electricity generation, including the renewable energy PTC and state RPS. A growing number of energy and environmental organizations are calling for expanded wind and other renewable power deployment to try to reduce society's carbon footprint.

According to EIA, The United States annually emits approximately 6,000 million metric tons of CO_2. These emissions are expected to increase to nearly 7,900 million metric tons by 2030, with the electric power sector accounting for approximately 40% of the total (EIA 2007). As shown in Figure 1-12, based on the analysis completed for this report, generating 20% of U.S. electricity from wind could avoid approximately 825 million metric tons of CO_2 emissions in the electric sector in 2030. The 20% Wind Scenario would also reduce *cumulative* emissions from the electric sector through that same year by more than 7,600 million metric tons of CO_2 (2,100 million metric tons of carbon equivalent).[7] See Figures 1-12 and 1-13 . In general, CO_2 emission reductions are not only a wind energy benefit but could be achieved under other energy-mix scenarios.

The Fourth Assessment Report of the United Nations Environment Program and World Meteorological Organization's Intergovernmental Panel on Climate Change (IPCC) notes that "Renewable energy generally has a positive effect on energy

[7] CO_2 can be converted to carbon equivalent by multiplying by 12/44. Appendix A presents results in carbon equivalent, not CO_2. Because it assumes a higher share of coal-fired generation, the WinDS model projects higher CO_2 emissions than the EIA model.

Figure 1-12. Annual CO_2 emissions avoided (vertical bars) would reach 825 million metric tons by 2030

The cumulative avoided emissions by 2030 would total 7,600 million metric tons.

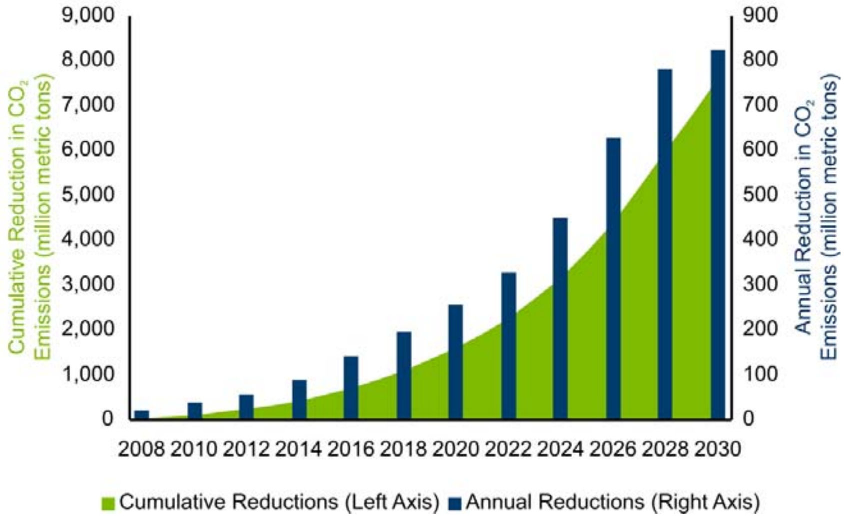
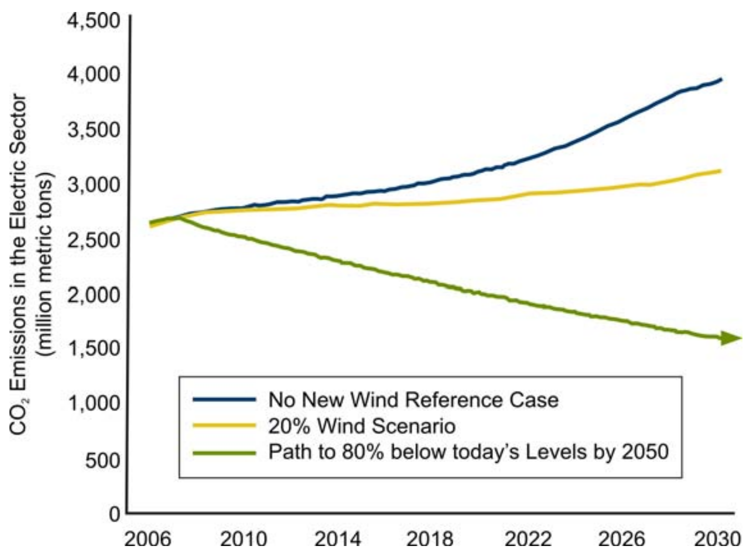


Figure 1-13. CO_2 emissions from the electricity sector



security, employment, and air quality. Given costs relative to other supply options, renewable electricity can have a 30% to 35% share of the total electricity supply in 2030. Deployment of low-GHG (greenhouse gas) emission technologies would be required for achieving stabilization and cost reductions" (IPCC 2007).

More than 30 U.S. states have created climate action plans. In addition, the Regional Greenhouse Gas Initiative (RGGI) is a 10-state collaborative in the Northeast to address CO_2 emissions. All of these state and regional efforts include wind energy as part of a portfolio strategy to reduce overall emissions from energy production (RGGI 2006).

Because wind turbines typically have a service life of at least 20 years and transmission lines can last more than 50 years, investments in achieving 20% wind power by 2030 could continue to supply clean energy through at least 2050. As a result, the cumulative climate change impact of achieving 20% wind power could grow to more than 15,000 million metric tons of CO_2 emissions avoided by mid-century (4,182 million metric tons of carbon equivalent).

The 20% Wind Scenario constructed here would displace a significant amount of fossil fuel generation. According to the WinDS model, by 2030, wind generation is projected to displace 50% of electricity generated from natural gas and 18% of that generated from coal. The displacement of coal is of particular interest because it provides a comparatively higher carbon emissions reduction opportunity. Recognizing that coal power will continue to play a major role in future electricity generation, a large increase in total wind capacity could potentially defer the need to build some new coal capacity, avoiding or postponing the associated increases in carbon emissions. Current DOE projections anticipate construction of approximately 140 GW of new coal plant capacity by 2030 (EIA 2007); the 20% Wind Scenario could avoid construction of more than 80 GW of new coal capacity.[8]

Wind energy that displaces fossil fuel generation can also help meet existing regulations for emissions of conventional pollutants, including sulfur dioxide, nitrogen oxides, and mercury.

1.3.2 Water Conservation

The 20% scenario would potentially reduce cumulative water consumption in the electric sector by 8% (or 4 trillion gallons) from 2007 through 2030—significantly reducing water consumption in the arid states of the interior West. In 2030, annual water consumption in the electric sector would be reduced by 17%.

Wind Reduces Vulnerability

Continued reliance on natural gas for new power generation is likely to put the United States in growing competition in world markets for liquefied natural gas (LNG)—some of which will come from Russia, Qatar, Iran, and other nations in less-than-stable regions.

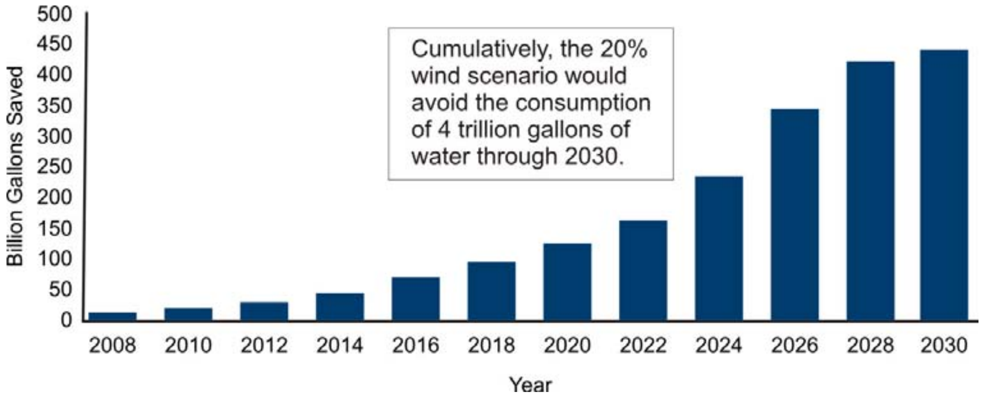
Water scarcity is a significant problem in many parts of the United States. Even so, few U.S. citizens realize that electricity generation accounts for nearly 50% of all water withdrawals in the nation, with irrigation withdrawals coming in second at 34% (USGS 2005). Water is used for the cooling of natural gas, coal, and nuclear power plants and is an increasing part of the challenge in developing those resources.

Although a significant portion of the water withdrawn for electricity production is recycled back through the system, approximately 2% to 3% of the water withdrawn is consumed through evaporative losses. Even this small fraction adds up to approximately 1.6 to 1.7 trillion gallons of water consumed for power generation each year.

As additional wind generation displaces fossil fuel generation, each megawatt-hour generated by wind could save as much as 600 gallons of water that would otherwise

[8] Carbon mitigation policies were not modeled in either the 20% Wind or No New Wind Scenarios, which results in conventional generation mixes typical of current generation capacity. Under carbon mitigation scenarios, additional technologies could be implemented to reduce the need for conventional generation technology (see Appendix A).

Figure 1-14. National water savings from the 20% Wind Scenario



be lost to fossil plant cooling.[9] Because wind energy generation uses a negligible amount of water, the 20% Wind Scenario would avoid the consumption of 4 trillion gallons of water through 2030, a cumulative reduction of 8%, with annual reductions through 2030 shown in Figure 1-14. The annual savings in 2030 is approximately 450 billion gallons. This savings would reduce the expected annual water consumption for electricity generation in 2030 by 17%. The projected water savings are dependent on a future generation mix, which is discussed further in Appendix A.

Based on the WinDS modeling results, nearly 30% of the projected water savings from the 20% Wind Scenario would occur in western states, where water resources are particularly scarce. The Western Governors Association (WGA) highlights this concern in its Clean and Diversified Energy Initiative, which recognizes increased water consumption as a key challenge in accommodating rapid growth in electricity demand. In its 2006 report on water needs, the WGA states that "difficult political choices will be necessary regarding future economic and environmental uses of water and the best way to encourage the orderly transition to a new equilibrium" (WGA 2006).

1.3.3 Energy Security and Stability

There is broad and growing recognition that the nation should diversify its energy portfolio so that a supply disruption affecting a single energy source will not significantly disrupt the national economy. Developing domestic energy sources with known and stable costs would significantly improve U.S. energy stability and security.

When electric utilities have a Power Purchase Agreement or own wind turbines, the price of energy is expected to remain relatively flat and predictable for the life of the wind project, given that there are no fuel costs and assuming that the machines are well maintained. In contrast, a large part of the cost of coal- and gas-fired electricity is in the fuel, for which prices are often volatile and unpredictable. Fuel price risks reduce security and stability for U.S. manufacturers and consumers, as well as for the U.S. economy as a whole. Even small reductions in the amount of energy available or changes in the price of fuel can cause large economic disruptions across the nation. This capacity to disrupt was clearly illustrated by the 1973 embargo imposed by the Organization of Arab Petroleum Exporting Countries (the "Arab oil embargo"); the 2000–2001 California electricity market problems; and the gasoline

[9] See Appendix A for specific assumptions.

and natural gas shortages and price spikes that followed the 2005 hurricane damage to oil refinery and natural gas processing facilities along the Gulf Coast.

Using wind energy increases security and stability by diversifying the national electricity portfolio. Just as those investing for retirement are advised to diversify investments across companies, sectors, and stocks and bonds, diversification of electricity supplies helps distribute the risks and stabilize rates for electricity consumers.

Wind energy reduces reliance on foreign energy sources from politically unstable regions. As a domestic energy source, wind requires no imported fuel, and the turbine components can be either produced on U.S. soil or imported from any friendly nation with production capabilities.

Energy security concerns for the electric industry will likely increase in the foreseeable future as natural gas continues to be a leading source of new generation supply. With declining domestic natural gas sources, future natural gas supplies are expected to come in the form of liquefied natural gas (LNG) imported on tanker ships. U.S. imports of LNG could quadruple by 2030 (EIA 2007). Almost 60% of uncommitted natural gas reserves are in Iran, Qatar, and Russia. These countries, along with others in the Middle East, are expected to be major suppliers to the global LNG market. Actions by those sources can disrupt international energy markets and thus have indirect adverse effects on our economy. Additional risks arise from competition for these resources caused by the growing energy demands of China, India, and other developing nations. According to the WinDS model results, under the 20% Wind Scenario, wind energy could displace approximately 11% of natural gas consumption, which is equivalent to 60% of expected LNG imports in 2030.[10] This displacement would reduce the nation's energy vulnerability to uncertain natural gas supplies. See Appendix A for gas demand reduction assumptions and calculations.

Continued reliance on fossil energy sources exposes the nation to price risks and supply uncertainties. Although the electric sector does not rely heavily on petroleum, which represents one of the nation's biggest energy security threats, diversifying the electric generation mix with increased domestic renewable energy would still enhance national energy security by increasing energy diversity and price stability.

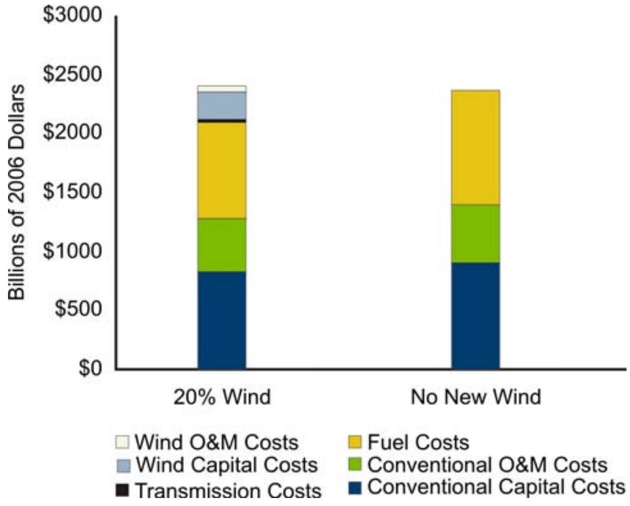
1.3.4 Cost of the 20% Wind Scenario

The overall economic cost of the 20% Wind Scenario accrues mainly from the incremental costs of wind energy relative to other generation sources. This is impacted by the assumptions behind the scenario, listed in Table A-1. Also, some incremental transmission would be required to connect wind to the electric power system. This transmission investment would be in addition to the significant investment in the electric grid that will be needed to serve continuing load growth, whatever the mix of new generation. The market cost of wind energy remains higher than that of conventional energy sources in many areas across the country. In addition, the transmission grid would have to be expanded and upgraded in wind-rich areas and across the existing system to deliver wind energy to many demand centers. An integrated approach to expanding the transmission system would need to include furnishing access to wind resources as well as meeting other system needs.

[10] Compared to consumption of the high price scenario of EIA (2007), used in this report.

Compared to other generation sources, the 20% Wind Scenario entails higher initial capital costs (to install wind capacity and associated transmission infrastructure) in many areas, yet offers lower ongoing energy costs for operations, maintenance, and fuel. Given the optimistic cost and performance assumptions of wind and

Figure 1-15. Incremental investment cost of 20% wind is modest; a difference of 2%



conventional energy sources (detailed in Appendix B), the 20% Wind Scenario could require an incremental investment of as little as $43 billion net present value (NPV) more than the base-case scenario involving no new wind power generation (No New Wind Scenario). This would represent less than 0.06 cents (6 one-hundredths of 1 cent) per kilowatt-hour of total generation by 2030, or roughly 50 cents per month per household. Figure 1-15 shows this cost comparison. The base-case costs are calculated under the assumption of no major changes in fuel availability or environmental restrictions. In this scenario, the cost differential would be about 2% of a total NPV expenditure exceeding $2 trillion.

This analysis is intended to identify the incremental cost of pursuing the 20% Wind Scenario. In regions where the capital costs of the 20% Wind Scenario exceed those of building little or no additional wind capacity, the differential could be offset by the operating costs and benefits discussed earlier. For example, even though Figure 1-15 shows that under optimistic assumptions, the 20% Wind Scenario could increase total capital costs by nearly $197 billion, most of those costs would be offset by the nearly $155 billion in decreased fuel expenditures, resulting in a net incremental cost of approximately $43 billion in NPV. These monetary costs do not reflect other potential offsetting positive impacts.

As estimated by the NREL WinDS model, given optimistic assumptions, the specific cost of the proposed transmission expansion for the 20% Wind Scenario is $20 billion in NPV. The actual required grid investment could also involve significant costs for permitting delays, construction of grid extensions to remote areas with wind resources, and investments in advanced grid controls, integration, and training to enable regional load balancing of wind resources.

The total installed costs for wind plants include costs associated with siting and permitting of these plants. It has become clear that wind power expansion would require careful, logical, and fact-based consideration of local and environmental concerns, allowing siting issues to be addressed within a broad risk framework. Experience in many regions has shown that this can be done, but efficient, streamlined procedures will likely be needed to enable installation rates in the range of 16 GW per year. Chapter 5 covers these issues in more detail.

1.4 Conclusion

There are significant costs, challenges, and impacts associated with the 20% Wind Scenario presented in this report. There are also substantial positive impacts from wind power expansion on the scale and pace described in this chapter that are not likely to be realized in a business-as-usual future. Achieving the 20% Wind Scenario would involve a major national commitment to clean, domestic energy sources with minimal emissions of GHGs and other environmental pollutants.

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Chapter 2. Wind Turbine Technology

Today's wind technology has enabled wind to enter the electric power mainstream. Continued technological advancement would be required under the 20% Wind Scenario.

2.1 INTRODUCTION

Current turbine technology has enabled wind energy to become a viable power source in today's energy market. Even so, wind energy provides approximately 1% of total U.S. electricity generation. Advancements in turbine technology that have the potential to increase wind energy's presence are currently being explored. These areas of study include reducing capital costs, increasing capacity factors, and mitigating risk through enhanced system reliability. With sufficient research, development, and demonstration (RD&D), these new advances could potentially have a significant impact on commercial product lines in the next 10 years.

A good parallel to wind energy evolution can be derived from the history of the automotive industry in the United States. The large-scale production of cars began with the first Model T production run in 1910. By 1940, after 30 years of making cars and trucks in large numbers, manufacturers had produced vehicles that could reliably move people and goods across the country. Not only had the technology of the vehicle improved, but the infrastructure investment in roads and service stations made their use practical. Yet 30 years later, in 1970, one would hardly recognize the vehicles or infrastructure as the same as those in 1940. Looking at the changes in automobiles produced over that 30-year span, we see how RD&D led to the continuous infusion of modern electronics; improved combustion and manufacturing processes; and ultimately, safer, more reliable cars with higher fuel efficiency. In a functional sense, wind turbines now stand roughly where the U.S. automotive fleet stood in 1940. Gradual improvements have been made in the past 30 years over several generations of wind energy products. These technology advances enable today's turbines to reliably deliver electricity to the grid at a reasonable cost.

Through continued RD&D and infrastructure development, great strides will be made to produce even more advanced machines supporting future deployment of wind power technology. This chapter describes the status of wind technology today and provides a brief history of technology development over the past three decades. Prospective improvements to utility-scale land-based wind turbines as well as offshore wind technology are discussed. Distributed wind technology [100 kilowatts (kW) or less] is also addressed in this chapter.

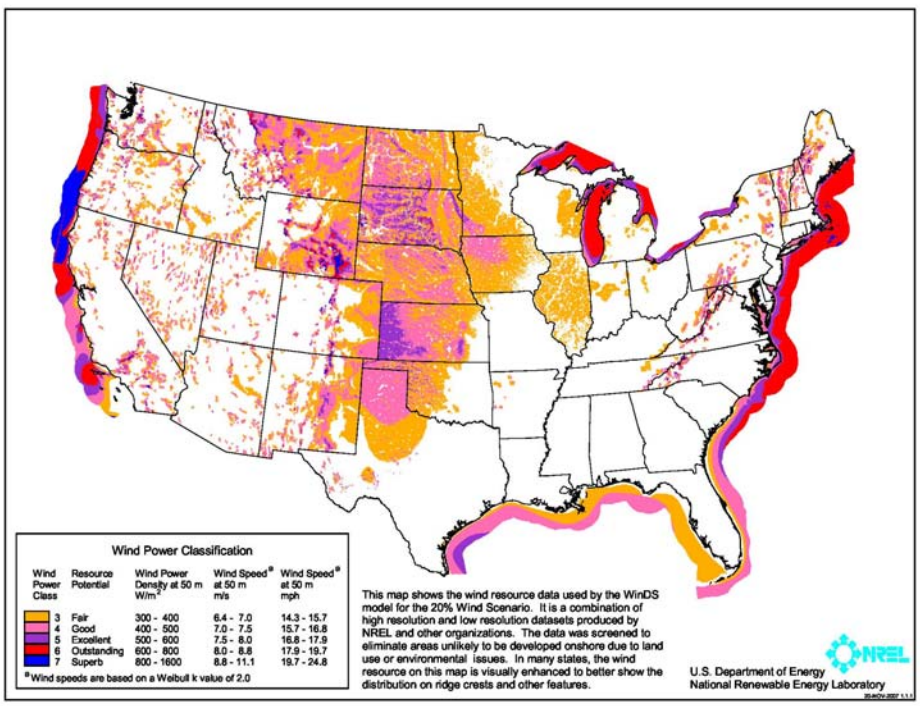
2.2 TODAY'S COMMERCIAL WIND TECHNOLOGY

Beginning with the birth of modern wind-driven electricity generators in the late 1970s, wind energy technology has improved dramatically up to the present. Capital costs have decreased, efficiency has increased, and reliability has improved. High-quality products are now routinely delivered by major suppliers of turbines around the world, and complete wind generation plants are being engineered into the grid infrastructure to meet utility needs. In the 20% Wind Scenario outlined in this report, it is assumed that capital costs would be reduced by 10% over the next two decades, and capacity factors would be increased by about 15% (corresponding to a 15% increase in annual energy generation by a wind plant).

2.2.1 WIND RESOURCES

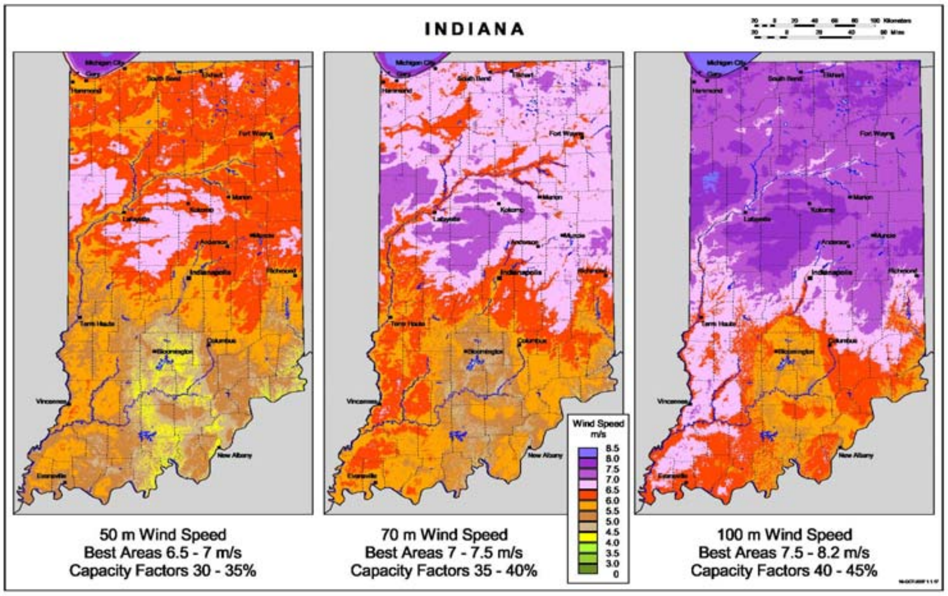
Wind technology is driven by the nature of the resource to be harvested. The United States, particularly the Midwestern region from Texas to North Dakota, is rich in wind energy resources as shown in Figure 2-1, which illustrates the wind resources measured at a 50-meter (m) elevation. Measuring potential wind energy generation at a 100-m elevation (the projected operating hub height of the next generation of modern turbines) greatly increases the U.S. land area that could be used for wind deployment, as shown in Figure 2-2 for the state of Indiana. Taking these measurements into account, current U.S. land-based and offshore wind resources are estimated to be sufficient to supply the electrical energy needs of the entire country several times over. For a description of U.S. wind resources, see Appendix B.

Figure 2-1. The wind resource potential at 50 m above ground on land and offshore



Identifying the good wind potential at high elevations in states such as Indiana and off the shore of both coasts is important because it drives developers to find ways to harvest this energy. Many of the opportunities being pursued through advanced

Figure 2-2. Comparison of the wind energy resource at 50 m, 70 m, and 100 m for Indiana



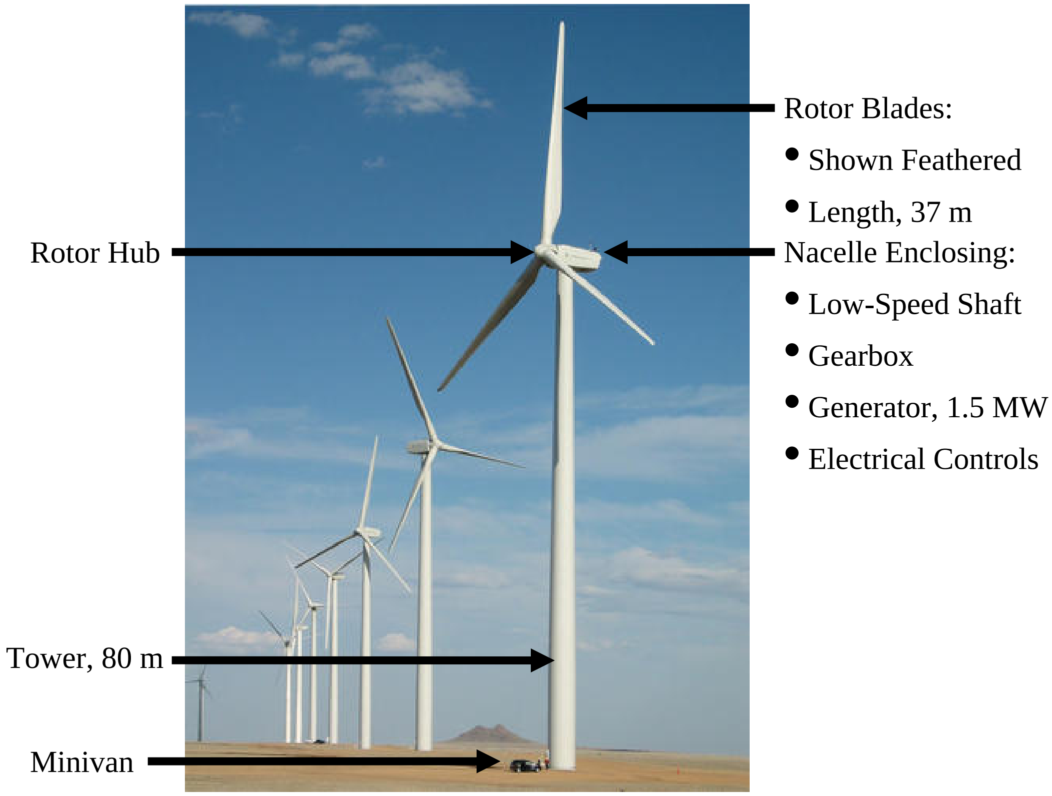
technology are intended to achieve higher elevations, where the resource is much greater, or to access extensive offshore wind resources.

2.2.2 Today's Modern Wind Turbine

Modern wind turbines, which are currently being deployed around the world, have three-bladed rotors with diameters of 70 m to 80 m mounted atop 60-m to 80-m towers, as illustrated in Figure 2-3. Typically installed in arrays of 30 to 150 machines, the average turbine installed in the United States in 2006 can produce approximately 1.6 megawatts (MW) of electrical power. Turbine power output is controlled by rotating the blades around their long axis to change the angle of attack with respect to the relative wind as the blades spin around the rotor hub. This is called controlling the blade pitch. The turbine is pointed into the wind by rotating the nacelle around the tower. This is called controlling the yaw. Wind sensors on the nacelle tell the yaw controller where to point the turbine. These wind sensors, along with sensors on the generator and drivetrain, also tell the blade pitch controller how to regulate the power output and rotor speed to prevent overloading the structural components. Generally, a turbine will start producing power in winds of about 5.36 m/s and reach maximum power output at about 12.52 m/s–13.41 m/s. The turbine will pitch or feather the blades to stop power production and rotation at about 22.35 m/s. Most utility-scale turbines are upwind machines, meaning that they operate with the blades upwind of the tower to avoid the blockage created by the tower.

The amount of energy in the wind available for extraction by the turbine increases with the cube (the third power) of wind speed; thus, a 10% increase in wind speed creates a 33% increase in available energy. A turbine can capture only a portion of this cubic increase in energy, though, because power above the level for which the electrical system has been designed, referred to as the rated power, is allowed to pass through the rotor.

Figure 2-3. A modern 1.5-MW wind turbine installed in a wind power plant



In general, the speed of the wind increases with the height above the ground, which is why engineers have found ways to increase the height and the size of wind turbines while minimizing the costs of materials. But land-based turbine size is not expected to grow as dramatically in the future as it has in the past. Larger sizes are physically possible; however, the logistical constraints of transporting the components via highways and of obtaining cranes large enough to lift the components present a major economic barrier that is difficult to overcome. Many turbine designers do not expect the rotors of land-based turbines to become much larger than about 100 m in diameter, with corresponding power outputs of about 3 MW to 5 MW.

2.2.3 Wind Plant Performance and Price

The performance of commercial turbines has improved over time, and as a result, their capacity factors have slowly increased. Figure 2-4 shows the capacity factors at commercial operation dates (CODs) ranging from 1998 to 2005. The data show that turbines in the Lawrence Berkeley National Laboratory (Berkeley Lab) database (Wiser and Bolinger 2007) that began operating commercially before 1998 have an average capacity factor of about 22%. The turbines that began commercial operation after 1998, however, show an increasing capacity factor trend, reaching 36% in 2004 and 2005.

The cost of wind-generated electricity has dropped dramatically since 1980, when the first commercial wind plants began operating in California. Since 2003, however, wind energy prices have increased. Figure 2-5 (Wiser and Bolinger 2007)

Figure 2-4. Turbine capacity factor by commercial operation date (COD) using 2006 data

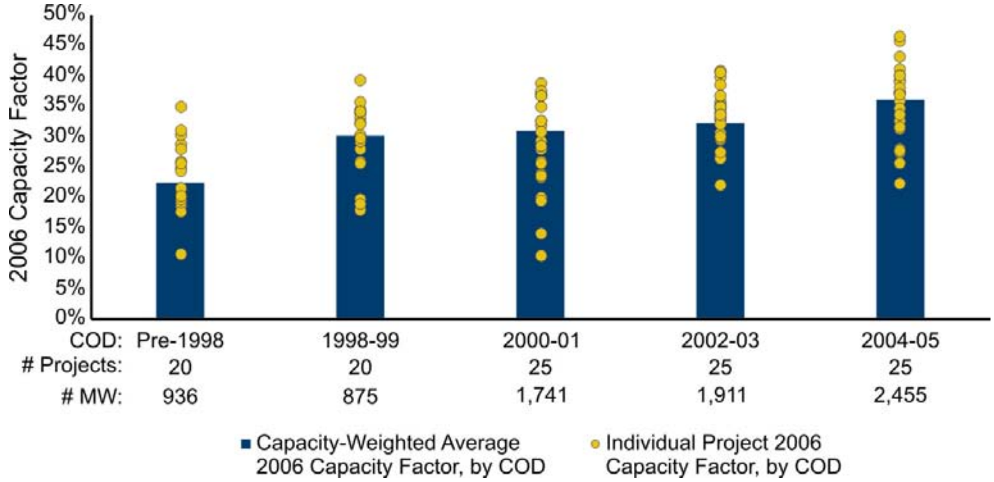
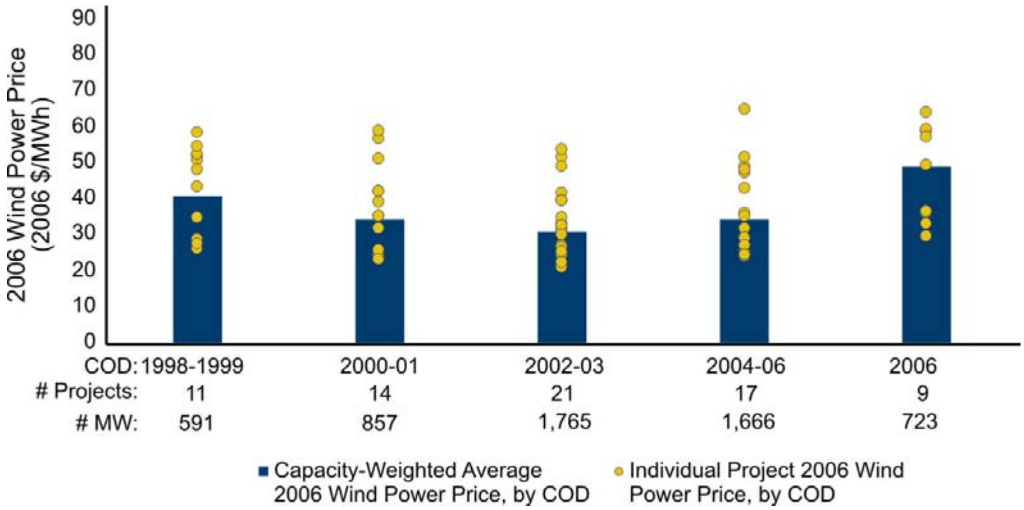


Figure 2-5. Wind energy price by commercial operation date (COD) using 2006 data



shows that in 2006 the price paid for electricity generated in large wind farms was between 3.0 and 6.5 cents/kilowatt-hour (kWh), with an average near 5 cents/kWh (1 cent/kWh = $10/megawatt-hour [MWh]). This price includes the benefit of the federal production tax credit (PTC), state incentives, and revenue from the sale of any renewable energy credits.

Wind energy prices have increased since 2002 for the following reasons (Wiser and Bolinger 2007):

- Shortages of turbines and components, resulting from the dramatic recent growth of the wind industry in the United States and Europe
- The weakening U.S. dollar relative to the euro (many major turbine components are imported from Europe, and there are relatively few wind turbine component manufacturers in the United States)

- A significant rise in material costs, such as steel and copper, as well as transportation fuels over the last three years
- The on-again, off-again cycle of the wind energy PTC (uncertainty hinders investment in new turbine production facilities and encourages hurried and expensive production, transportation, and installation of projects when the tax credit is available).

Expected future reductions in wind energy costs would come partly from expected investment in the expansion of manufacturing volume in the wind industry. In addition, a stable U.S. policy for renewable energy and a heightened RD&D effort could also lower costs.

2.2.4 Wind Technology Development

Until the early 1970s, wind energy filled a small niche market, supplying mechanical power for grinding grain and pumping water, as well as electricity for rural battery charging. With the exception of battery chargers and rare experiments with larger electricity-producing machines, the windmills of 1850 and even 1950 differed very little from the primitive devices from which they were derived. Increased RD&D in the latter half of the twentieth century, however, greatly improved the technology.

In the 1980s, the practical approach of using low-cost parts from agricultural and boat-building industries produced machinery that usually worked, but was heavy, high-maintenance, and grid-unfriendly. Little was known about structural loads caused by turbulence, which led to the frequent and early failure of critical parts, such as yaw drives. Additionally, the small-diameter machines were deployed in the California wind corridors, mostly in densely packed arrays that were not aesthetically pleasing in such a rural setting. These densely packed arrays also often blocked the wind from neighboring turbines, producing a great deal of turbulence for the downwind machines. Reliability and availability suffered as a result.

Recognizing these issues, wind operators and manufacturers have worked to develop better machines with each new generation of designs. Drag-based devices and simple lift-based designs gave way to experimentally designed and tested high-lift rotors, many with full-span pitch control. Blades that had once been made of sail or sheet metal progressed through wood to advanced fiberglass composites. The direct current (DC) alternator gave way to the grid-synchronized induction generator, which has now been replaced by variable-speed designs employing high-speed solid-state switches of advanced power electronics. Designs moved from mechanical cams and linkages that feathered or furled a machine to high-speed digital controls. A 50 kW machine, considered large in 1980, is now dwarfed by the 1.5 MW to 2.5 MW machines being routinely installed today.

Many RD&D advances have contributed to these changes. Airfoils, which are now tested in wind tunnels, are designed for insensitivity to surface roughness and dirt. Increased understanding of aeroelastic loads and the ability to incorporate this knowledge into finite element models and structural dynamics codes make the machines of today more robust but also more flexible and lighter on a relative basis than those of a decade ago.

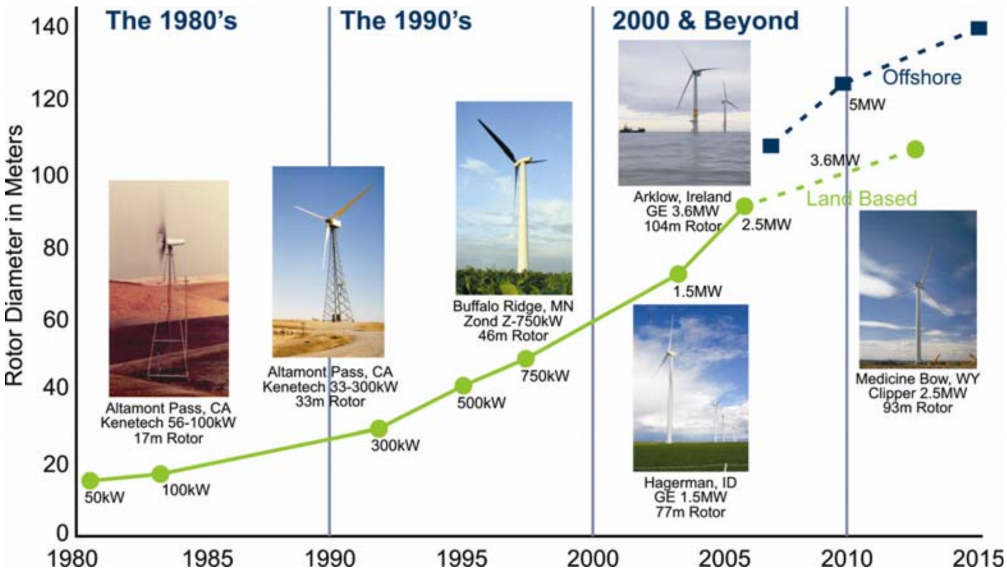
As with any maturing technology, however, many of the simpler and easier improvements have already been incorporated into today's turbines. Increased

RD&D efforts and innovation will be required to continue to expand the wind energy industry.

2.2.5 CURRENT TURBINE SIZE

Throughout the past 20 years, average wind turbine ratings have grown almost linearly, as illustrated by Figure 2-6. Each group of wind turbine designers has predicted that its latest machine is the largest that a wind turbine will ever be. But with each new generation of wind turbines (roughly every five years), the size has grown along the linear curve and has achieved reductions in life-cycle cost of energy (COE).

Figure 2-6. The development path and growth of wind turbines

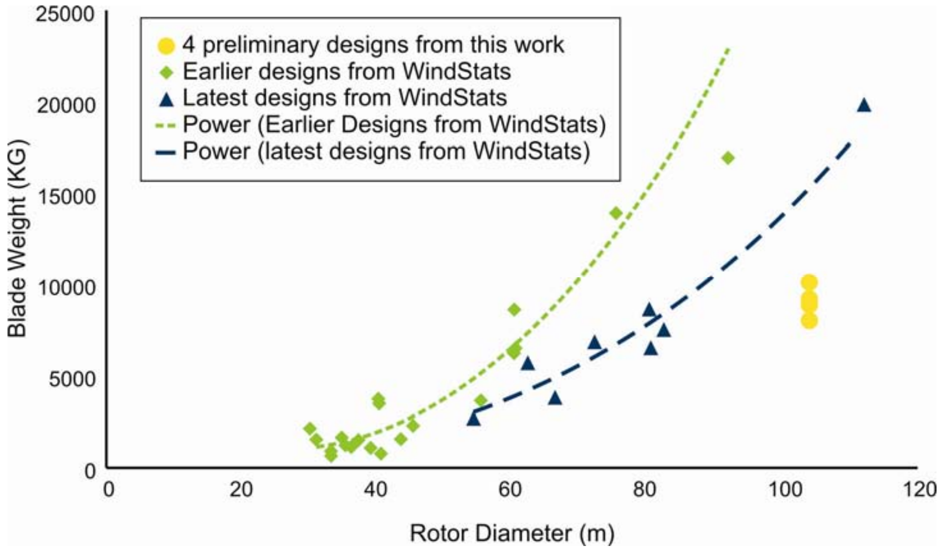


As discussed in Section 2.2.2, this long-term drive to develop larger turbines is a direct result of the desire to improve energy capture by accessing the stronger winds at higher elevations. (The increase in wind speed with elevation is referred to as wind shear.) Although the increase in turbine height is a major reason for the increase in capacity factor over time, there are economic and logistical constraints to this continued growth to larger sizes.

The primary argument for limiting the size of wind turbines is based on the square-cube law. This law roughly states that as a wind turbine rotor grows in size, its energy output increases as the rotor swept area (the diameter squared), while the volume of material, and therefore its mass and cost, increases as the cube of the diameter. In other words, at some size, the cost for a larger turbine will grow faster than the resulting energy output revenue, making scaling a losing economic game.

Engineers have successfully skirted this law by either removing material or using it more efficiently as they increase size. Turbine performance has clearly improved, and cost per unit of output has been reduced, as illustrated in Figures 2-4 and 2-5. A Wind Partnerships for Advanced Component Technology (WindPACT) study has also shown that in recent years, blade mass has been scaling at an exponent of about 2.3 as opposed to the expected 3.0 (Ashwill 2004), demonstrating how successive

Figure 2-7. Growth in blade weight



generations of blade design have moved off the cubic weight growth curve to keep weight down (see Figure 2-7). The latest designs continue to fall below the cubic line of the previous generation, indicating the continued infusion of new technology into blade design. If advanced RD&D were to result in even better design methods, as well as new materials and manufacturing methods that allow the entire turbine to scale as the diameter squared, continuing to innovate around this size limit would be possible.

Land transportation constraints can also limit wind turbine growth for turbines installed on land. Cost-effective road transportation is achieved by remaining within standard over-the-road trailer dimensions of 4.1 m high by 2.6 m wide and a gross vehicle weight (GVW) under 80,000 pounds (lb.; which translates to a cargo weight of about 42,000 lb.). Loads that exceed 4.83 m in height trigger expensive rerouting (to avoid obstructions) and often require utility and law enforcement assistance along the roadways. These dimension limits have the most impact on the base diameter of wind turbine towers. Rail transportation is even more dimensionally limited by tunnel and overpass widths and heights. Overall widths should remain within 3.4 m, and heights are limited to 4.0 m. Transportation weights are less of an issue in rail transportation, with GVW limits of up to 360,000 lb. (Ashwill 2004).

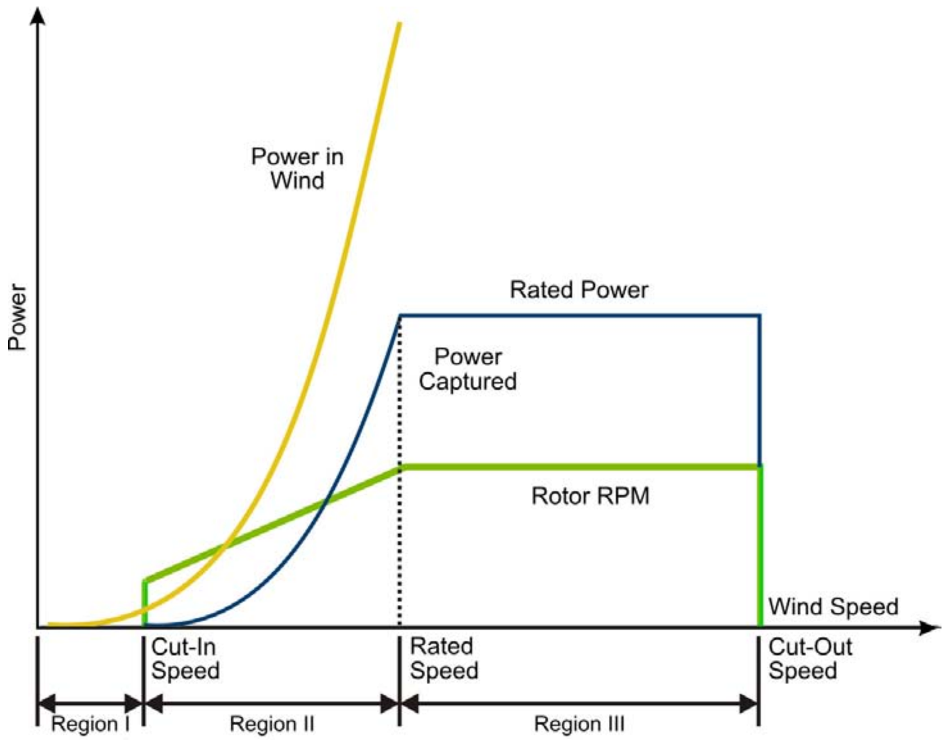
Once turbines arrive at their destination, their physical installation poses other practical constraints that limit their size. Typically, 1.5 MW turbines are installed on 80-m towers to maximize energy capture. Crane requirements are quite stringent because of the large nacelle mass in combination with the height of the lift and the required boom extension. As the height of the lift to install the rotor and nacelle on the tower increases, the number of available cranes with the capability to make this lift is fairly limited. In addition, cranes with large lifting capacities are difficult to transport and require large crews, leading to high operation, mobilization, and demobilization costs. Operating large cranes in rough or complex, hilly terrain can also require repeated disassembly to travel between turbine sites (NREL 2002).

2.2.6 Current Status of Turbine Components

The Rotor

Typically, a modern turbine will cut in and begin to produce power at a wind speed of about 5 m/s (see Figure 2-8). It will reach its rated power at about 12 m/s to 14

Figure 2-8. Typical power output versus wind speed curve



m/s, where the pitch control system begins to limit power output and prevent generator and drivetrain overload. At around 22 m/s to 25 m/s, the control system pitches the blades to stop rotation, feathering the blades to prevent overloads and damage to the turbine's components. The job of the rotor is to operate at the absolute highest efficiency possible between cut-in and rated wind speeds, to hold the power transmitted to the drivetrain at the rated power when the winds go higher, and to stop the machine in extreme winds. Modern utility-scale wind turbines generally extract about 50% of the energy in this stream below the rated wind speed, compared to the maximum energy that a device can theoretically extract, which is 59% of the energy stream (see "The Betz Limit" sidebar).

Most of the rotors on today's large-scale machines have an individual mechanism for pitch control; that is, the mechanism rotates the blade around its long axis to control the power in high winds. This device is a significant improvement over the first generation of fixed-pitch or collective-pitch linkages, because the blades can now be rotated in high winds to feather them out of the wind. This reduces the maximum loads on the system when the machine is parked. Pitching the blades out of high winds also reduces operating loads, and the combination of pitchable blades with a variable-speed generator allows the turbine to maintain generation at a constant rated-power output. The older generation of constant-speed rotors sometimes had instantaneous

The Betz Limit

Not all of the energy present in a stream of moving air can be extracted; some air must remain in motion after extraction. Otherwise, no new, more energetic air can enter the device. Building a wall would stop the air at the wall, but the free stream of energetic air would just flow around the wall. On the other end of the spectrum, a device that does not slow the air is not extracting any energy, either. The maximum energy that can be extracted from a fluid stream by a device with the same working area as the stream cross section is 59% of the energy in the stream. Because it was first derived by wind turbine pioneer Albert Betz, this maximum is known as the Betz Limit.

2

power spikes up to twice the rated power. Additionally, this pitch system operates as the primary safety system because any one of the three independent actuators is capable of stopping the machine in an emergency.

Blades

As wind turbines grow in size, so do their blades—from about 8 m long in 1980 to more than 40 m for many land-based commercial systems and more than 60 m for offshore applications today. Rigorous evaluation using the latest computer analysis tools has improved blade designs, enabling weight growth to be kept to a much lower rate than simple geometric scaling (see Figure 2-7). Designers are also starting to work with lighter and stronger carbon fiber in highly stressed locations to stiffen blades and improve fatigue resistance while reducing weight. (Carbon fiber, however, costs about 10 times as much as fiberglass.) Using lighter blades reduces the load-carrying requirements for the entire supporting structure and saves total costs far beyond the material savings of the blades alone.

By designing custom airfoils for wind turbines, developers have improved blades over the past 20 years. Although these airfoils were primarily developed to help optimize low-speed wind aerodynamics to maximize energy production while limiting loads, they also help prevent sensitivity to blade fouling that is caused by dirt and bug accumulation on the leading edge. This sensitivity reduction greatly improves blade efficiency (Cohen et al. 2008).

Current turbine blade designs are also being customized for specific wind classes. In lower energy sites, the winds are lighter, so design loads can be relaxed and longer blades can be used to harvest more energy in lower winds. Even though blade design methods have improved significantly, there is still much room for improvement, particularly in the area of dynamic load control and cost reduction.

Controls

Today's controllers integrate signals from dozens of sensors to control rotor speed, blade pitch angle, generator torque, and power conversion voltage and phase. The controller is also responsible for critical safety decisions, such as shutting down the turbine when extreme conditions are encountered. Most turbines currently operate in variable-speed mode, and the control system regulates the rotor speed to obtain peak efficiency in fluctuating winds. It does this by continuously updating the rotor speed and generator loading to maximize power and reduce drivetrain transient torque loads. Operating in variable-speed mode requires the use of power converters, which offer additional benefits (which are discussed in the next subsection). Research into the use of advanced control methods to reduce turbulence-induced loads and increase energy capture is an active area of work.

Electrical controls with power electronics enable machines to deliver fault-ride-through control, voltage control, and volt-ampere-reactive (VAR) support to the grid. In the early days of grid-connected wind generators, the grid rules required that wind turbines go offline when any grid event was in progress. Now, with penetration of wind energy approaching 10% in some regions of the United States, more than 8% nationally in Germany, and more than 20% of the average generation in Denmark, the rules are being changed (Wiser and Bolinger 2007). Grid rules on both continents are requiring more support and fault-ride-through protection from the wind generation component. Current electrical control systems are filling this need with wind plants carefully engineered for local grid conditions

The Drivetrain (Gearbox, Generator, and Power Converter)

Generating electricity from the wind places an unusual set of requirements on electrical systems. Most applications for electrical drives are aimed at using electricity to produce torque, instead of using torque to produce electricity. The applications that generate electricity from torque usually operate at a constant rated power. Wind turbines, on the other hand, must generate at all power levels and spend a substantial amount of time at low power levels. Unlike most electrical machines, wind generators must operate at the highest possible aerodynamic and electrical efficiencies in the low-power/low-wind region to squeeze every kilowatt-hour out of the available energy. For wind systems, it is simply not critical for the generation system to be efficient in above-rated winds in which the rotor is letting energy flow through to keep the power down to the rated level. Therefore, wind systems can afford inefficiencies at high power, but they require maximum efficiency at low power—just the opposite of almost all other electrical applications in existence.

Torque has historically been converted to electrical power by using a speed-increasing gearbox and an induction generator. Many current megawatt-scale turbines use a three-stage gearbox consisting of varying arrangements of planetary gears and parallel shafts. Generators are either squirrel-cage induction or wound-rotor induction, with some newer machines using the doubly fed induction design for variable speed, in which the rotor's variable frequency electrical output is fed into the collection system through a solid-state power converter. Full power conversion and synchronous machines are drawing interest because of their fault-ride-through and other grid support capacities.

As a result of fleet-wide gearbox maintenance issues and related failures with some designs in the past, it has become standard practice to perform extensive dynamometer testing of new gearbox configurations to prove durability and reliability before they are introduced into serial production. The long-term reliability of the current generation of megawatt-scale drivetrains has not yet been fully verified with long-term, real-world operating experience. There is a broad consensus that wind turbine drivetrain technology will evolve significantly in the next several years to reduce weight and cost and improve reliability.

The Tower

The tower configuration used almost exclusively in turbines today is a steel monopole on a concrete foundation that is custom designed for the local site conditions. The major tower variable is height. Depending on the wind characteristics at the site, the tower height is selected to optimize energy capture with respect to the cost of the tower. Generally, a turbine will be placed on a 60-m to 80-m tower, but 100-m towers are being used more frequently. Efforts to develop advanced tower configurations that are less costly and more easily transported and installed are ongoing.

Balance of Station

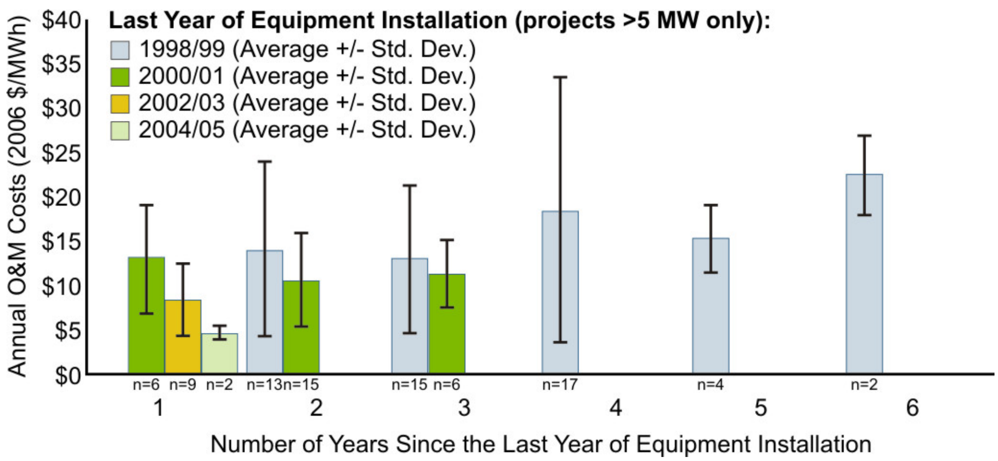
The balance of the wind farm station consists of turbine foundations, the electrical collection system, power-conditioning equipment, supervisory control and data acquisition (SCADA) systems, access and service roads, maintenance buildings, service equipment, and engineering permits. Balance-of-station components contribute about 20% to the installed cost of a wind plant.

2

Operations and Availability

Operation and maintenance (O&M) costs have also dropped significantly since the 1980s as a result of improved designs and increased quality. O&M data from the technology installed well before 2000 show relatively high annual costs that increase with the age of the equipment. Annual O&M costs are reported to be as high as $30-$50/MWh for wind power plants with 1980s technology, whereas the latest generation of turbines has reported annual O&M costs below $10/MWh (Wiser and Bolinger 2007). Figure 2-9 shows annual O&M expenses by wind project age and equipment installation year. Relative to wind power prices shown in Figure 2-5, the O&M costs can be a significant portion of the price paid for wind-generated electricity. Since the late 1990s, modern equipment operation costs have been reduced for the initial operating years. Whether annual operation costs grow as these modern turbines age is yet to be determined and will depend greatly on the quality of these new machines.

Figure 2-9. Operation and maintenance costs for large-scale wind plants installed within the last 10 years for the early years of operation (Wiser and Bolinger 2007)



SCADA systems are being used to monitor very large wind farms and dispatch maintenance personnel rapidly and efficiently. This is one area where experience in managing large numbers of very large machines has paid off. Availability, defined as the fraction of time during which the equipment is ready to operate, is now more than 95% and often reported to exceed 98%. These data indicate the potential for improving reliability and reducing maintenance costs (Walford 2006).

2.3 Technology Improvements on the Horizon

Technology improvements can help meet the cost and performance challenges embedded in this 20% Wind Scenario. The required technological improvements are relatively straightforward: taller towers, larger rotors, and continuing progress through the design and manufacturing learning curve. No single component or design innovation can fulfill the need for technology improvement. By combining a number of specific technological innovations, however, the industry can introduce new advanced architectures necessary for success. The 20% Wind Scenario does not require success in all areas; progress can be made even if only some of the technology innovations are achieved.

2.3.1 Future Improvements to Turbine Components

Many necessary technological advances are already in the active development stages. Substantial research progress has been documented, and individual companies are beginning the development process for these technologies. The risk of introducing new technology at the same time that manufacturing production is scaling up and accelerating to unprecedented levels is not trivial. Innovation always carries risk. Before turbine manufacturers can stake the next product on a new feature, the performance of that innovation needs to be firmly established and the durability needs to be characterized as well as possible. These risks are mitigated by RD&D investment, including extensive component and prototype testing before deployment.

The following are brief summaries of key wind energy technologies that are expected to increase productivity through better efficiency, enhanced energy capture, and improved reliability.

The Rotor

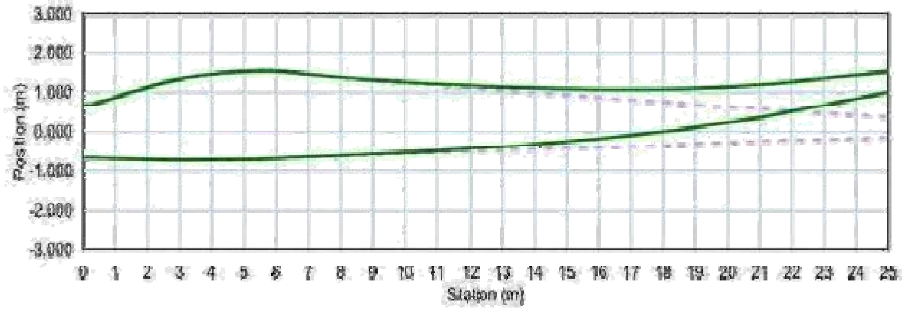
The number one target for advancement is the means by which the energy is initially captured—the rotor. No indicators currently suggest that rotor design novelties are on their way, but there are considerable incentives to use better materials and innovative controls to build enlarged rotors that sweep a greater area for the same or lower loads. Two approaches are being developed and tested to either reduce load levels or create load-resistant designs. The first approach is to use the blades themselves to attenuate both gravity- and turbulence-driven loads (see the following subsection). The second approach lies in an active control that senses rotor loads and actively suppresses the loads transferred from the rotor to the rest of the turbine structure. These improvements will allow the rotor to grow larger and capture more energy without changing the balance of the system. They will also improve energy capture for a given capacity, thereby increasing the capacity factor (Ashwill 2004).

Another innovation already being evaluated at a smaller scale by Energy Unlimited Inc. (EUI; Boise, Idaho) is a variable-diameter rotor that could significantly increase capacity factor. Such a rotor has a large area to capture more energy in low winds and a system to reduce the size of the rotor to protect the system in high winds. Although this is still considered a very high-risk option because of the difficulty of building such a blade without excessive weight, it does provide a completely different path to a very high capacity factor (EUI 2003).

Blades

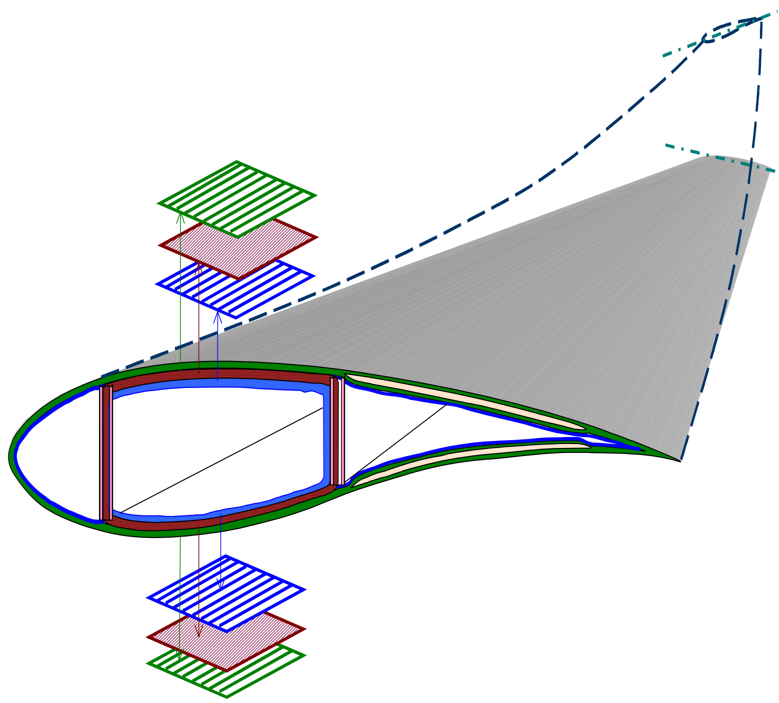
Larger rotors with longer blades sweep a greater area, increasing energy capture. Simply lengthening a blade without changing the fundamental design, however, would make the blade much heavier. In addition, the blade would incur greater structural loads because of its weight and longer moment arm. Blade weight and resultant gravity-induced loads can be controlled by using advanced materials with higher strength-to-weight ratios. Because high-performance materials such as carbon fibers are more expensive, they would be included in the design only when the payoff is maximized. These innovative airfoil shapes hold the promise of maintaining excellent power performance, but have yet to be demonstrated in full-scale operation.

Figure 2-10. Curvature-based twist coupling



One elegant concept is to build directly into the blade structure a passive means of reducing loads. By carefully tailoring the structural properties of the blade using the unique attributes of composite materials, the internal structure of the blade can be built in a way that allows the outer portion of the blade to twist as it bends (Griffin 2001). “Flap-pitch” or “bend-twist” coupling, illustrated in Figure 2-10, is accomplished by orienting the fiberglass and carbon plies within the composite layers of the blade. If properly designed, the resulting twisting changes the angle of attack over much of the blade, reducing the lift as wind gusts begin to load the blade and therefore passively reducing the fatigue loads. Yet another approach to achieving flap-pitch coupling is to build the blade in a curved shape (see Figure 2-11) so that the aerodynamic loads apply a twisting action to the blade, which varies the angle of attack as the aerodynamic loads fluctuate.

Figure 2-11. Twist-flap coupled blade design (material-based twist coupling)



To reduce transportation costs, concepts such as on-site manufacturing and segmented blades are also being explored. It might also be possible to segment molds and move them into temporary buildings close to the site of a major wind installation so that the blades can be made close to, or actually at, the wind site.

Active Controls

Active controls using independent blade pitch and generator torque can be used to reduce tower-top motion, power fluctuations, asymmetric rotor loads, and even individual blade loads. Actuators and controllers already exist that can achieve most of the promised load reductions to enable larger rotors and taller towers. In addition, some researchers have published control algorithms that could achieve the load reductions (Bossanyi 2003). Sensors capable of acting as the eyes and ears of the control system will need to have sufficient longevity to monitor a high-reliability, low-maintenance system. There is also concern that the increased control activity will accelerate wear on the pitch mechanism. Thus, the technical innovation that is essential to enabling some of the most dramatic improvements in performance is not a matter of exploring the unknown, but rather of doing the hard work of mitigating the innovation risk by demonstrating reliable application through prototype testing and demonstration.

Towers

To date, there has been little innovation in the tower, which is one of the more mundane components of a wind installation. But because placing the rotor at a higher elevation is beneficial and because the cost of steel continues to rise rapidly, it is highly likely that this component will be examined more closely in the future, especially for regions of higher than average wind shear.

Because power is related to the cube (the third power) of wind speed, mining upward into these rich veins of higher wind speed potentially has a high payoff—for example, a 10% increase in wind speed produces about a 33% increase in available power. Turbines could sit on even taller towers than those in current use if engineers can figure out how to make them with less steel. Options for using materials other than steel (e.g., carbon fiber) in the tower are being investigated. Such investigations could bear fruit if there are significant adjustments in material costs. Active controls that damp out tower motion might be another enabling technology. Some tower motion controls are already in the research pipeline. New tower erection technologies might play a role in O&M that could also help drive down the system cost of energy (COE) (NREL 2002).

Tower diameters greater than approximately 4 m would incur severe overland transportation cost penalties. Unfortunately, tower diameter and material requirements conflict directly with tower design goals—a larger diameter is beneficial because it spreads out the load and actually requires less material because its walls are thinner. On-site assembly allows for larger diameters but also increases the number of joints and fasteners, raising labor costs as well as concerns about fastener reliability and corrosion. Additionally, tower wall thickness cannot be decreased without limit; engineers must adhere to certain minima to avoid buckling. New tower wall topologies, such as corrugation, can be employed to alleviate the buckling constraint, but taller towers will inevitably cost more.

The main design impact of taller towers is not on the tower itself, but on the dynamics of a system with the bulk of its mass atop a longer, more slender structure. Reducing tower-top weight improves the dynamics of such a flexible system. The tall tower dilemma can be further mitigated with smarter controls that attenuate tower motion by using blade pitch and generator torque control. Although both approaches have been demonstrated, they are still rarely seen in commercial applications.

2

The Drivetrain (Gearbox, Generator, and Power Conversion)

Parasitic losses in generator windings, power electronics, gears and bearings, and other electrical devices are individually quite small. When summed over the entire system, however, these losses add up to significant numbers. Improvements that remove or reduce the fixed losses during low power generation are likely to have an important impact on raising the capacity factor and reducing cost. These improvements could include innovative power-electronic architectures and large-scale use of permanent-magnet generators. Direct-drive systems also meet this goal by eliminating gear losses. Modular (transportable) versions of these large generation systems that are easier to maintain will go a long way toward increasing the productivity of the low-wind portion of the power curve.

Currently, gearbox reliability is a major issue, and gearbox replacement is quite expensive. One solution is a direct-drive power train that entirely eliminates the gearbox. This approach, which was successfully adopted in the 1990s by Enercon-GmbH (Aurich, Germany), is being examined by other turbine manufacturers. A less radical alternative reduces the number of stages in the gearbox from three to two or even one, which enhances reliability by reducing the parts count. The fundamental gearbox topology can also be improved, as Clipper Windpower (Carpinteria, California) did with its highly innovative multiple-drive-path gearbox, which divides mechanical power among four generators (see Figure 2-12). The multiple-drive-path design radically decreases individual gearbox component loads, which reduces gearbox weight and size, eases erection and maintenance demands, and improves reliability by employing inherent redundancies.

The use of rare-earth permanent magnets in generator rotors instead of wound rotors also has several advantages. High energy density eliminates much of the weight associated with copper windings, eliminates problems associated with insulation degradation and shorting, and reduces electrical losses. Rare-earth magnets cannot be subjected to elevated temperatures, however, without permanently degrading magnetic field strength, which imposes corresponding demands on generator cooling reliability. The availability of rare-earth permanent magnets is a potential concern because key raw materials are not available in significant quantities within the United States (see Chapter 3).

Power electronics have already achieved elevated performance and reliability levels, but opportunities for significant improvement remain. New silicon carbide (SiC) devices entering the market could allow operation at higher temperature and higher frequency, while improving reliability, lowering cost, or both. New circuit topologies could furnish better control of power quality, enable higher voltages to be used, and increase overall converter efficiency.

Distributed Energy Systems (Wallingford, Connecticut; formerly Northern Power Systems) has built an advanced prototype power electronics system that will deliver lower losses and conversion costs for permanent-magnet generators (Northern Power Systems 2006). Peregrine Power (Wilsonville, Oregon) has concluded that using SiC devices would reduce power losses, improve reliability, and shrink components by orders of magnitude (Peregrine Power 2006). A study completed by BEW Engineering (San Ramon, California; Behnke, Erdman, and Whitaker Engineering 2006) shows that using medium-voltage power systems for multimegawatt turbines could reduce the cost, weight, and volume of turbine electrical components as well as reduce electrical losses.

Figure 2-12. Clipper Windpower multiple-drive-path gearbox

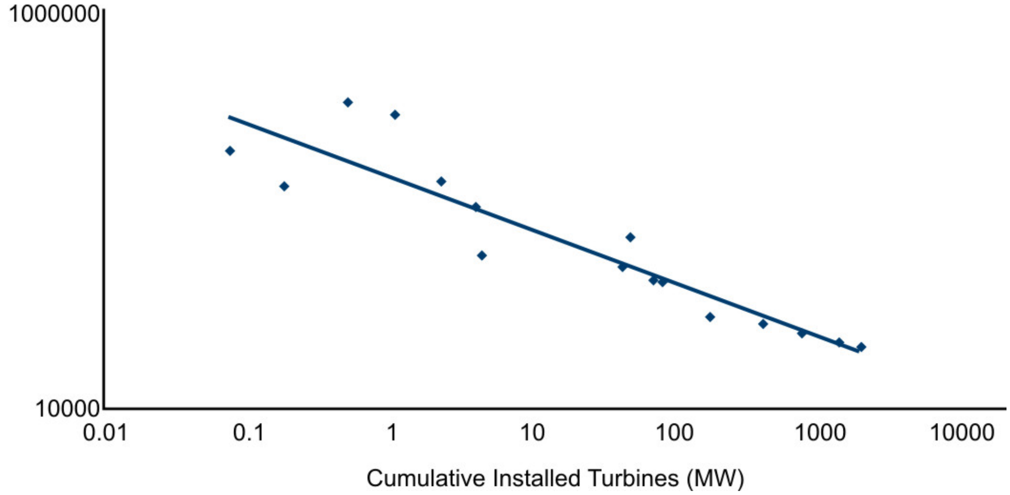
The most dramatic change in the long-term application of wind generation may come from the grid support provided by the wind plant. Future plants will not only support the grid by delivering fault-ride-through capability as well as frequency, voltage, and VAR control, but will also carry a share of power control capability for the grid. Plants can be designed so that they furnish a measure of dispatch capability, carrying out some of the traditional duties of conventional power plants. These plants would be operated below their maximum power rating most of the time and would trade some energy capture for grid ancillary services. Paying for this trade-off will require either a lower capital cost for the hardware, contractual arrangements that will pay for grid services at a high enough rate to offset the energy loss, or optimally, a combination of the two. Wind plants might transition, then, from a simple energy source to a power plant that delivers significant grid support.

2.3.2 Learning-Curve Effect

Progressing along the design and manufacturing learning curve allows engineers to develop technology improvements (such as those listed in Section 2.3.1) and reduce capital costs. The more engineers and manufacturers learn by conducting effective RD&D and producing greater volumes of wind energy equipment, the more proficient and efficient the industry becomes. The learning curve is often measured by calculating the progress ratio, defined as the ratio of the cost after doubling cumulative production to the cost before doubling.

The progress ratio for wind energy from 1984 to 2000 was calculated for the high volume of machines installed in several European countries that experienced a healthy combination of steadily growing manufacturing output, external factors, and research investment during that time. Results show that progress ratio estimates were approximately the same for Denmark (91%), Germany (94%), and Spain (91%) (ISET 2003). At the time this report was written, there was not enough reliable data on U.S.-based manufacturing of wind turbines to determine a U.S. progress ratio. Figure 2-13 shows the data for Spain.

Figure 2-13. Cost of wind turbines delivered from Spain between 1984 and 2000



Note: The Y axis represents cost and is presented in logarithmic units. The data points shown fit the downward-sloping straight line with a correlation coefficient, r^2, of 0.85.

Moving from the current level of installed wind capacity of roughly 12 gigawatts (GW) to the 20% Wind Scenario total of 305 GW will require between four and five doublings of capacity. If the progress ratio of 91% shown in Figure 2-13 continues, prices could drop to about 65% of current costs, a 35% reduction. The low-hanging fruit of cost reduction, however, has already been harvested. The industry has progressed from machines based on designs created without any design tools and built almost entirely by hand to the current state of advanced engineering capability. The assumption in the 20% Wind Scenario is that a 10% reduction in capital cost could accelerate large-scale deployment. In order to achieve this reduction, a progress ratio of only 97.8% is required to produce a learning curve effect of 10% with 4.6 doublings of capacity. With sustained manufacturing growth and technological advancement, there is no technical barrier to achieving 10% capital cost reduction. See Appendix B for further discussion.

2.3.3 The System Benefits of Advanced Technology

A cost study conducted by the U.S. Department of Energy (DOE) Wind Program identified numerous opportunities for technology advancement to reduce the life-cycle COE (Cohen and Schweizer et al. 2008). Based on machine performance and cost, this study used advanced concepts to suggest pathways that integrate the individual contributions from component-level improvements into system-level estimates of the capital cost, annual energy production, reliability, O&M, and balance of station. The results, summarized in Table 2-1, indicate significant potential impacts on annual energy production and capital cost. Changes in annual energy production are equivalent to changes in capacity factor because the turbine rating was fixed. A range of values represents the best, most likely, and least beneficial outcomes.

The Table 2-1 capacity factor improvement of 11% that results from taller towers reflects the increase in wind resources at a hub height of 120 m, conservatively assuming the standard wind shear distribution meteorologists use for open country. Uncertainty in these capacity factor improvements are reflected in the table below. Depending on the success of new tower technology, the added costs could range from 8% to 20%, but there will definitely be an added cost if the tower is the only component in the system that is modified to take the rotor to higher elevations. An advantage would come from a system design in which the tower head mass is significantly reduced with the integration of a rotor and drivetrain that are significantly lighter.

Table 2-1. Areas of potential technology improvement

Technical Area	Potential Advances	Performance and Cost Increments (Best/Expected/Least Percentages)	
		Annual Energy Production	Turbine Capital Cost
Advanced Tower Concepts	• Taller towers in difficult locations • New materials and/or processes • Advanced structures/foundations • Self-erecting, initial, or for service	+11/+11/+11	+8/+12/+20
Advanced (Enlarged) Rotors	• Advanced materials • Improved structural-aero design • Active controls • Passive controls • Higher tip speed/lower acoustics	+35/+25/+10	-6/-3/+3
Reduced Energy Losses and Improved Availability	• Reduced blade soiling losses • Damage-tolerant sensors • Robust control systems • Prognostic maintenance	+7/+5/0	0/0/0
Drivetrain (Gearboxes and Generators and Power Electronics)	• Fewer gear stages or direct-drive • Medium/low speed generators • Distributed gearbox topologies • Permanent-magnet generators • Medium-voltage equipment • Advanced gear tooth profiles • New circuit topologies • New semiconductor devices • New materials (gallium arsenide [GaAs], SiC)	+8/+4/0	-11/-6/+1
Manufacturing and Learning Curve*	• Sustained, incremental design and process improvements • Large-scale manufacturing • Reduced design loads	0/0/0	-27/-13/-3
Totals		+61/+45/+21	-36/-10/+21

*The learning curve results from the NREL report (Cohen and Schweizer et al. 2008) are adjusted from 3.0 doublings in the reference to the 4.6 doublings in the 20% Wind Scenario.

The capital cost reduction shown for the drivetrain components is mainly attributed to the reduced requirements on the structure when lighter components are placed on the tower top. Performance increases as parasitic losses in mechanical and electrical components are reduced. Such components are designed specifically to optimize the performance for wind turbine characteristics. The improvements shown in Table 2-1 are in the single digits, but are not trivial.

Without changing the location of the rotor, energy capture can also be increased by using longer blades to sweep more area. A 10% to 35% increase in capacity factor is produced by 5% to 16% longer blades for the same rated power output. Building these longer blades at an equal or lower cost is a challenge, because blade weight must be capped while turbulence-driven loads remain no greater than what the smaller rotor can handle. With the potential of new structurally efficient airfoils, new materials, passive load attenuation, and active controls, it is estimated that this magnitude of blade growth can be achieved in combination with a modest system cost reduction.

Technology advances can also reduce energy losses in the field. Improved O&M techniques and monitoring capabilities can reduce downtime for repairs and scheduled maintenance. It is also possible to mitigate losses resulting from degradation of performance caused by wear and dirt over time. These improvements are expected to be in the single digits at best, with an approximate 5% improvement in lifetime energy capture.

Doubling the number of manufactured turbines several times over the years will produce a manufacturing learning-curve effect that can also help reduce costs. The learning-curve effects shown in Table 2-1 are limited to manufacturing-related technology improvements and do not reflect issues of component selection and design. As discussed in Section 2.3.2, the learning curve reflects efficiencies driven by volume production and manufacturing experience as well as the infusion of manufacturing technology and practices that encourage more manufacturing-friendly design in the future. Although these changes do not target any added energy capture, they are expected to result in continuous cost reductions. The only adjustment from the NREL reference (Cohen and Schweizer et al. 2008) is that the 20% Wind Scenario by 2030 requires 4.6 doublings of cumulative capacity rather than the 3.0 doublings used in the reference targeted at the year 2012. The most likely 13% cost reduction assumes a conservative progress ratio of 97% per doubling of capacity. However, there are a range of possible outcomes.

The potential technological advances outlined here support the technical feasibility of the 20% Wind Scenario by outlining several possible pathways to a substantial increase in capacity factor accompanied by a modest but double-digit reduction in capital cost.

2.3.4 TARGETED RD&D

While there is an expected value to potential technology improvements, the risk of implementing them has not yet been reduced to the level that allows those improvements to be used in commercial hardware. The issues are well known and offer an opportunity for focused RD&D efforts. In the past, government and industry collaboration has been successful in moving high-risk, high-potential technologies into the marketplace.

One example of such collaboration is the advanced natural gas turbine, which improved the industry efficiency standard—which had been capped at 50%—to almost 60%. DOE invested $100 million in the H-system turbine and General Electric (GE) invested $500 million. Although it was known that higher operating temperatures would lead to higher efficiency, there were no materials for the turbine blades that could withstand the environment. The research program focused on advanced cooling techniques and new alloys to handle combustion that was nearly 300°F hotter. The project produced the world's largest single crystal turbine blades capable of resisting high-temperature cracking. The resulting "H system" gas turbine is 11.89 m long, 4.89 m in diameter, and weighs more than 811,000 lb. Each turbine is expected to save more than $200 million in operating costs over its lifetime (DOE 2000).

A similar example comes from the aviation world. The use of composite materials was known to provide excellent benefits for light-jet airframes, but the certification process to characterize the materials was onerous and expensive. NASA started a program to "reduce the cost of using composites and develop standardized procedures for certifying composite materials" (Brown 2007). The Advanced General Aviation Transport Experiments (AGATE), which began in 1994, solved those problems and opened the door for new composite material technology to be applied to the light-jet application. A technology that would have been too high-risk for the individual companies to develop was bridged into the marketplace through a cooperative RD&D effort by NASA, the Federal Aviation Administration (FAA), industry, and universities. The Adam aircraft A500 turboprop and the A700 very light jet are examples of new products based on this composite technology.

Some might claim that wind technology is a finished product that no longer needs additional RD&D, or that all possible improvements have already been made. The reality is that the technology is substantially less developed than fossil energy technology, which is still being improved after a century of generating electricity. A GE manager who spent a career in the gas turbine business and then transferred to manage the wind turbine business noted the complexity of wind energy technology: "Our respect for wind turbine technology has grown tremendously. The practical side is so complex and forces are so dramatic. We would never have imagined how complex turbines are" (Knight and Harrison 2005).

Already, there is a clear understanding of the materials, controls, and aerodynamics issues that must be resolved to make progress toward greater capacity factors. The combination of reduced capital cost and increased capacity factor will lead to reduced COE. Industry feels the risk of bringing new technology into the marketplace without a full-scale development program is too great and believes sustained RD&D would help reduce risk and help enable the transfer of new technology to the marketplace.

2.4 ADDRESSING TECHNICAL AND FINANCIAL RISKS

Risks tend to lessen industry's desire to invest in wind technology. The wind plant performance track record, in terms of generated revenues and operating costs compared with the estimated revenues used in plant financing, will drive the risk level of future installations. The consequences of these risks directly affect the revenues of owners of wind manufacturing and operating capabilities.

2.4.1 Direct Impacts

When owners of wind manufacturing and operating capabilities directly bear the costs of failure, the impacts are said to be direct. This direct impact on revenue is often caused by:

- **Increasing O&M costs:** As discussed previously and illustrated in Figure 2-9, there is mounting evidence that O&M costs are increasing as wind farms age. Most of these costs are associated with unplanned maintenance or components wearing out before the end of their intended design lives. Some failures can be traced to poor manufacturing or installation quality. Others are caused by design errors, many of which are caused by weaknesses in the technology's state of the art, generally codified by the design process. Figures 2-14 and 2-15 both show steadily rising O&M costs for wind farms installed in the United States in the two decades before the turn of the century, and Figure 2-14 shows the components that have caused these increasing costs. The numbers and costs of component failures increase with time, and the risk to the operators grows accordingly. In Figure 2-14, the solid lines represent expected repairs that may not be completely avoidable, and the dashed lines show potential early failures that can significantly increase risk.
- **Poor availability driven by low reliability:** Energy is not generated while components are being repaired or replaced. Although a single failure of a critical component stops production from only one turbine, such losses can mount up to significant sums of lost revenue.
- **Poor wind plant array efficiency:** If turbines are placed too close together, their wakes interact, which can cause the downwind turbines to perform poorly. But if they are placed too far apart, land and plant maintenance costs increase.

Figure 2-14. Unplanned repair cost, likely sources, and risk of failure with wind plant age

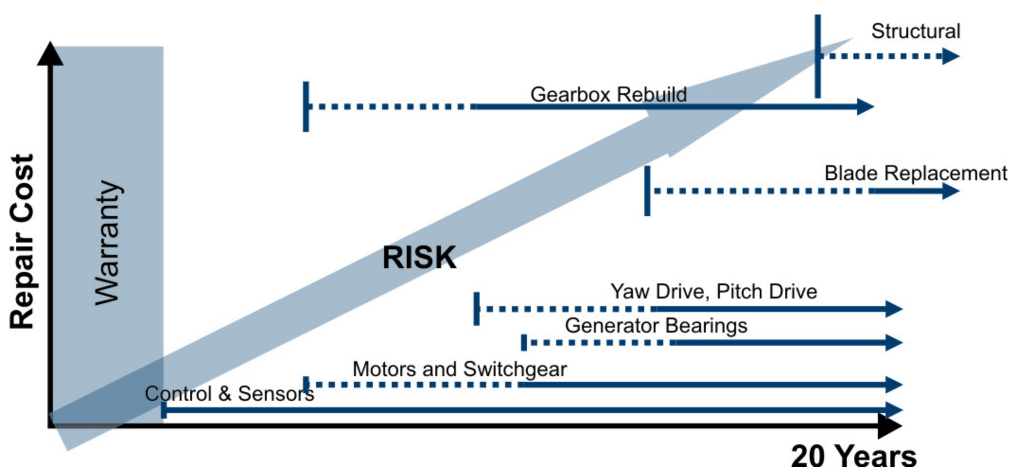
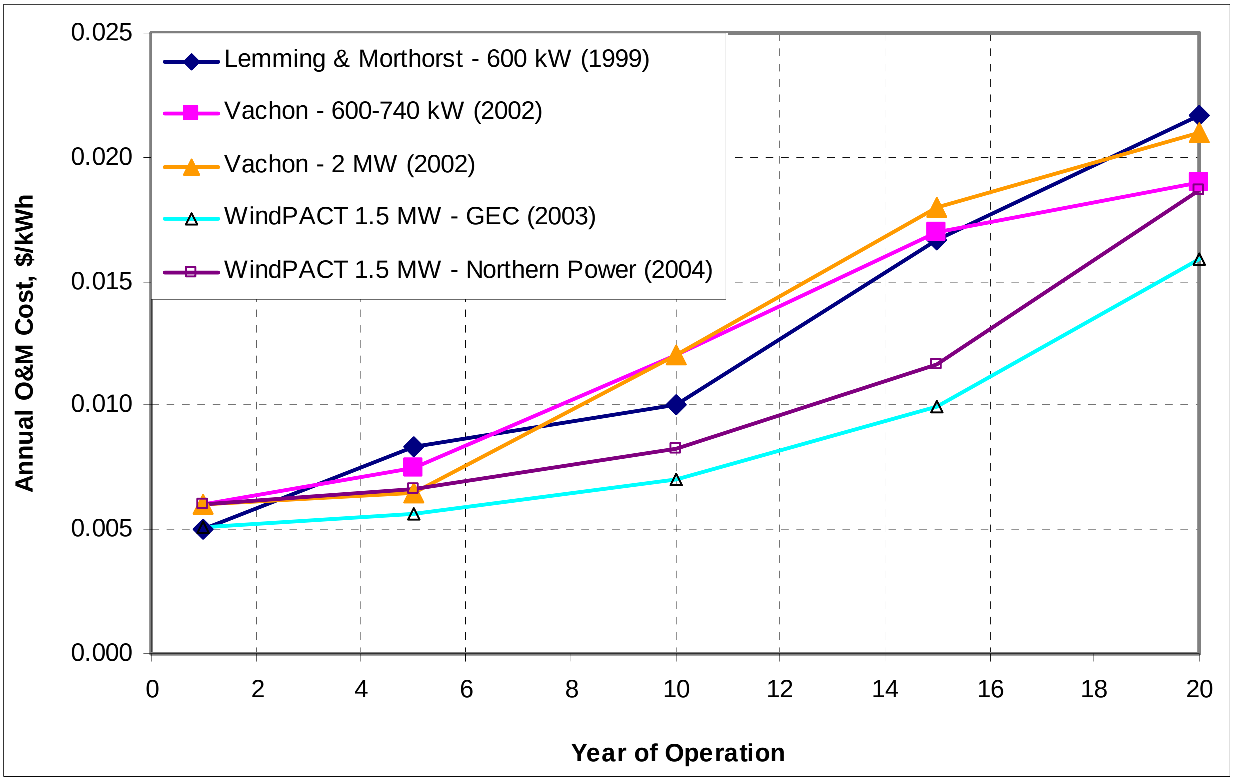


Figure 2-15. Average O&M costs of wind farms in the United States



2.4.2 Indirect Impacts

Although the wind industry has achieved high levels of wind plant availability and reliability, unpredictable or unreliable performance would threaten the credibility of this emerging technology in the eyes of financial institutions. The consequences of real or perceived reliability problems would extend beyond the direct cost to the plant owners. These consequences on the continued growth of investment in wind could include:

- **Increased cost of insurance and financing:** Low interest rates and long-term loans are critical to financing power plants that are loaded with upfront capital costs. Each financial institution will assess the risk of investing in wind energy and charge according to those risks. If wind power loses credibility, these insurance and financing costs could increase.
- **Slowing or stopping development:** Lost confidence contributed to the halt of development in the United States in the late 1980s through the early 1990s. Development did not start again until the robust European market supported the technology improvements necessary to reestablish confidence in reliable European turbines. As a result, the current industry is dominated by European wind turbine companies. Active technical supporters of RD&D must anticipate and resolve problems before they threaten industry development.
- **Loss of public support:** If wind power installations do not operate continuously and reliably, the public might be easily convinced that

renewable energy is not a viable source of energy. The public's confidence in the technology is crucial. Without public support, partnerships working toward a new wind industry future cannot be successful.

2.4.3 Risk Mitigation Through Certification, Validation, and Performance Monitoring

To reduce risk, the wind industry requires turbines to adhere to international standards. These standards, which represent the collective experience of the industry's leading experts, imply a well-developed design process that relies on the most advanced design tools, testing for verification, and disciplined quality control.

Certification

Certification involves high-level, third-party technical audits of a manufacturer's design development. It includes a detailed review of design analyses, material selections, dynamic modeling, and component test results. The wind industry recognizes that analytical reviews are not sufficient to capture weaknesses in the design process. Therefore, consensus standard developers also require full-scale testing of blades, gearboxes, and the complete system prototype (see "Industry Standards" sidebar).

Actively complying with these standards encourages investment in wind energy by ensuring that turbines reliably achieve the maximum energy extraction needed to expand the industry.

> **Industry Standards**
>
> The American National Standards Institute (ANSI) has designated the American Wind Energy Association (AWEA) as the lead organization for the development and publication of industry consensus standards for wind energy equipment and services in the United States. AWEA also participates in the development of international wind energy standards through its representation on the International Electrotechnical Commission (IEC) TC-88 Subcommittee. Information on these standards can be accessed on AWEA's Web site (http://www.awea.org/standards).

Full-Scale Testing

Testing standards were drafted to ensure that accredited third-party laboratories are conducting tests consistently. These tests reveal many design and manufacturing deficiencies that are beyond detection by analytical tools. They also provide the final verification that the design process has worked and give the financial community the confidence needed to invest in a turbine model.

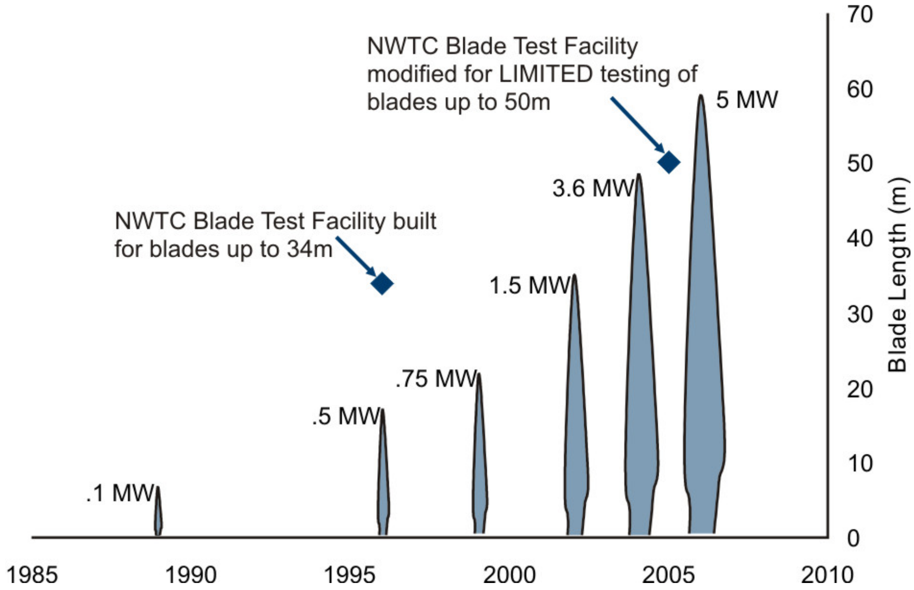
Full-scale test facilities and trained test engineers capable of conducting full-scale tests are rare. The facilities must have equipment capable of applying tremendous loads that mimic the turbulence loading that wind applies over the entire life of the blade or gearbox. Full-scale prototype tests are conducted in the field at locations with severe wind conditions. Extensive instrumentation is applied to the machine, according to a test plan prescribed by international standards, and comprehensive data are recorded over a specified range of operating conditions. These data give the certification agent a means for verifying the accuracy of the design's analytical basis. The industry and financial communities depend on these facilities and skilled test engineers to support all new turbine component development.

As turbines grow larger and more products come on the market, test facilities must also grow and become more efficient. New blades are reaching 50 m in length, and the United States has no facilities that can test blades longer than 50 m. Furthermore, domestic dynamometer facilities capable of testing gearboxes or new drivetrains are limited in capacity to 1.5 MW. The limited availability of facilities and qualified test engineers increases the deployment risk of new machines that are not subjected to the rigors of current performance validation in accredited facilities.

At full-scale facilities, it is also difficult to conduct tests accurately and capture the operating conditions that are important to verify the machine's reliability. These tests are expensive to conduct and accreditation is expensive to maintain for several reasons. First, the scale of the components is one of the largest of any commercial industry. Because blades are approaching sizes of half the length of a football field and can weigh more than a 12.2 m yacht, they are very difficult and expensive to transport on major highways. The magnitude of torque applied to the drivetrains for testing is among the largest of any piece of rotating equipment ever constructed. Figure 2-16 shows the largest blades being built and the approximate dates when U.S. blade test facilities were built to accommodate their testing.

Although it is very expensive for each manufacturer to develop and maintain

Figure 2-16. Blade growth and startup dates for U.S. blade test facilities



facilities of this scale for its own certification testing needs, without these facilities, rapid technological progress will be accompanied by high innovation risk. Wind energy history has proven that these kinds of tests are crucial for the industry's success and the financial community's confidence. These tests, then, are an essential element of any risk mitigation strategy.

Performance Monitoring and O&M

One of the main elements of power plant management is strategic monitoring of reliability. Other industries have established anonymous databases that serve to benchmark their reliability and performance, giving operators both the ability to recognize a drop in reliability and the data they need to determine the source of low reliability. The wind industry needs such a strategically designed database, which would give O&M managers the tools to recognize and pinpoint drops in reliability, along with a way to collectively resolve technical problems. Reliability databases are an integral part of more sophisticated O&M management tools. Stiesdal and Madsen (2005) describe how databases can be used for managing O&M and improving future designs.

In mature industries, O&M management tools are available to help maximize maintenance efficiency. Achieving this efficiency is a key factor in minimizing the COE and maximizing the life of wind plants, thereby increasing investor confidence. Unlike central generation facilities, wind plants require maintenance strategies that minimize human attention and maximize remote health monitoring and automated fault data diagnosis. This requires intimate knowledge of healthy plant operating characteristics and an ability to recognize the characteristics of very complex faults that might be unique to a specific wind plant. Such tools do not currently exist for the wind industry, and their development will require RD&D to study wind plant systems interacting with complex atmospheric conditions and to model the interactions. The resultant deeper understanding will allow expert systems to be developed, systems that will aid operators in their quest to maximize plant performance and minimize operating costs through risk mitigation. These systems will also produce valuable data for improving the next generation of turbine designs.

2.5 Offshore Wind Technology

Offshore wind energy installations have a broadly dispersed, abundant resource and the economic potential for cost competitiveness that would allow them to make a large impact in meeting the future energy needs of the United States (Musial 2007). Of the contiguous 48 states, 28 have a coastal boundary. U.S. electric use data show that these same states use 78% of the nation’s electricity (EIA 2006). Of these 28 states, only 6 have a sufficient land-based wind energy resource to meet more than 20% of their electric requirements through wind power. If shallow water offshore potential (less than 30 m in depth) is included in the wind resource mix, though, 26 of the 28 states would have the wind resources to meet at least 20% of their electric needs, with many states having sufficient offshore wind resources to meet 100% of their electric needs (Musial 2007). For most coastal states, offshore wind resources are the only indigenous energy source capable of making a significant energy contribution. In many congested energy-constrained regions, offshore wind plants might be necessary to supplement growing demand and dwindling fossil supplies.

Twenty-six offshore wind projects with an installed capacity of roughly 1,200 MW now operate in Europe. Most of these projects were installed in water less than 22 m deep. One demonstration project in Scotland is installed in water at a depth of 45 m. Although some projects have been hampered by construction overruns and higher-than-expected maintenance requirements, projections show strong growth in many European Union (EU) markets. For example, it is estimated that offshore wind capacity in the United Kingdom will grow by 8,000 MW by 2015. Similarly, German offshore development is expected to reach 5,600 MW by 2014 (BSH; BWEA).

In the United States, nine offshore project proposals in state and federal waters are in various stages of development. Proposed projects on the Outer Continental Shelf are under the jurisdiction of the Minerals Management Service (MMS) with their authority established by the Energy Policy Act (EPAct) of 2005 (MMS). Several states are pursuing competitive solicitations for offshore wind projects approval.

2.5.1 Cost of Energy

The current installed capital cost of offshore projects is estimated in the range of $2,400 to $5,000 per kW (Black & Veatch 2007; Pace Global 2007). Because offshore wind energy tends to take advantage of extensive land-based experience and mature offshore oil and gas practices, offshore cost reductions are not expected to be as great as land-based reductions spanning the past two decades. However, offshore wind technology is considerably less mature than land-based wind energy, so it does have significant potential for future cost reduction. These cost reductions are achievable through technology development and innovation, implementation and customization of offshore oil and gas practices, and learning-curve reductions that take advantage of more efficient manufacturing and deployment processes and procedures.

2.5.2 Current Technology

Today's baseline technology for offshore wind turbines is essentially a version of the standard land-based turbine adapted to the marine environment. Although turbines of up to 5 MW have been installed, most recent orders from Vestas (Randers, Denmark) and Siemens (Munich, Germany), the two leading suppliers of offshore wind turbines, range from 2.0 MW to 3.6 MW.

The architecture of the baseline offshore turbine and drivetrain comprises a three-bladed upwind rotor, typically 90 m to 107 m in diameter. Tip speeds of offshore turbines are slightly higher than those of land-based turbines, which have speeds of 80 m/s or more. The drivetrain consists of a gearbox generally run with variable-speed torque control that can achieve generator speeds between 1,000 and 1,800 rpm. The offshore tower height is generally 80 m, which is lower than that of land-based towers, because wind shear profiles are less steep, tempering the advantage of tower height.

The offshore foundation system baseline technology uses monopiles at nominal water depths of 20 m. Monopiles are large steel tubes with a wall thickness of up to 60 mm and diameters of 6 m. The embedment depth varies with soil type, but a typical North Sea installation must be embedded 25 m to 30 m below the mud line. The monopile extends above the surface where a transition piece with a flange to fasten the tower is leveled and grouted. Its foundation requires a specific class of installation equipment for driving the pile into the seabed and lifting the turbine and tower into place. Mobilization of the infrastructure and logistical support for a large offshore wind plant accounts for a significant portion of the system cost.

Turbines in offshore applications are arranged in arrays that take advantage of the prevailing wind conditions measured at the site. Turbines are spaced to minimize aggregate power plant energy losses, interior plant turbulence, and the cost of cabling between turbines.

The power grid connects the output from each turbine, where turbine transformers step up the generator and the power electronics voltage to a distribution voltage of about 34 kilovolts (kV). The distribution system collects the power from each turbine at a central substation where the voltage is stepped up and transmitted to shore through a number of buried, high-voltage subsea cables. A shore-based interconnection point might be used to step up the voltage again before connecting to the power grid.

Shallow water wind turbine projects have been proposed and could be followed by transitional and finally deepwater turbines. These paths should not be considered as mutually exclusive choices. Because there is a high degree of interdependence among them, they should be considered a sequence of development that builds from a shallow water foundation of experience and knowledge to the complexities of deeper water.

2.5.3 Technology Needs and Potential Improvements

Offshore, wind turbine cost represents only one-third of the total installed cost of the wind project, whereas on land, the turbine cost represents more than half of the total installed cost. To lower costs for offshore wind, the focus must be on lowering the balance-of-station costs. These costs, which include those for foundations, electrical grids, O&M, and installation and staging costs, dominate the system COE. Turbine improvements that make turbines more reliable, more maintainable, more rugged, and larger, will still be needed to achieve cost goals. Although none of these improvements are likely to lower turbine costs, the net result will lower overall system costs.

Commercialization of offshore wind energy faces many technical, regulatory, socioeconomic, and political barriers, some of which may be mitigated through targeted short- and long-range RD&D efforts. Short-term research addresses impediments that prevent initial industry projects from proceeding and helps sharpen the focus for long-term research. Long-term research involves a more complex development process resulting in improvements that can help lower offshore life-cycle system costs.

Short-Term RD&D Options

Conducting research that will lead to more rapid deployment of offshore turbines should be an upfront priority for industry. This research should address obstacles to today's projects, and could include the following tasks:

- **Define offshore resource exclusion zones:** A geographically based exclusion study using geographic information system (GIS) land use overlays would more accurately account for all existing and future marine uses and sensitive areas. This type of exclusion study could be part of a regional programmatic environmental impact statement and is necessary for a full assessment of the offshore resource (Dhanju, Whitaker, and Kempton 2006). Currently, developers bear the burden of siting during a pre-permitting phase with very little official guidance. This activity should be a jointly funded industry project conducted on a regional basis.
- **Develop certification methods and standards:** MMS has been authorized to define the structural safety standards for offshore wind turbines on the OCS. Technical research, analysis, and testing are needed to build confidence that safety will be adequate, and to prevent overcautiousness that will increase costs unnecessarily. Developing these standards will require a complete evaluation and harmonization of the existing offshore wind standards and the American Petroleum Institute (API) offshore oil and gas standards. MMS is currently determining the most relevant standards.
- **Develop design codes, tools, and methods:** The design tools that the wind industry uses today have been developed and validated for

land-based utility-scale turbines, and the maturity and reliability of the tools have led to significantly higher confidence in today's wind turbines. By comparison, offshore design tools are relatively immature. The development of accurate offshore computer codes to predict the dynamic forces and motions acting on turbines deployed at sea is essential for moving into deeper water. One major challenge is predicting loads and the resulting dynamic responses of the wind turbine's support structure when it is subjected to combined wave and wind loading. These offshore design tools must be validated to ensure that they can deal with the combined dominance of simultaneous wind and wave load spectra, which is a unique problem for offshore wind installations. Floating system analysis must be able to account for additional turbine motions as well as the dynamic characterization of mooring lines.

- **Site turbines and configure arrays:** The configuration and spacing of wind turbines within an array have a marked effect on power production from the aggregate wind plant, as well as for each individual turbine. Uncertainties in power production represent a large economic risk factor for offshore development. Offshore wind plants can lose more than 10% of their energy to array losses, but improvements in array layout and array optimization models could deliver substantial recovery (SEAWIND 2003). Atmospheric boundary layer interaction with the turbine wakes can affect both energy capture and plant-generated turbulence. Accurate characterization of the atmospheric boundary layer behavior and more accurate wake models will be essential for designing turbines that can withstand offshore wind plant turbulence. Wind plant design tools that are able to characterize turbulence generated by wind plants under a wide range of conditions are likely necessary.
- **Develop hybrid wind-speed databases:** Wind, sea-surface temperatures, and other weather data are housed in numerous satellite databases available from the National Oceanic and Atmospheric Administration (NOAA), NASA, the National Weather Service (NWS), and other government agencies. These data can be combined to supplement the characterization of coastal and offshore wind regimes (Hasager et al. 2005). The limitations and availability of existing offshore data must be understood. Application of these data to improve the accuracy of offshore wind maps will also be important.

Long-Term R&D Options

Long-term research generally requires hardware development and capital investment, and it must take a complex development path that begins early enough for mature technology to be ready when needed. Most long-term research areas relate to lowering offshore life-cycle system costs. These areas are subdivided into infrastructure and turbine-specific needs. Infrastructure to support offshore wind development represents a major cost element. Because this is a relatively new technology path, there are major opportunities for reducing the cost impacts. Although land-based wind turbine designs can generally be used for offshore deployment, the offshore environment will impose special requirements on turbines. These requirements must be taken into account to optimize offshore deployment. Areas where industry should focus efforts include:

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- **Minimize work at sea:** There are many opportunities to lower project costs by reallocating the balance between work done on land and at sea. The portion of labor devoted to project O&M, land-based installation and assembly, and remote inspections and diagnostics can be rebalanced with upfront capital enhancements, such as higher quality assurance, more qualification testing, and reliable designs. This rebalancing might enable a significant life-cycle cost reduction by shifting the way wind projects are designed, planned, and managed.
- **Enhance manufacturing, installation and deployment strategies:** New manufacturing processes and improvements in existing processes that reduce labor and material usage and improve part quality have high potential for reducing costs in offshore installations. Offshore wind turbines and components could be constructed and assembled in or near seaport facilities that allow easy access from the production area to the installation site, eliminating the necessity of shipping large components over inland roadways. Fabrication facilities must be strategically located for mass-production, land-based assembly, and for rapid deployment with minimal dependence on large vessels. Offshore system designs that can be floated out and installed without large cranes can reduce costs significantly. New strategies should be integrated into the turbine design process at an early stage (Lindvig 2005; Poulsen and Skjærbæk 2005).
- **Incorporate offshore service and accessibility features:** To manage O&M, predict weather windows, minimize downtime, and reduce the equipment needed for up-tower repairs, operators should be equipped with remote, intelligent, turbine condition monitoring and self-diagnostic systems. These systems can alert operators to the need for operational changes, or enable them to schedule maintenance at the most opportune times. A warning about an incipient failure can alert the operators to replace or repair a component before it does significant damage to the system or leaves the machine inoperable for an extended period of time. More accurate weather forecasting will also become a major contributor in optimizing service schedules for lower cost.
- **Develop low-cost foundations, anchors, and moorings:** Current shallow-water foundations have already reached a practical depth limit of 30 m, and anchor systems beyond that are derived from conservative and expensive oil and gas design practices. Cost-saving opportunities arise for wind power plants in deeper water with both fixed-bottom and floating turbine foundations, as well as for existing shallow-water designs in which value-engineering cost reductions can be achieved. Fixed-bottom systems comprising rigid lightweight substructures, automated mass-production fabrication facilities, and integrated mooring and piling deployment systems that minimize dependence on large sea vessels are possible low-cost options. Floating platforms will require a new generation of mooring designs that can be mass produced and easily installed.
- **Use resource modeling and remote profiling systems:** Offshore winds are much more difficult to characterize than winds over land. Analytical models are essential for managing risk during the initial

siting of offshore projects, but are not very useful by themselves for micrositing (Jimenez et al. 2005). Alternative methods are needed to measure wind speed and wind shear profiles up to elevations where wind turbines operate. This will require new equipment such as sonic detection and ranging (SODAR), light detection and ranging (LIDAR), and coastal RADAR-based systems that must be adapted to measure offshore wind from more stable buoy systems or from fixed bases. Some systems are currently under development but have not yet been proven (Antoniou et al. 2006). The results of an RD&D measurement program on commercial offshore projects could generate enough confidence in these systems to eliminate the requirement for a meteorological tower.

- **Increase offshore turbine reliability:** The current offshore service record is mixed, and as such, is a large contributor to high risk. A new balance between initial capital investment and long-term operating costs must be established for offshore systems. This new balance will have a significant impact on COE. Offshore turbine designs must place a higher premium on reliability and anticipation of on-site repairs than their land-based counterparts. Emphasis should be placed on avoiding large maintenance events that require expensive and specialized equipment. This can be done by identifying the root causes of component failures, understanding the frequency and cost of each event, and appropriately implementing design improvements (Stiesdal and Madsen 2005). Design tools, quality control, testing, and inspection will need heightened emphasis. Blade designers must consider strategies to offset the impacts of marine moisture, corrosion, and extreme weather. In higher latitudes, designers must also account for ice flows and ice accretion on the blades. Research that improves land-based wind turbine reliability now will have a direct impact on the reliability of future offshore machines.

- **Assess the potential of ultra-large offshore turbines:** Land-based turbines may have reached a size plateau because of transportation and erection limits. Further size growth in wind turbines will largely be pushed by requirements unique to offshore turbine development. According to a report on the EU-funded UpWind project, “Within a few years, wind turbines will have a rotor diameter of more than 150 m and a typical size of 8 MW–10 MW” (Risø National Laboratory 2005). The UpWind project plans to develop design tools to optimize large wind turbine components, including rotor blades, gearboxes, and other systems that must perform in large offshore wind plants. New size-enabling technologies will be required to push wind turbines beyond the scaling limits that constrain the current fleet. These technologies include lightweight composite materials and composite manufacturing, lightweight drivetrains, modular pole direct-drive generators, hybrid space frame towers, and large gearbox and bearing designs that are tolerant of slower speeds and larger scales. All of the weight-reducing features of the taller land-based tower systems will have an even greater value for very large offshore machines (Risø National Laboratory 2005).

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RD&D Summary

The advancement of offshore technology will require the development of infrastructure and technologies that are substantially different from those employed in land-based installations. In addition, these advances would need to be tailored to U.S. offshore requirements, which differ from those in the European North Sea environment. Government leadership could accelerate baseline research and technology development to demonstrate feasibility, mitigate risk, and reduce regulatory and environmental barriers. Private U.S. energy companies need to take the technical and financial steps to initiate near-term development of offshore wind power technologies and bring them to sufficient maturity for large-scale deployment. Musial and Ram (2007) and Bywaters and colleagues (2005) present more detailed analyses of actions for offshore development.

2.6 Distributed Wind Technology

Distributed wind technology (DWT) applications refer to turbine installations on the customer side of the utility meter. These machines range in size from less than 1 kW to multimegawatt, utility-scale machines, and are used to offset electricity consumption at the retail rate. Because the WinDS deployment analysis does not currently segregate DWT from utility deployment, DWT applications are part of the land-based deployment estimates in the 20% Wind Energy Scenario.

Historically, DWT has been synonymous with small machines. The DWT market in the 1990s focused on battery charging for off-grid homes, remote telecommunications sites, and international village power applications. In 2000, the industry found a growing domestic market for behind-the-meter wind power, including small machines for residential and small farm applications and multimegawatt-scale machines for larger agricultural, commercial, industrial, and public facility applications. Although utility-scale DWT requirements are not distinguishable from those for other large-scale turbines, small machines have unique operating requirements that warrant further discussion.

2.6.1 Small Turbine Technology

Until recently, three-bladed upwind designs using tail vanes for passive yaw control dominated small wind turbine technology (turbines rated at less than 10 kW). Furling, or turning the machine sideways to the wind with a mechanical linkage, was almost universally used for rotor overspeed control. Drivetrains were direct-drive, permanent-magnet alternators with variable-speed operation. Many of these installations were isolated from the grid. Today, there is an emerging technology trend toward grid-connected applications and nonfurling designs. U.S. manufacturers are world leaders in small wind systems rated at 100 kW or less, in terms of both market and technology.

Turbine technology begins the transition from small to large systems between 20 kW and 100 kW. Bergey Windpower (Norman, Oklahoma) offers a 50 kW turbine that uses technology commonly found in smaller machines, including furling, pultruded blades, a direct-drive, permanent-magnet alternator, and a tail vane for yaw control. Distributed Energy Systems offers a 100 kW turbine that uses a direct-drive, variable-speed synchronous generator. Although most wind turbines in the 100 kW range have features common to utility-scale turbines, including gearboxes, mechanical brakes, induction generators, and upwind rotors with active yaw control, Endurance Windpower (Spanish Fork, Utah) offers a 5 kW turbine with such characteristics.

For small DWT applications, reliability and acoustic emissions are the prominent issues. Installations usually consist of a single turbine. Installations may also be widely scattered. So simplicity in design, ease of repair, and long maintenance and inspection intervals are important. Because DWT applications are usually close to workplaces or residences, limiting sound emissions is critical for market acceptance and zoning approvals. DWT applications are also usually located in areas with low wind speeds that are unsuitable for utility-scale applications, so DWT places a premium on low-wind-speed technologies.

The cost per kW of DWT turbines is inversely proportionate with turbine size. Small-scale DWT installation costs are always higher than those for utility-scale installations because the construction effort cannot be amortized over a large number of turbines. For a 1 kW system, hardware costs alone can be as high as $5,000 to $7,000/kW. Installation costs vary widely because of site-specific factors such as zoning and/or permitting costs, interconnection fees, balance-of-station costs, shipping, and the extent of do-it-yourself participation. Five-year warranties are now the industry standard for small wind turbines, although it is not yet known how this contributes to turbine cost. The higher costs of this technology are partially offset by the ability to compete with retail electricity rates. In addition, small turbines can be connected directly to the electric distribution system, eliminating the need for an expensive interconnection between the substation and the transmission.

Tower and foundation costs make up a larger portion of DWT installed cost, especially for wind turbines of less than 20 kW. Utility-scale turbines commonly use tapered tubular steel towers. However, for small wind turbines, multiple types, sources, and heights of towers are available.

2.6.2 Technology Trends

Recent significant developments in DWT systems less than 20 kW include the following:

- **Alternative power and load control strategies:** Furling inherently increases sound levels because the cross-wind operation creates a helicopter-type chopping noise. Aerodynamic models available today cannot accurately predict the rotor loads in the highly skewed and unsteady flows that occur during the furling process, complicating design and analysis. Alternative development approaches include soft-stall rotor-speed control, constant-speed operation, variable-pitch blades, hinged blades, mechanical brakes, and centrifugally actuated blade tips. These concepts offer safer, quieter turbines that respond more predictably to high winds, gusts, and sudden wind direction changes.
- **Advanced blade manufacturing methods:** Blades for small turbines have been made primarily of fiberglass by hand lay-up manufacturing or pultrusion. The industry is now pursuing alternative manufacturing techniques, including injection, compression, and reaction injection molding. These methods often provide shorter fabrication time, lower parts costs, and increased repeatability and uniformity, although the tooling costs are typically higher.

- **Rare-earth permanent magnets:** Ferrite magnets have long been the staple in permanent-magnet generators for small wind turbines. Rare-earth permanent magnets are now taking over the market with Asian suppliers offering superior magnetic properties and a steady decline in price. This enables more compact and lighter weight generator designs.
- **Reduced generator cogging:** Concepts for generators with reduced cogging torque (the force needed to initiate generator rotation) are showing promise to reduce cut-in wind speeds. This is an important advancement to improve low-wind-speed turbine performance and increase the number of sites where installation is economical.
- **Induction generators:** Small turbine designs that use induction generators are under development. This approach, common in the early 1980s, avoids the use of power electronics that increase cost and complexity, and reduce reliability.
- **Grid-connected inverters:** Inverters used in the photovoltaics market are being adapted for use with wind turbines. Turbine-specific inverters are also appearing in both single- and three-phase configurations. Another new trend is obtaining certification of most inverters by Underwriters Laboratories and others for compliance with national interconnection standards.
- **Reduced rotor speeds:** To reduce sound emissions, turbine designs with lower tip-speed ratios and lower peak-rotor speeds are being pursued.
- **Design standards and certification:** The industry is increasing the use of consensus standards in its turbine design efforts for machines with rotor swept areas under 200 m^2 (about 65 kW rated power). In particular, IEC Standard 61400-2 Wind Turbines – Part 2: Design Requirements of Small Wind Turbines. Currently, however, a limited number of wind turbines have been certified in compliance with this standard because of the high cost of the certification process. To address this barrier, a Small Wind Certification Council has been formed in North America to certify that small wind turbines meet the requirements of the draft AWEA standard that is based on the IEC standard (AWEA 1996–2007).

2.7 SUMMARY OF WIND TECHNOLOGY DEVELOPMENT NEEDS

Wind technology must continue to evolve if wind power is to contribute more than a few percentage points of total U.S. electrical demand. Fortunately, no major technology breakthroughs in land-based wind technology are needed to enable a broad geographic penetration of wind power into the electric grid. However, there are other substantial challenges (such as transmission and siting) and significant costs associated with increased penetration, which are discussed in other chapters of this report. No improvement in cost or efficiency for a single component can achieve the cost reductions or improved capacity factor that system-level advances can achieve.

The wind capacity factor can be increased by enlarging rotors and installing them on taller towers. This would require advanced materials, controls, and power systems that can significantly reduce the weight of major components. Capital costs would also be brought down by the manufacturing learning curve that is associated with continued technology advancement and by a nearly fivefold doubling of installed capacity.

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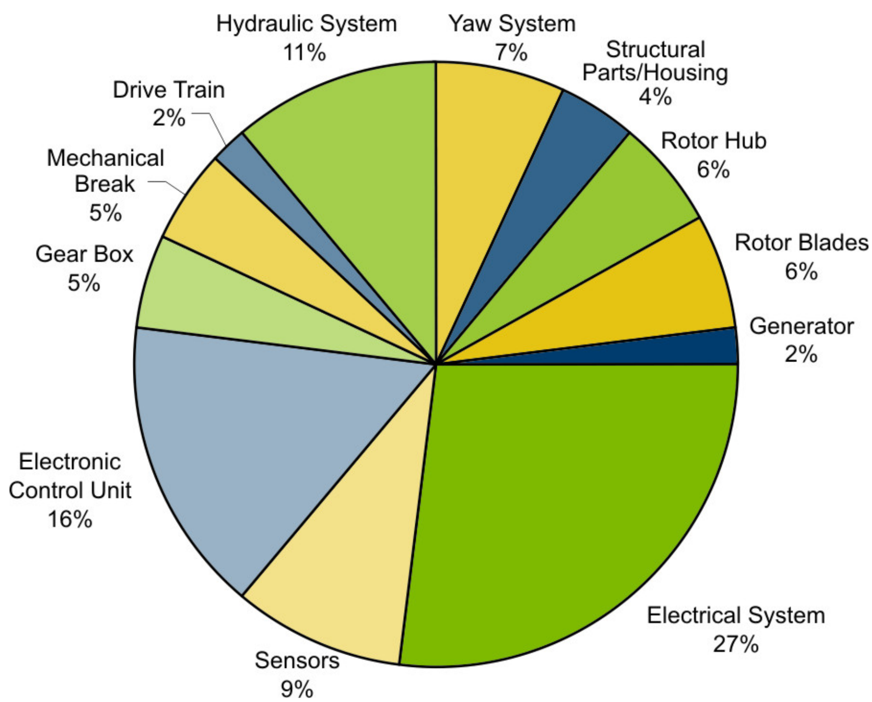
The technology development required to make offshore wind a viable option poses a substantial potential risk. Offshore wind deployment represents a significant fraction of the total wind deployment necessary for 20% wind energy by 2030. Today's European shallow-water technology is still too expensive and too difficult to site in U.S. waters. Deepwater deployment would eliminate visual esthetics concerns, but the necessary technologies have yet to be developed, and the potential environmental impacts have yet to be evaluated. To establish the offshore option, work is needed to develop analysis methods, evaluate technology pathways, and field offshore prototypes.

Figure 2-17. Types of repairs on wind turbines from 2.5 kW to 1.5 MW



Today's market success is the product of a combination of technology achievement and supportive public policy. A 20% Wind Scenario would require additional land-based technology improvements and a substantial development of offshore technology. The needed cost and performance improvements could be achieved with innovative changes in existing architectures that incorporate novel advances in materials, design approaches, control strategies, and manufacturing processes. Risks are mitigated with standards that produce reliable equipment and full-scale testing that ensures the machinery meets the design requirements.

The 20% Wind Scenario assumes a robust technology that will produce cost-competitive generation with continued R&D investment leading to capital cost reduction and performance improvement. Areas where industry can focus RD&D efforts include those which require the most frequent repairs (see Figure 2-17). Such industry efforts, along with government-supported RD&D efforts, will support progress toward achieving two primary wind technology objectives:

- Increasing capacity factors by placing larger rotors on taller towers (this can be achieved economically only by using lighter components and load-mitigating rotors that reduce the integrated tower-top mass and structural loads; reducing parasitic losses throughout the system can also make gains possible), developing advanced controls, and improving power systems.

- Reducing the capital cost with steady learning-curve improvements driven by innovative manufacturing improvements and a nearly fivefold doubling of installed capacity

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Chapter 3. Manufacturing, Materials, and Resources

A 20% Wind Energy Scenario would support expansion of domestic manufacturing and related employment. Production of several key materials for wind turbines would require substantial but achievable growth.

Stakeholders and decision makers need to know whether the effort to achieve a generation mix with 20% wind energy by 2030 might be constrained by raw materials availability, manufacturing capability, or labor availability. This chapter examines the adequacy of these critical resources.

Over the past five years, the wind industry in the United States has grown by an average of 22% annually. In 2006 alone, America’s wind power generating capacity increased by 27%.

The U.S. wind energy industry invested approximately $4 billion to build 2,454 MW of new generating capacity in 2006, making wind the second largest source of new power generation in the nation—surpassed only by natural gas—for the second year in a row. Recently installed wind farms increased cumulative installed U.S. wind energy capacity to 13,884 MW—well above the 10,000 MW milestone reached in August 2006 (AWEA 2007). On average, 1 MW of wind power produces enough electricity to power 250 to 300 U.S. homes.

Based on estimates released by the U.S. Department of Energy (DOE) Energy Information Administration (EIA 2006), annual electricity consumption in the United States is expected to grow at a rate of 1.3% annually—from 3.899 billion megawatt-hours (MWh) in 2006 to about 5.368 billion MWh in 2030. Although wind energy supplied approximately 0.8% of the total electricity in 2006, more and larger wind turbines can help to meet a growing demand for electricity. (See the Glossary in Appendix E for explanations of wind energy capacity and measurement units.)

The most common large turbines currently in use have a rated capacity of between 1 MW and 3 MW, with rotor diameters between 60 m and 90 m, tower heights between 60 m and 100 m, and capacity factors between 30% and 40% (capacity factor is an indicator of annual energy production). Although currently installed machines are expected to operate through 2030, larger turbines (with capacity factors that increase over time, as discussed in Chapter 2) are expected to become more common as offshore technology advances are transferred to land-based turbines. These larger turbines could reach rated power between 4 MW and 6 MW with capacity factors between 40% and 50%.

To estimate the raw materials and investments needed to support the 20% Wind Scenario, industry leaders have assumed that most of the wind turbines used in the next two to three decades will be in the 1 MW to 3 MW class, with a modest contribution of the larger-sized machines (see Chapter 2). Today, approximately 2,000 turbines are installed each year, but that figure is expected to rise and to level out at about 7,000 turbines per year by 2017.

3

3.1 RAW MATERIALS REQUIREMENTS

Wind turbines are built in many sizes and configurations, with the larger sizes utilizing a wide range of materials. Reducing the weight and cost of the turbines is key to making wind energy competitive with other power sources. Throughout the next few decades, business opportunities are expected to expand in wind turbine components and materials manufacturing. To reach the high levels of wind energy associated with the 20% Wind Scenario, materials usage will also need to increase considerably, even as new technologies that improve component performance are introduced.

To estimate the raw materials required for the 20% Wind Scenario, this analysis focuses on the most important materials used in building a wind turbine today (such as steel and aluminum) and on main turbine components. Table 3-1 shows the percentage of different materials used in each component and each component's percentage of total turbine weight. The table applies to 1.5 MW turbines MW and larger.

Table 3-2 uses the materials consumption model in Table 3-1 to further describe the raw materials required to reach manufacturing levels of about 7,000 turbines per year. This analysis assumes that turbines will become lighter, annual installation rates will level off to roughly 7,000 turbines per year by 2017, and installation will continue at that rate through 2030. Approximately 100,000 turbines will be required to produce 20% of the nation's electricity in 2030.

No single component dominates a wind turbine's total cost, which is generally split evenly among the rotor, electrical system, drivetrain, and tower. The technological progress described in Chapter 2, however, could significantly reduce costs (e.g., through the use of lighter weight components for blades and towers).

The availability of critical resources is crucial for large-scale manufacturing of wind turbines. The most important resources are steel, fiberglass, resins (for composites and adhesives), blade core materials, permanent magnets, and copper. The production status of these materials is reviewed in the following list:

- **Steel:** The steel needed for additional wind turbines is not expected to have a significant impact on total steel production. (In 2005, the United States produced 93.9 million metric tons of steel, or 8% of the worldwide total.) Although steel will be required for any electricity generation technology installed over the next several decades, it can be recycled. As a result, replacing a turbine after 20+ years of service would not significantly affect the national steel demand because recycled steel can be used in other applications where high-quality steel is not required (Laxson, Hand, and Blair 2006).

Table 3-1. Main components and materials used in a wind turbine (%)

1.5 MW	Weight %	Permanent Magnet	Concrete	Steel	Aluminum	Copper	GRP	CRP	Adhesive	Core	TOTAL
Rotor											
Hub	6.0			100							100.0
Blades	7.2			2			78		15	5	100.0
Nacelle											
Gearbox	10.1			96	2	2					100.0
Generator	3.4			65		35					100.0
Frame	6.6			85	9	3	3				100.0
Tower	66.7		2	98							
	100.0	**0.0**	**1.3**	**89.1**	**0.8**	**1.6**	**5.8**	**0.0**	**1.1**	**0.4**	**100.0**
4 MW		**Permanent Magnet**	**Concrete**	**Steel**	**Aluminum**	**Copper**	**GRP**	**CRP**	**Adhesive**	**Core**	
Rotor											
Hub	6.00			100							100.0
Blades	7.6			2			68	10	15	5	100.0
Nacelle											
Gearbox	10.10			96	2	2					100.0
Generator	2.7	3		93		4					100.0
Frame	6.60			85	9	3	3				100.0
Tower	67.00		2	98							
	100.0	**0.08**	**1.34**	**89.63**	**0.80**	**0.51**	**5.37**	**0.76**	**1.14**	**0.38**	**100.0**

Notes: Tower includes foundation. GRP = glass-fiber-reinforced plastic. CRP = carbon fiber reinforced plastic
Source: Sterzinger and Svrcek (2004)

Table 3-2. Yearly raw materials estimate (thousands of metric tons)

Year	kWh/kg	Permanent Magnet	Concrete	Steel	Aluminum	Copper	GRP	CRP	Adhesive	Core
2006	65	0.03	1,614	110	1.2	1.6	7.1	0.2	1.4	0.4
2010	70	0.07	6,798	464	4.6	7.4	29.8	2.2	5.6	1.8
2015	75	0.96	16,150	1,188	15.4	10.2	73.8	9.0	15.0	5.0
2020	80	2.20	37,468	2,644	29.6	20.2	162.2	20.4	33.6	11.2
2025	85	2.10	35,180	2,544	27.8	19.4	156.2	19.2	31.4	10.4
2030	90	2.00	33,800	2,308	26.4	18.4	152.4	18.4	30.2	9.6

Notes: kg = kilograms; GRP = glass-fiber-reinforced plastic. CRP = carbon fiber reinforced plastic
Source: Sterzinger and Svrcek (2004)

- **Fiberglass:** Additional fiberglass furnaces would be needed to build more wind turbines. Primary raw materials for fiberglass (sand) are in ample supply, but availability and costs are expected to fluctuate for resins, adhesives, and cores made from the petroleum-based chemicals that are used to impregnate the fiberglass (Laxson, Hand, and Blair 2006).
- **Core:** End-grain balsa wood is an alternative core material that can replace the low-density polymer foam used in blade construction. Availability of this wood might be an issue based on the growth rate of balsa trees relative to the projected high demand.
- **Carbon fiber:** Current global production of commercial-grade carbon fiber is approximately 50 million pounds (lb) per year. The use of carbon fiber in turbine blades in 2030 alone would nearly double this demand. To achieve such drastic industry scale-up, changes to carbon fiber production technologies, production facilities, packaging, and emissions-control procedures will be required.

3

- **Permanent magnets:** By eliminating copper from the generator rotor and using permanent magnets, which are becoming more economically feasible, it is possible to build smaller and lighter generators. World magnet production in 2005 was about 40,000 metric tons, with about 35,000 metric tons produced in China. Although supply is not expected to be restricted, significant additions to the manufacturing capability would be required to meet the demand for wind turbines and other products (Trout 2002; Laxson, Hand, and Blair 2006).
- **Copper:** Although wind turbines use significant amounts of copper, the associated level of demand still equates to less than 4% of the available copper. This demand level, would not have a significant impact on national demand (U.S. refined copper consumption was 2.27 million metric tons in 2005). Although copper ranks third after steel and aluminum in world metals consumption, global copper production is adequate to satisfy growing demands from the wind industry. However, in recent years copper prices have escalated more quickly than inflation, which could affect turbine costs.

Despite the demand and supply status of these materials, new component developments are expected to significantly change material requirements. Generally, trends are toward using lighter-weight materials, as long as the life-cycle costs are low. In addition to the findings of Ancona and McVeigh (2001; described in the Materials Usage Analysis sidebar), other trends in turbine components are outlined in the subsections that follow.

Material Usage Analysis
(Ancona and McVeigh 2001)

- Turbine material usage is, and will continue to be, dominated by steel.
- Opportunities exist for introducing aluminum or other lightweight composites, provided that cost, strength, and fatigue requirements can be met.
- GRP is expected to continue to be used for blades.
- The use of carbon fiber might help reduce weight and cost.
- Low costs and high reliability remain the primary drivers.
- Variable-speed generators will become more common.
- Permanent-magnet generators on larger turbines will increase the need for magnetic materials.
- Simplification of the nacelle machinery might reduce raw material costs and also increase reliability.

Evolution of Rotors

Most rotor blades in use today are built from glass-fiber-reinforced plastic (GRP). Steel and various composites such as carbon filament-reinforced plastic (CFRP) are also used. As the rotor size increases for larger machines, the trend will be toward high-strength, fatigue-resistant materials. Composites involving steel, GRP, CFRP, and possibly other new materials will likely come into use as turbine designs evolve.

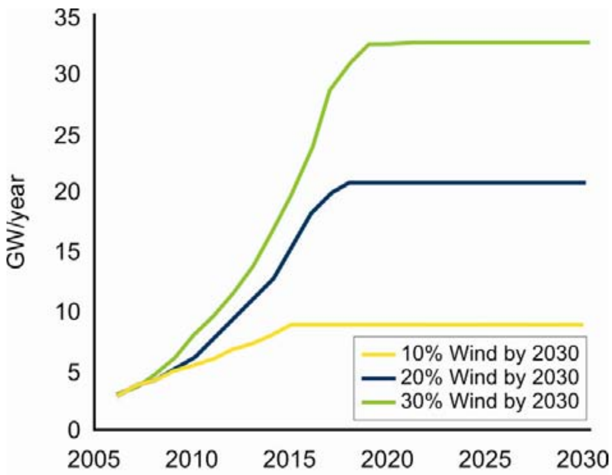
Changes to Machine Heads

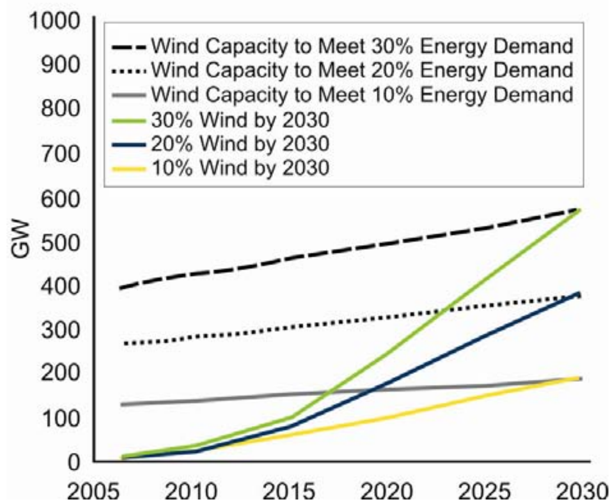
The machine head contains an array of complex machinery including yaw drives, blade-pitch-change mechanisms, drive brakes, shafts, bearings, oil pumps and coolers, controllers, a bedplate, the drivetrain, the gearbox, and an enclosure. Design simplifications and innovations are anticipated in each element of the machine head.

3.2 Manufacturing Capability

In principle, a sustainable level of annual wind turbine installation would be best supported by a substantial domestic manufacturing base. However, if installation rates fluctuate greatly from one year to the next, manufacturing capability may not be able to grow or shrink as necessary. The National Renewable Energy Laboratory (NREL) created a simple model to explore sustainable installation rates that would maintain wind energy production at specific levels spanning several decades (Laxson, Hand, and Blair 2006).

Figure 3-1. a. Annual installed wind energy capacity to meet 20% of energy demand. b. Cumulative installed wind energy capacity to meet 20% of energy demand.



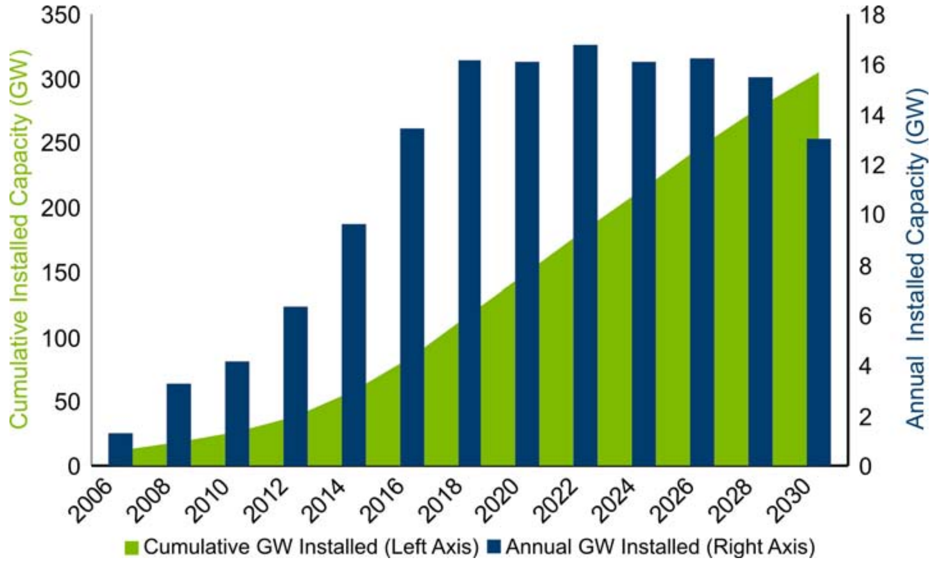


NREL's study explored a number of alternative scenarios for annual wind power capacity expansion to understand their potential impact on wind energy installation and manufacturing rates. The results indicate that achieving the 20% Wind Scenario by 2030 would not overwhelm U.S. industry (Laxson, Hand, and Blair 2006).

NREL's study assessed potential barriers that would prohibit near-term high wind penetration levels, such as manufacturing rates or resource limitations. To reach 20% electric generation from wind by 2030 in the United States, the authors noted, an annual installed capacity increase of about 20% would need to be sustained for a decade (Laxson, Hand, and Blair 2006). Figure 3-1 compares the installation rates required to meet three energy supply goals of 10%, 20%, and 30% of total national electrical energy production from wind by 2030. Figure 3-1(a) shows the annual rates and Figure 3-1(b) shows the cumulative capacity attained in each case. A manufacturing production level of 20 gigawatts (GW) per year by 2017—and maintained at this value thereafter—would reach levels close to 400 GW of wind energy capacity by 2030.

NREL's study assumed that the wind plant capacity factor would not change from year to year or from location to location. This assumption provided an upper bound on the annual installation rate and cumulative capacity required to produce 20% of electricity demand. Alternatively, the 20% Wind Scenario evaluation assumes that plant capacity factors will increase modestly with experience and technology improvements (see Chapter 2). The 20% Scenario also accounts for regional variations in wind resources, as explained in Appendix A's detailed description of the analytic modeling approach employed. Note that when these refinements are included, the 20% curve in Figure 3-1(a) shifts downward, somewhat similar to that shown in Figure 3-2 on the next page.

Figure 3-2. Annual and cumulative installed wind energy capacity represented in the 20% Wind Scenario



This chapter discusses the materials and manufacturing needed to pursue the 20% Wind Scenario from 2007 through 2030 to meet the annual and cumulative installed capacity shown in Figure 3-2. This figure shows the forecasts for annual and cumulative installed wind energy capacity, which also forms the basis for estimates of new wind turbines and the raw materials required to produce them. In this scenario, annual installations climb more than 16 GW per year, and the total installed wind capacity increases to 305 GW by 2030. Between 2007 and 2030, 293 GW are installed. (For more details on the modeling approach used, see Appendix A.)

3.2.1 CURRENT MANUFACTURING FACILITIES

A growing number of states and companies in the United States are ramping up capacity to manufacture wind turbines, or have the ability to do so. Jobs are expected to remain in the United States, but only if investments are made in certain components and in advanced manufacturing technologies. Appendix C describes the jobs and economic impacts associated with wind energy, including manufacturing, construction, and operational sectors of the wind industry.

A useful perspective on growing manufacturing requirements is provided by a non-government organization study released in 2004 called *Wind Turbine Development: Location of Manufacturing Activity* (Sterzinger and Svrcek 2004). This study investigated the current and future U.S. wind manufacturing industry, both to determine the location of companies involved in wind turbine production and to examine limitations to a rapidly expanding wind business. The report covered four census regions (the Midwest, Northeast, South, and West) and divided turbine manufacturing into 20 separate components. These components were grouped into five categories, as shown in Table 3-3. The table also shows the locations of U.S. wind turbine component manufacturers in 2004, broken down by region. Among the 106 companies surveyed, about 90 companies directly manufacture components for utility-scale wind turbines, with utility scale being roughly defined as 1 MW or greater.

Table 3-3. Locations of U.S. wind turbine component manufacturers

Region	Division	Rotor	Nacelle and Controls	Gearbox & Drivetrain	Generator & Power Electronics	Tower	Division Total
Midwest	East North Central	6	5	8	1	2	22
	West North Central	1	0	1	1	8	11
Northeast	Middle Atlantic	3	4	4	5	1	17
	New England	0	6	0	2	0	8
South	East South Central	0	0	0	0	2	2
	South Atlantic	3	2	1	1	2	9
	West South Central	4	5	0	1	6	16
West	Mountain	1	0	0	1	0	2
	Pacific	5	4	2	4	4	19
	Component Total:	**23**	**26**	**16**	**16**	**25**	**106**

(Sterzinger and Svrcek 2004)

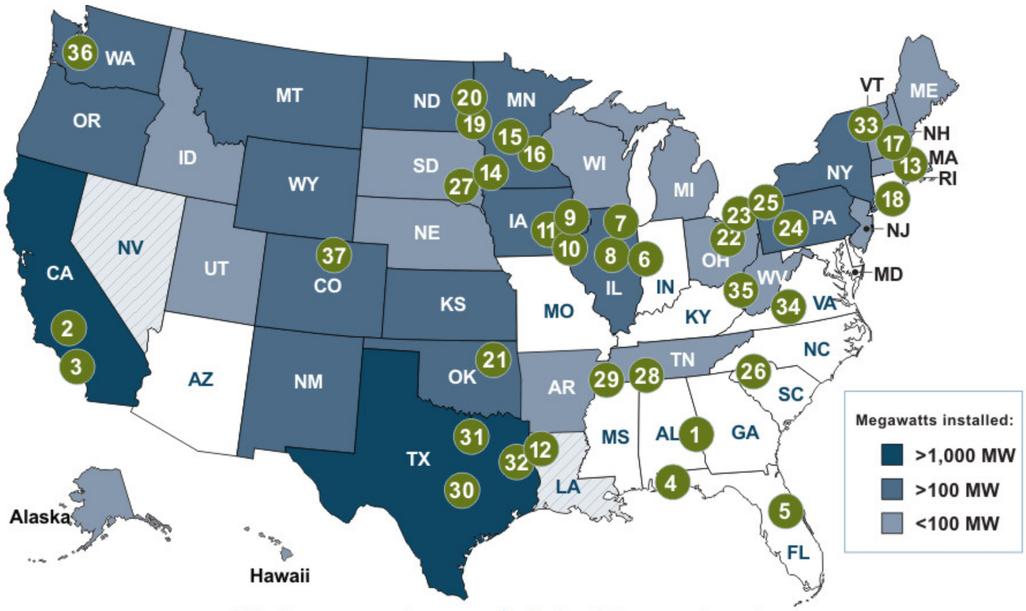
Figure 3-3 on the next page shows the locations of a number of the current manufacturers of wind turbines and components. These firms are widely distributed around the country and some are located in regions with, as yet, little wind power development.

A large national investment in wind would likely spread beyond these active companies. To identify this potential, the North American Industrial Classification System (NAICS; http://www.census.gov/epcd/www/naics.html) was searched to identify companies operating under relevant industry codes. The manufacturing activity related to wind power development is substantial and widely dispersed (Sterzinger and Svrcek 2004). As Table 3-4 shows, more than 16,000 firms are currently producing products under one or more of the NAICS codes that include

Table 3-4. U.S. Manufacturing firms with technical potential to enter wind turbine component market

NAICS Code	Code Description	Total Employees	Annual Payroll ($1000s)	Number of Companies
326199	All Other Plastics Products	501,009	15,219,355	8,174
331511	Iron Foundries	75,053	3,099,509	747
332312	Fabricated Structural Metal	106,161	3,975,751	3,033
332991	Ball and Roller Bearings	33,416	1,353,832	198
333412	Industrial and Commercial Fans and Blowers	11,854	411,979	177
333611	Turbines, and Turbine Generators, and Turbine Generator Sets	17,721	1,080,891	110
333612	Speed Changer, Industrial	13,991	539,514	248
333613	Power Transmission Equip.	21,103	779,730	292
334418	Printed Circuits and Electronics Assemblies	105,810	4,005,786	716
334519	Measuring and Controlling Devices	34,499	1,638,072	830
335312	Motors and Generators	62,164	2,005,414	659
335999	Electronic Equipment and Components, NEC	42,546	1,780,246	979
Total		**1,025,327**	**35,890,079**	**16,163**

Figure 3-3. Examples of manufacturers supplying wind equipment across the United States



Wind power creates manufacturing jobs even in regions like the Southeast that do not have a large wind resource.

1 Vectorply. Phenix City, AL (composites for blades)
2 GE Energy, Tehachapi, CA (wind turbine manufacturing facility)
3 Bragg Crane & Rigging Service, Long Beach, CA (cranes, rigging, transportation)
4 GE Energy, Pensacola, FL (blade technology development)
5 Mitsubishi Power Systems, Lake Mary, FL (gear boxes)
6 White Construction Inc., Clinton, IN (construction services)
7 Winergy Drive Systems Corporation, Elgin, IL (gear units, generators, power converters)
8 Trinity Industries, Clinton, IL (towers)
9 Clipper Windpower, Cedar Rapids, IA (turbine manufacturing, assembly)
10 Siemens, Fort Madison, IA (blades)
11 Acciona Energia, West Branch, IA (planned) (turbine manufacturing)
12 Beaird Industries, Shreveport, LA (towers, tower flanges and bolts)
13 Second Wind Inc., Somerville, MA (anemometers, electronic controllers, sensors/data loggers)
14 Suzlon Wind Energy, Pipestone, MN (blade manufacture, turbine assembly)
15 D.H. Blattner & Sons, Avon, MN (construction)
16 M.A. Mortenson Co., Minneapolis, MN (construction)
17 Hendrix Wire & Cable Inc., Milford, NH (cables to substations)
18 Hailo LLC, Holbrook, NY (ladder and lift systems)
19 DMI Industries, West Fargo, ND (towers)
20 LM Glasfiber, Grand Forks, ND (blades)
21 Trinity Structural Towers, Tulsa, OK (towers)
22 Owens Corning Composites, Granville, OH (composites for blades)
23 Hamby Young, Aurora, OH (substations and high voltage applications)
24 Gamesa, Ebensburg, PA (blade, nacelle, tower manufacturing)
25 GE Energy, Erie, PA (wind turbine components)
26 GE Energy, Greenville, SC (turbine assembly plant)
27 Knight & Carver, Howard, SD (blade manufacturing)
28 Aerisyn Inc, Chattanooga, TN (towers)
29 Thomas & Betts Corp., Memphis, TN (towers, tower flange and bolts)
30 DeWind, Inc./TECO Westinghouse, Round Rock, TX (wind turbine manufacturing)
31 Trinity Structural Towers, Fort Worth, TX (towers)
32 CAB Incorporated, Nacogdoches, TX (blade extender, hub, nacelle frame, tower flange and bolts)
33 NRG Systems, Hinesburg, VT (anemometers, sensors/data loggers)
34 GE Energy, Salem, VA (wind turbine components)
35 Tower Logistics, Huntington, WV (lifts for turbines)
36 PowerClimber, Seattle, WA (traction hoists, rigging equipment)
37 Vestas, Windsor, CO (planned) (blade and turbine manufacturing)

manufacture of wind components. These firms are spread across all 50 states. They are concentrated, however, in the most populous states and the states that have suffered the most from loss of manufacturing jobs. The 20 states that would likely receive the most investment and the most new manufacturing jobs from wind power expansion account for 75% of the total U.S. population, and 76% of the manufacturing jobs lost in the last 3.5 years.

A 2006 NGO report entitled "*Renewable Energy Potential: A Case Study of Pennsylvania* (Sterzinger and Stevens 2006) identified the bottlenecks in the component supply chain. Bottlenecks were identified for various components, but obtaining gearbox components was particularly problematic. Currently, only a few manufacturers in the world deliver gearboxes for large wind turbines. Additional investments will be required to support the development of a gearbox industry specifically for large wind applications. Investments will also be needed to expand the manufacture of large bearings and large castings.

The wind equipment manufacturing sector also faces trade-offs between using domestic or foreign manufacturing facilities. An advantage to domestic operations is a reduction reducing the significant transportation costs of moving large components such as blades and towers. Manufacturing many significant wind turbine components is also a labor-intensive process. With U.S. labor wage rates at higher levels than those paid in many other countries, manufacturers have naturally been drawn to setting up their factories outside the United States (e.g., in Mexico and China). One wind blade manufacturer with significant international manufacturing experience estimates that, to make a U.S. factory competitive, the labor hours per blade would need to be reduced by a factor of 30%–35%. To ensure that the bulk of these manufacturing jobs stay in the United States, automation and productivity gains through the development of advanced manufacturing technology are needed. These gains will allow the higher U.S. wage rates to be competitive.

To attract these jobs, a number of U.S. states have set aside funds for RD&D, with plans to collaborate with industry and the federal government on a cost-shared basis. Collaboration among state, industry, and federal programs on advanced manufacturing technology can create competitive U.S. factories and provide better job security for U.S. employees.

3.2.2 Ramping Up Energy Industries

In the United States, several industries have experienced large rates of growth over a short period of time. The power plants most commonly used to produce electricity around the world—such as thermal power stations fired with coal, gas or oil, or nuclear reactors—are large in scale. Nuclear power stations, developed mainly since the middle of the twentieth century, have now reached a penetration of 17.1% in the world's power supply. Worldwide, nuclear power plant installations saw a 17% annual growth rate between 1960 and 1997 (BTM 1999). Despite a halt in new nuclear plant licensing in the early 1980s, U.S. nuclear plants generate about 20% of the nation's electrical energy, and have done so for the last decade or more. The history of nuclear power shows that it is possible to achieve substantial levels of penetration over two to three decades with a new technology.

Even though the time horizon of the 20% Wind Scenario is consistent with the historical development of nuclear power, it is nonetheless difficult to directly compare penetration patterns for nuclear power that is typically about 1,000 MW and wind power technology. A wind turbine is a smaller-scale technology that has a current typical commercial unit size of 2 MW–3 MW. Despite the smaller scales of wind power, its modularity makes it ideal for all sizes of installations—from a single unit (2 MW–3 MW) to a large utility-scale wind farm (1,000 MW). On the supply side, serial production of large numbers of similar units can reduce manufacturing costs. These factors suggest that manufacturing ramp-up for wind turbines should be less daunting than ramp-up for nuclear power plant equipment.

Experiences with natural-gas-fired power plants over the past decade also provide important perspectives on the ability to rapidly expand manufacturing capability for wind power. From the early 1990s through the first half of the current decade, the U.S. electric sector experienced a rush toward new gas combined-cycle and combustion-turbine generation. This growth was driven by the expectation—now discounted—of continuing low natural gas prices. From 1999 through 2005, tens of gigawatts of natural gas power plants were manufactured and installed in the United States each year, with installations peaking in 2002 at more than 60 GW (Black & Veatch 2007). The experience with natural gas demonstrates that huge amounts of power generation equipment can be manufactured in the United States if sufficient market demand exists.

As Table 3-5 shows, Toyota North America exemplifies the manufacturing scale-up of a modular technology and capability that is possible in the United States. Toyota has continued to establish U.S. manufacturing capability since the mid-1980s, and automobiles, like wind turbines, require large quantities of steel, plastics, and electronic components. There is no indication that Toyota's domestic expansion caused any strain on the nation's manufacturing or materials-supply sectors. Today, the majority of vehicles Toyota sells in the U.S. are produced in this country.

Table 3-5. Toyota North America vehicle production and sales

Direct U.S. Employment (2005)	32,003 employees
2005 Payroll	$2,244,946,444
Cumulative U.S. Production	12,374,062 vehicles
Cumulative Sales	$272,390,226,806
U.S. Vehicle Sales (2005)	2,269,296 vehicles
U.S. Vehicle Production (2005)	1,393,100 vehicles
Average Engine Power 2004-2005	227 horsepower or 0.17 MW
2005 U.S. Production in Power Output Terms	275 million horsepower 236 million kW or 236 GW
2005 U.S. Sales in Power Output Terms	448 million horsepower 384 million kW or 384 GW

Source: Adapted from Toyota website data http://www.toyota.com/about/operations/manufacturing/

Table 3-5 shows that Toyota's annual U.S. production, when expressed in terms of engine power output, increased to 236 GW by 2005. This annual production begins to approach in power capability the total amount of wind generation installed between 2007 and 2030 through realization of the 20% Wind Scenario.

3.3 LABOR REQUIREMENTS

Beyond the raw material and manufacturing facilities required to create wind turbines and components, a skilled labor force would be required. This staff would need a range of skills and experience to fill many new employment opportunities. The likely outcome from developing new capabilities and capacity would be expansion of manufacturing in areas currently capable of competing or development in locations where logistic advantages exist.

3.3.1 MAINTAINING AND EXPANDING RELEVANT TECHNICAL STRENGTH

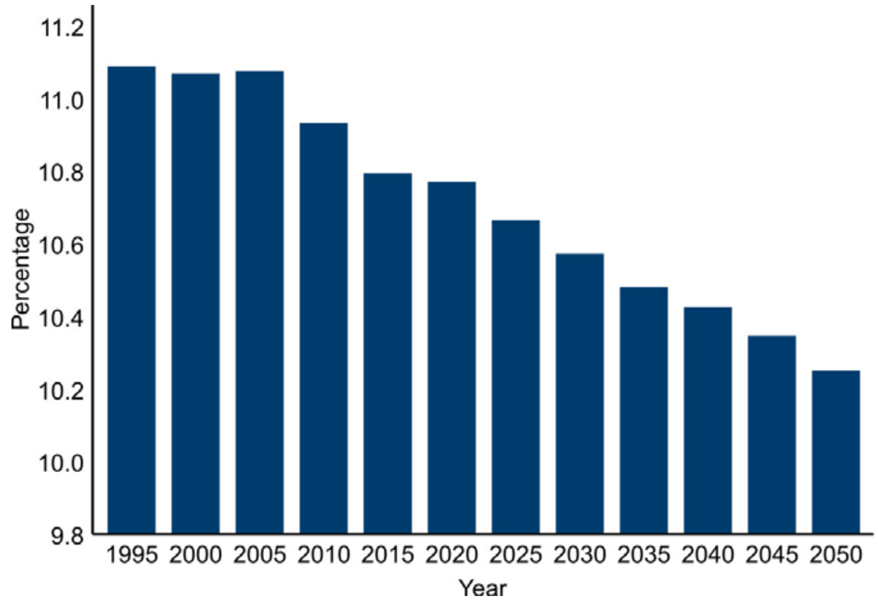
Major expansion of wind power in the United States would require substantial numbers of skilled personnel available to design, build, operate, maintain, and advance wind power equipment and technology. Toward this end, a number of educational programs are already offered around the nation, including those shown in Table 3-6.

Table 3-6. Wind technology-related educational programs around the United States today

School	Location	Degree or Program
Wind Energy Applications Training Symposium	Boulder, Colorado	Workshops for industry
Colorado State University	Fort Collins, Colorado	65 MW turbine on campus for research (engineering, environmental, etc.)
Advanced Technology Environmental Education Center: Sustainable Energy Education and Training	Bettencourt, Iowa	Workshops for upper level high school and community college technology instructors
Iowa Lakes Community College	Estherville, Iowa	One-year diploma for wind technician; two-year associate in applied science degree for wind technician
University of Massachusetts at Amherst: College of Engineering, and Renewable Energy Research Laboratory (becoming University of Massachusetts Wind Energy Center in late 2008)	Amherst, Massachusetts	MS and Ph.D. level engineering programs specializing in wind energy
Minnesota West Community and Technical College	Canby, Maine	Associate of applied science degree program in wind energy technology; diploma for wind energy mechanic; online certificate program for "windsmith"
Southwestern Indian Polytechnic Institute	Albuquerque, New Mexico	Under development: Integration of renewable energy technology experiential learning into the electronics technology, environmental science, agricultural science, and natural resources certificate and degree programs
Mesalands Community College: North American Wind Research and Training Center	Tucumcari, New Mexico	Under development: Curriculum for operations and maintenance technician; two-year associate degree in wind farm management
Wayne Technical and Career Center	Williamson, New York	New Vision Renewable Energy Program for high school seniors
Columbia Gorge Community College	Hood River, Oregon	One-year certificate and two-year degree for renewable energy technician
Lane Community College	Eugene, Oregon	Two-year associate of applied science degree for energy management technician; two-year associate of applied science option for renewable energy technician
Texas Tech and other American universities: Wind Science & Engineering Research Center	Lubbock, Texas	Integrative graduate education and research traineeship
Lakeshore Technical College	Cleveland, Wisconsin	Associate degree in applied science; electromechanical technology with a wind system Technician track
Fond du Lac Tribal and Community College	Fond du Lac, Wisconsin	Clean Energy Technician Certificate Program

Although this is an excellent beginning, many more programs of a similar nature will be needed nationwide to satisfy the needs stemming from the 20% Wind Scenario. One concern is that the number of students in power engineering programs has been dropping in recent years. Currently, U.S. graduate power engineering programs produce about 500 engineers per year; in the 1980s, this number approached 2,000. In addition, the number of wind engineering programs in U.S. graduate schools is significantly lower than in Europe. This concern is echoed in Figure 3-4 below, which shows that the number of college graduates receiving

Figure 3-4. Projected percentage of 22-year-olds with a bachelor's degree in science and engineering through 2050



degrees in science and engineering has been declining, and that this trend is projected to continue for the foreseeable future (NSTC 2000).

Even the level of U.S. graduate programs is well below similar graduate programs in Europe (Denmark, Germany, etc). At this rate, the United States will be unable to provide the necessary trained talent and manufacturing expertise. Unless this trend is reversed, even with major new wind installations in the United States, most of the technology will be imported, and a significant portion of the economic gains will be foreign rather than domestic.

3.4 Challenges to 20% Wind Energy by 2030

3.4.1 Challenges

Materials

Several key materials are crucial to the production of a wind turbine. The availability of some key raw materials—including fiberglass (about 9 metric tons required per megawatt of wind turbine capacity), resins, and permanent magnets—might potentially constrain the ability to develop an infrastructure producing high levels of wind power. To give perspective, the glass fiber requirements would be about half the level used domestically for roofing shingles (which is currently the largest consumer of fiberglass) and about double the amount now used in boat building.

Manufacturing

The 20% Wind Scenario would demand installations at a sustained growth rate of 20% annually for nearly a decade and then require maintaining that level of annual installations through 2030. For turbine companies, it is no longer simply a matter of where to establish new manufacturing capacity. Investment decisions must now address strategies for building out and securing supply lines on a global basis; a proactive stance is essential to operate successfully in an environment of rapidly growing and shifting demand for wind turbines (Hays, Robledo, and Ambrose 2006). Fortunately, the 20% Wind Scenario could be feasible even with the potential challenges related to the availability of raw material or increased manufacturing demands. For rapid growth of manufacturing capacity to be achieved, stable and consistent policies that encourage investment in these new sectors of activity are needed.

Labor

One potential gap in achieving high rates of wind energy development is the availability of a qualified work force. In a report published by the National Science and Technology Council (NSTC), as noted above, the percentage of 22-year-olds earning degrees in science and engineering will continue to drop in the next 40 years (NSTC 2000). More support from industry, trade organizations, and various levels of government could foster university programs in wind and renewable energy technology, preparing the work force to support the industry's efforts.

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Chapter 4. Transmission and Integration into the U.S. Electric System

The ever-increasing sophistication of the operation of the U.S. electric power system—if it continues on its current path—would allow the 20% Wind Scenario to be realized by 2030. The 20% Wind Scenario would require the continuing evolution of transmission planning and system operations, in addition to expanded electricity markets.

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There are two separate and distinct power system challenges to obtaining 20% of U.S. electric energy from wind. One challenge lies in the need to reliably balance electrical generation and load over time when a large portion of energy is coming from a variable power source such as wind, which, unlike many traditional power sources, cannot be accessed on demand or is "nondispatchable." The other challenge is to plan, build, and pay for the new transmission facilities that will be required to access remote wind resources. Substantial work already done in this field has outlined scenarios in which barriers to achieving the 20% Wind Scenario could be removed while maintaining reliable service and reasonable electricity rates.

This chapter begins with an examination of several detailed studies that have looked at the technical and economic impacts of integrating high levels of wind energy into electric systems. Next, this chapter examines how wind can be reliably accommodated into power system operations and planning. Transmission system operators must ensure that enough generation capacity is operating on the grid at all times, and that supply meets demand, even through the daily and seasonal load cycles within the system. To accommodate a nondispatchable variable source such as wind, operators must ensure that sufficient reserves from other power sources are available to keep the system in balance. However, overall it is the net system load that must be balanced, not an individual load or generation source in isolation. When seen in this more systemic way, wind energy can play a vital role in diversifying the power system's energy portfolio.

As the research discussed in this chapter demonstrates, wind's variability need not be a technical barrier to incorporating it into the broader portfolio of available options. Although some market structures, generation portfolios, and transmission rules accommodate much more wind energy than others, reforms already under consideration in this sector can better accommodate wind energy. Experience and studies suggest that with these reforms, wind generation could reliably supply 20% of U.S. electricity demand.

Finally, this chapter assesses the feasibility and cost of building new transmission lines and facilities to tap the remote wind resources that would be needed for the 20% Wind Scenario. Many challenges are inherent in building transmission systems to accommodate wind energy. If electric loads keep growing as expected, however, extensive new transmission will be required to connect new generation to loads. Over the coming decades, this will be true regardless of the power sources that dominate, whether they are fossil fuels, wind, hydropower, or others. The U.S. power industry has renewed its commitment to a robust transmission system, and support continues to grow for cleaner generation options. In this environment, designers and engineers must find ways to build transmission at a reasonable cost and take a closer look at the alternatives to conventional power generation in a carbon-constrained future.

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Wind Penetration Levels

At least three different measures are used to describe wind penetration levels: energy penetration, capacity penetration, and instantaneous penetration. They are defined and related as follows:

Energy penetration is the ratio of the amount of energy delivered from the wind generation to the total energy delivered. For example, if 200 megawatt-hours (MWh) of wind energy are supplied and 1,000 MWh are consumed during the same period, wind's energy penetration is 20%.

Capacity penetration is the ratio of the nameplate rating of the wind plant capacity to the peak load. For example, if a 300 MW wind plant is operating in a zone with a 1,000 MW peak load, the capacity penetration is 30%. The capacity penetration is related to the energy penetration by the ratio of the system load factor to the wind plant capacity factor. Say that the system load factor is 60% and the wind plant capacity factor is 40%. In this case, and with an energy penetration of 20%, the capacity penetration would be 20% × 0.6/0.4, or 30%.

Instantaneous penetration is the ratio of the wind plant output to load at a specific point in time, or over a short period of time.

4.1 Lessons Learned

4.1.1 Wind Penetration Experiences and Studies

The needs of system operators—reflected in grid codes—ensure that wind power will continue to be integrated in ways that guarantee the continued reliable operation of the power system. Grid codes are regulations that govern the performance characteristics of different aspects of the power system, including the behavior of wind plants during steady-state and dynamic conditions. Grid codes around the world are also changing to incorporate wind plants; the Federal Energy Regulatory Commission (FERC) Order 661-A in the United States is an example.

Several U.S. utilities are approaching 10% wind capacity as a percentage of their peak load, including the Public Service Company of New Mexico (PNM) and Xcel

Energy (which serves parts of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas, and Wisconsin). Xcel Energy could actually exceed 13% by the end of 2007. MidAmerican Energy in Iowa has already exceeded 10%, and Puget Sound Energy (PSE) in Washington expects to reach 10% capacity penetration shortly after 2010.

4.1.2 Power System Studies Conclude that 20% Wind Energy Penetration Can Be Reliably Accommodated

Rapid growth in wind power has led a number of utilities in the United States to undertake studies of the technical and economic impacts of incorporating wind plants, or high levels of wind energy, into their electric systems. These studies are yielding a wealth of information on the expected impacts of wind plants on power system operations.

General Electric International (GE), for example, has conducted a comprehensive study for New York state that examines the impact of 10% capacity penetration of wind by 2008 (Piwko et al. 2005). The state of California has set the ambitious goal of achieving 20% of its electrical energy from renewable sources by 2010 and 30% by 2020 (CEC 2007). The state of Minnesota has studied wind energy penetration of up to 25%, to be implemented statewide by 2020 (EnerNex Corporation 2006). The Midwest ISO (independent system operator) has examined the impact of achieving a wind energy penetration of 10% in the region by 2020, with 20% in Minnesota (Midwest ISO 2006).

U.S. experience with studies on wind were reviewed in a special issue of the Institute of Electrical and Electronics Engineers (IEEE) *Power & Energy Magazine* (IEEE 2005). The Utility Wind Integration Group (UWIG) also summarized these studies in cooperation with the three large utility trade associations—the Edison Electric Institute (EEI), the American Public Power Association (APPA), and the National Rural Electric Cooperative Association (NRECA). The UWIG (2006) summary came to the following conclusions:

- "Wind resources have impacts that can be managed through proper plant interconnection, integration, transmission planning, and system and market operations."
- "On the cost side, at wind penetrations of up to 20% of system peak demand, system operating cost increases arising from wind variability and uncertainty amounted to about 10% or less of the wholesale value of the wind energy. These conclusions will need to be reexamined as results of higher-wind-penetration studies—in the range of 25%–30% of peak balancing-area load—become available. However, achieving such penetrations is likely to require one or two decades."
- "During that time, other significant changes are likely to occur in both the makeup and the operating strategies of the nation's power system. Depending on the evolution of public policies, technological capabilities, and utility strategic plans, these changes can be either more or less accommodating to the natural characteristics of wind power plants."

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- "A variety of means—such as commercially available wind forecasting and others discussed below—can be employed to reduce these costs."
- "There is evidence that with new equipment designs and proper plant engineering, system stability in response to a major plant or line outage can actually be improved by the addition of wind generation."
- "Since wind is primarily an energy—not a capacity—source, no additional generation needs to be added to provide back-up capability provided that wind capacity is properly discounted in the determination of generation capacity adequacy. However, wind generation penetration may affect the mix and dispatch of other generation on the system over time, since non-wind generation is needed to maintain system reliability when winds are low."
- "Wind generation will also provide some additional load carrying capability to meet forecasted increases in system demand. This contribution is likely to be up to 40% of a typical project's nameplate rating, depending on local wind characteristics and coincidence with the system load profile. Wind generation may require system operators to carry additional operating reserves. Given the existing uncertainties in load forecasts, the studies indicate that the requirement for additional reserves will likely be modest for broadly distributed wind plants. The actual impact of adding wind generation in different balancing areas can vary depending on local factors. For instance, dealing with large wind output variations and steep ramps over a short period of time could be challenging for smaller balancing areas, depending on the specific situation."

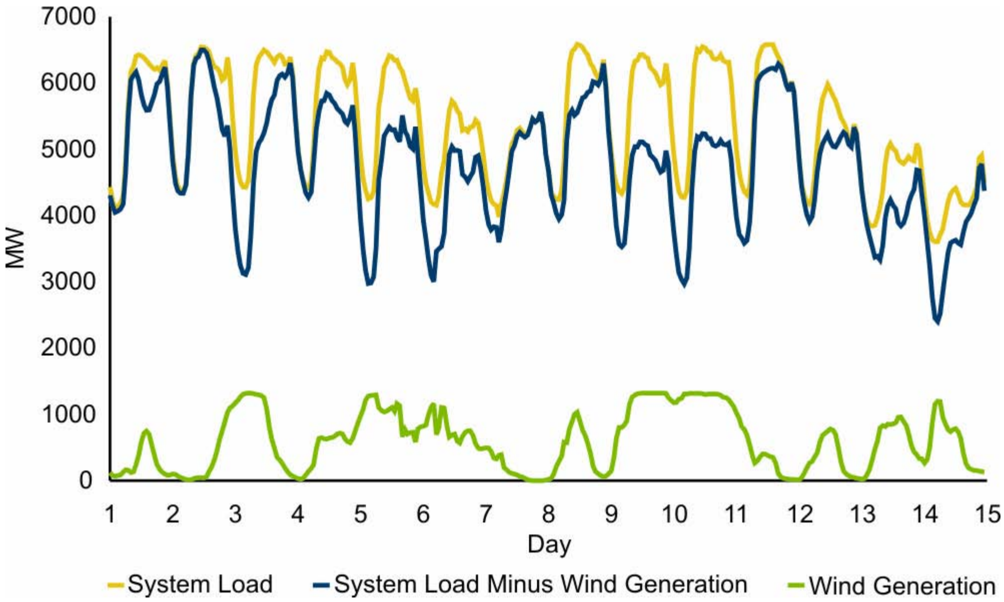
Load, Wind Generation, and Reserves

The first phase in determining how to integrate wind energy into the power grid is to conduct a wind integration study, which begins with an analysis of the impact of the wind plant profiles relative to the utility load curve. By way of illustration, Figure 4-1 shows a two-week period of system loads in the spring of 2010 for the Xcel system in Minnesota. This system has 1,500 MW of wind capacity on a 10,000 MW peak-load system (Zavadil et. al. 2004). Because both load and wind generation vary, it is the resulting variability—load net of wind generation—that system operators must manage, and to which the non-wind generation must respond.

Although wind plants exhibit significant variability and uncertainty in their output, electric system operators already deal with these factors on similar time scales with current power system loads. It is critical to understand that output variability and uncertainty are not dealt with in isolation, but rather as one component of a large, complex system. The system must be operated with balance and reliability, taking into account the aggregate behavior of all of its loads and generation operating together.

To maintain system balance and security, the electric system operator analyzes the regulation and load-following requirements of wind relative to other resources. Wind energy contributes some net increase in variability above that already imposed by cumulative customer loads. This increase, however, is less than the isolated variability of the wind alone on all time scales of interest. Although specific details

Figure 4-1. Hourly load shapes with and without wind generation

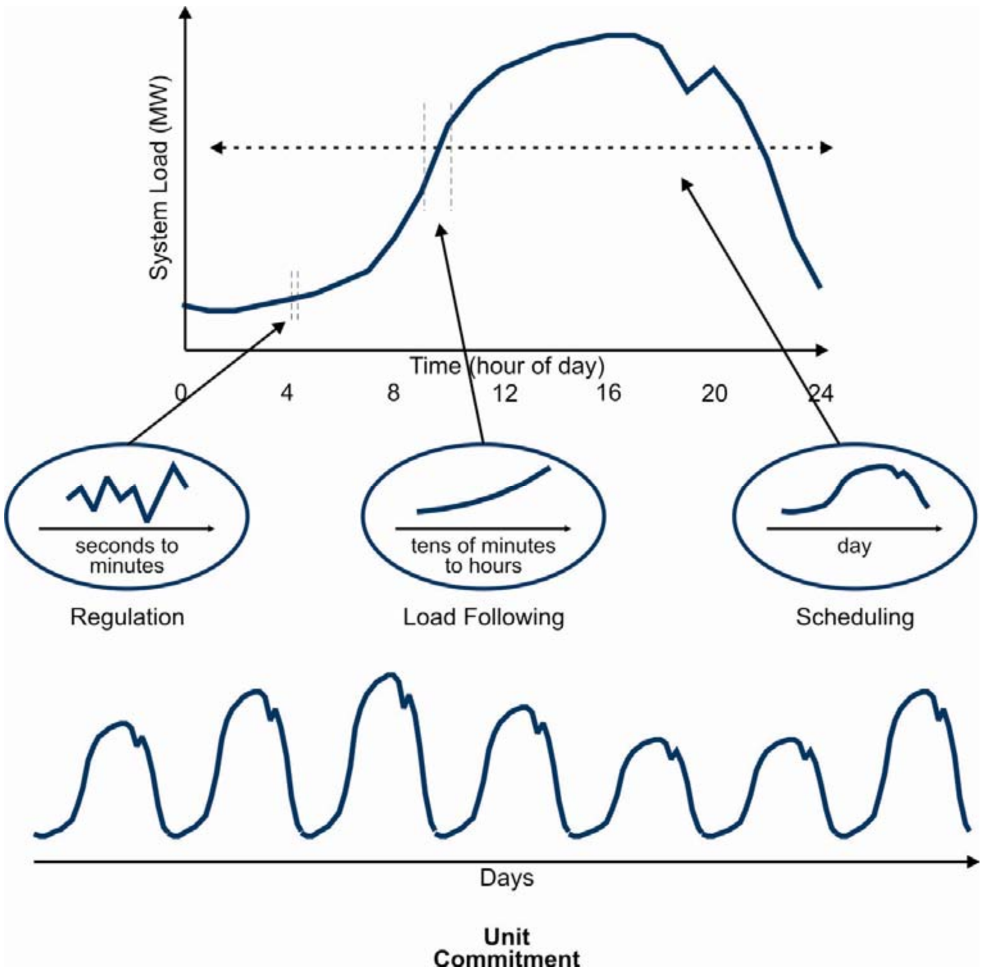


vary, distribution of changes in the load net flattens and broadens when large-scale wind is added to the system. The resulting reserve requirements can be predicted with statistical analysis. It is not necessary, or economically feasible, to counter each movement of wind with a corresponding movement in a traditional energy source. As a result, the load net of wind requires fewer reserves than would be required to balance the output of individual wind plants, or all the wind plants aggregated together, in isolation from the load. In the very short time frame, the additional regulation burden has been found to be quite small, typically adding less than $0.50/MWh to the cost of the wind energy (Zavadil, et. al. 2004).

Operational impacts of nondispatchable variable resources can occur in each of the time scales managed by power system operators. Figure 4-2 below illustrates these time scales, which range from seconds to days. "Regulation" is a service that rapid-response maneuverable generators deliver on short time scales, allowing operators to maintain system balance. This typically occurs over a few minutes, and is provided by generators using automatic generation control (AGC). "Load following" includes both capacity and energy services, and generally varies from 10 minutes up to several hours. This time scale incorporates the morning load pick-up and evening load drop-off. The "scheduling" and "unit-commitment" processes ensure that sufficient generation will be available when needed over several hours or days ahead of the real time schedule.

A statistical analysis of the load net of wind indicates the amount of reserves needed to cope with the combination of wind and load variability. The reserve determination starts with the assumption that wind generation and load levels are independent variables. The resultant variability is the square root of the sum of the squares of the individual variables (rather than the arithmetic sum). This means that the system operator, who must balance the total system, needs a much smaller amount of reserves to balance the load net of wind. Higher reserves would be needed if that operator were to try to balance the output of individual wind plants, or all the wind plants aggregated together in isolation from the load.

Figure 4-2. Time scales for grid operations



Source: Milligan et al. (2006)

Some suggest that hydropower capacity, or energy storage in the form of pumped hydro or compressed air, should be dedicated to supply backup or firming and shaping services to wind plants. Given an ideally integrated grid, this capacity would not be necessary because the pooling of resources across an electric system eliminates the need to provide costly backup capacity for individual resources. Again, it is the net system load that needs to be balanced, not an individual load or generation source in isolation. Attempting to balance an individual load or generation source is a suboptimal solution to the power system operations problem

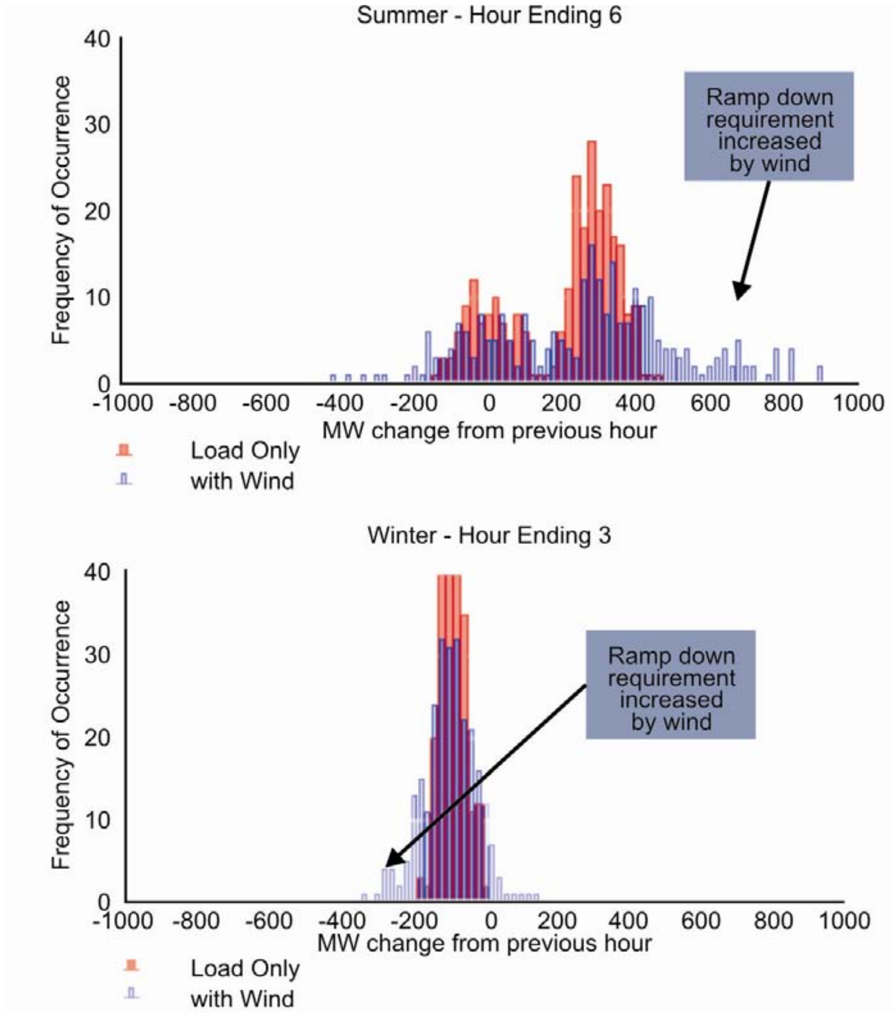
Reserve Requirements Calculation

A hypothetical example is offered to calculate reserve requirements. Say that system peak load for tomorrow is projected at 1,000 MW with a 2% forecast error, which makes the forecast error (i.e., expected variability of peak load) equal to 20 MW. Wind generation for a 200 MW wind plant in that balancing area is predicted at a peak hour output of 100 MW with an error band of 20%. The expected variability of peak wind generation, then, is 20 MW. Assuming that these are independent variables, the total error is calculated as the square root of the sum of the squares of the individual variables (which is the square root of (2 × 20) squared, or 1.41 × 20, which equals 28 MW). Adding the two variables to estimate reserve requirements would result in an incorrect value of 40 MW.

because it introduces unnecessary extra capacity and an associated increase in cost. Hydro capacity and energy storage are valuable resources that should be used to balance the system, not just the wind capacity.

Figure 4-3 illustrates the incremental load-following impact of wind on an electrical system, as determined in the work of Zavadil and colleagues (2004). The histograms show more high-ramp requirements with wind than without wind, and a general reduction in small-ramp requirements compared to the no wind case. For these illustrative summer and winter hours, following load alone entails relatively fewer large-megawatt changes in generation (ramps). Following load net of wind generation, however, creates a wider variability in the magnitude of load change between two adjacent hours. A system with wind generation needs more active load-following generation capability than one without wind, or more load-management capability to offset the combined variability of load net of wind.

Figure 4-3. Impact of wind on load-following requirements



Wind Integration Cost

One impact of the variability that wind imposes on the system is an increase in the uncertainty introduced into the day-ahead unit-commitment process. Specifically, despite improvements in wind generation forecasting, greater uncertainty remains about what the next day's load net of wind and resulting generation requirements

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will be. The impact of these effects has been shown to increase system operating cost by up to $5.00/MWh of wind generation at wind capacity penetrations up to 20%. These figures are shown in the Unit-Commitment Cost column of Table 4-1. These day-ahead cost impacts are significantly higher than the others, reflecting the high cost of starting up generating units on a daily basis—even when they might not be needed.

The impact of wind's variability depends on the nature of the dispatchable generation sources, their fuel cost, the market and regulatory environment, and the characteristics of the wind generation resources. The most recent study conducted for Minnesota, for example, examined up to 25% energy penetration in the Midwest ISO market context (EnerNex 2006). The study found that the cost of wind integration is similar to that found in a study done two years earlier for a 15% wind capacity penetration in a vertically integrated market (Zavadil et al. 2004). A comparison of these results illustrates the beneficial effect of regional energy markets, namely that large operational structures reduce variability, contain more load-following resources, and offer more useful financial mechanisms for managing the costs of wind integration. Handling large output variations and steep ramps over short time periods (e.g., within the hour), though, can be challenging for smaller balancing areas.

Table 4-1 shows the integration cost results from recent U.S. studies. The wind integration issue is primarily a matter of cost, but the costs in the 20% Wind Scenario are expected to be less than 10% of the wholesale cost of energy (COE).

Table 4-1. Wind integration costs in the U.S.

Date	Study	Wind Capacity Penetration (%)	Regulation Cost ($/MWh)	Load Following Cost ($/MWh)	Unit Commit-ment Cost ($/MWh)	Gas Supply Cost ($/MWh)	Total Operating Cost Impact ($/MWh)
May 03	Xcel-UWIG	3.5	0	0.41	1.44	na	1.85
Sep 04	Xcel-MNDOC	15	0.23	na	4.37	na	4.60
Nov 06	MN/MISO	35 (25% energy)	0.15	na	4.26	na	4.41
July 04	CA RPS Multi-year Analysis	4	0.45	na	na	na	na
June 03	We Energies	4	1.12	0.09	0.69	na	1.90
June 03	We Energies	29	1.02	0.15	1.75	na	2.92
2005	PacifiCorp	20	0	1.6	3.0	na	4.6
April 06	Xcel-PSCo	10	0.20	na	2.26	1.26	3.72
April 06	Xcel-PSCo	15	0.20	na	3.32	1.45	4.97

Source: Adapted from IEEE (2005)

Wind Penetration Impacts

U.S. studies for capacity penetrations in the range between 20% and 35% have found that the additional reserves required to meet the intrahour variability are within the capabilities of the existing stack of units expected to be committed. In the high-penetration Minnesota study (EnerNex 2006), changes in total reserve requirements amounted to 7% of the wind generation needed to reach 25% wind energy penetration (5,700 MW). These reserves included 20 MW of additional regulating reserve, 24 MW of additional load-following reserve, and 386 MW maximum of additional operating reserve to cover next-hour errors in the wind forecast. Existing capacity is expected to cover these reserve needs, although over time, load growth could reduce this spare capacity if new dispatchable power plants are not constructed. Because wind and load are generally uncorrelated over short time scales, the regulation impact of wind is modest. The system operator will schedule sufficient spinning and nonspinning reserves so that unforeseen events do not endanger system balance, and so that control performance standards prescribed by the North American Electric Reliability Corporation (NERC) are met.

4.1.3 Wind Turbine Technology Advancements Improve System Integration

As described in more detail in the Wind Turbine Technology chapter, wind turbine technology has advanced dramatically in the last 20 years. From a performance point of view, modern wind power plants have much in common with conventional utility power plants, with the exception of variability in plant output. In the early days of wind power applications, wind plants were often thought of as a curiosity or a nuisance. Operators were often asked to disconnect from the system during a disturbance and reconnect once the system was restored to stable operation. With the increasing penetration of wind power, most system operators recognize that wind plants can and should contribute to stable system operation during a disturbance, as do conventional power plants.

As grid codes are increasingly incorporating wind energy, new plants are now capable of riding through a serious fault at the point of interconnection and are able to contribute to the supply of reactive power and voltage control, just like a conventional power plant. The supply of reactive power is a critical aspect of the design and operation of an interconnected power system. Modern wind plants can perform this function and supply voltage support for secure grid operations.

In addition, modern wind plants can be integrated into a utility's supervisory control and data acquisition (SCADA) system. They can provide frequency response similar to that of other conventional machines and participate in plant output control functions and ancillary service markets. Figure 4-4 illustrates the ability of a wind power plant to increase its output (grey line) in response to a drop in system frequency (red line). Figure 4-5 illustrates various control modes possible via

Figure 4-4. GE turbine frequency response

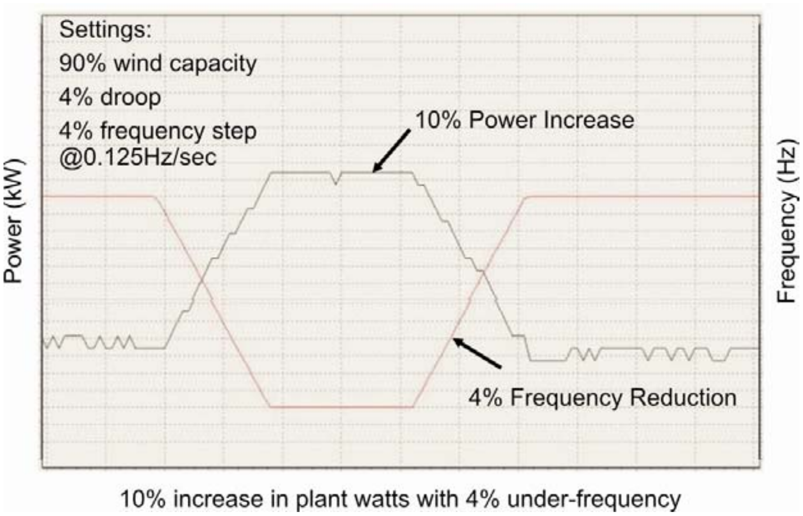

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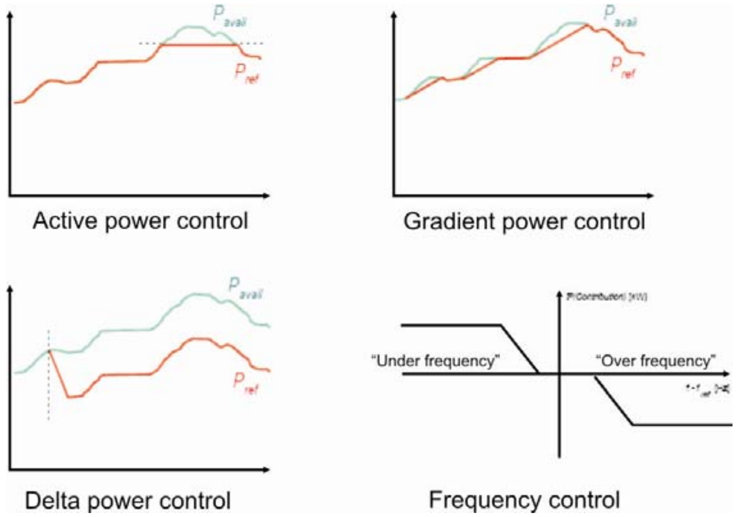
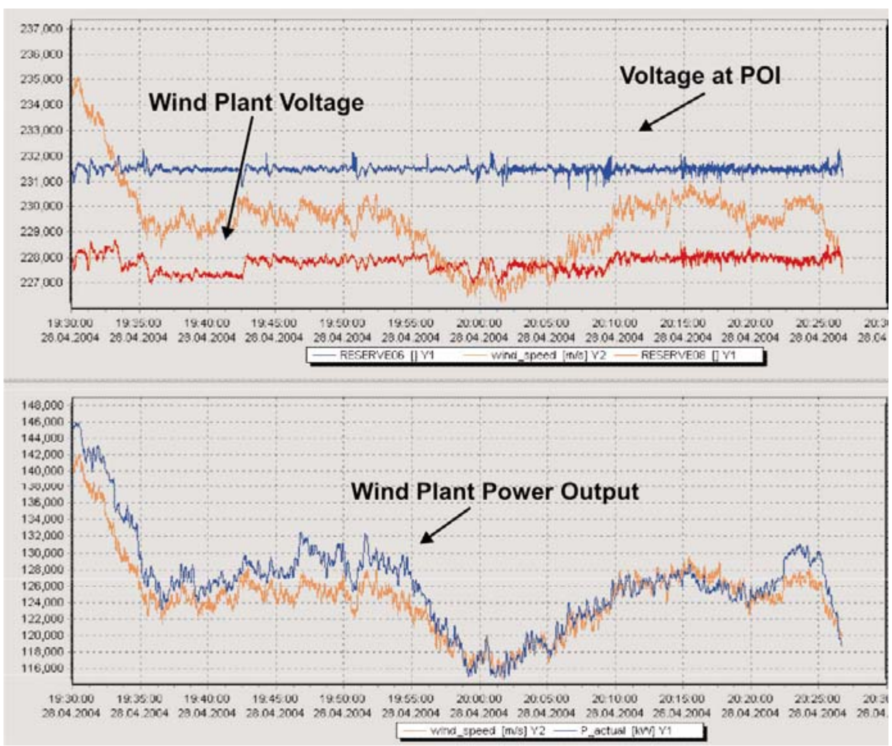
Figure 4-5. Vestas wind turbine control capability



SCADA participation, including the ability to limit plant output power at any given time, control ramp rate in moving up or down, and carry spinning reserves as ordered (Saylors 2006). These plants also have the ability to tap frequency-responsive reserves. These control features come at a cost, however, which is that of "spilling" wind, a free energy resource. In any given geographic area, the cost of operating wind units in this manner so as to provide ancillary services would have to be compared with the cost of furnishing such services by other means.

Wind plant control systems offer another mechanism for dealing with the variability of the wind resource. Controllers can hold system voltage constant at a remote bus, even under widely varying wind speed conditions. Figure 4-6 shows an example of

Figure 4-6. GE wind plant controls

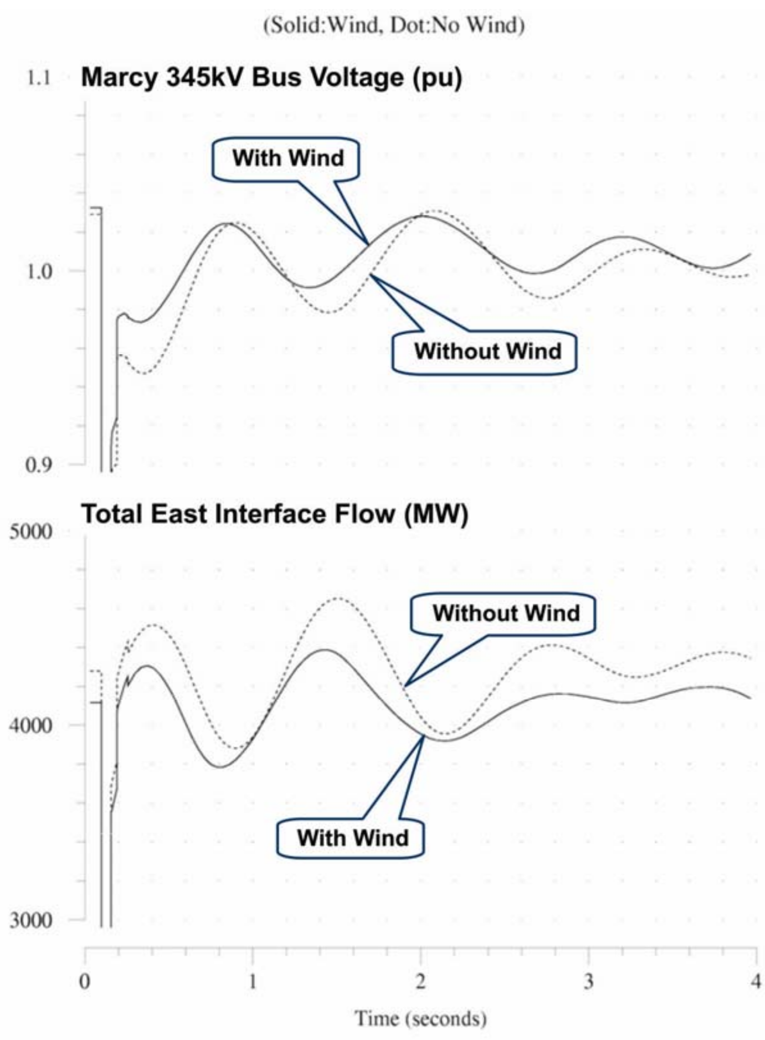


the voltage control features on a GE wind plant built recently in Colorado. In this system, voltage can be controlled across a broad range of wind conditions and power plant output. Voltage disturbances at the point of interconnection (POI) on the remote bus trigger offsetting changes in the wind plant voltage, controlling variations in the bus voltage.

Modern wind plants can be added to a power grid without degrading system performance. In fact, they can contribute to improvements in system performance. A severe test of the reliability of a system is its ability to recover from a three-phase fault at a critical point in the system. (For definitions of faults, see the Glossary in Appendix E.) System stability studies have shown that modern wind plants—equipped with power electronic controls and dynamic voltage support capabilities—can improve system performance by supporting postfault voltage recovery and damping power swings.

This performance is illustrated in Figure 4-7, which simulates a normally cleared three-phase fault on a critical 345 kV bus in the Marcy substation in central New York state (Piwko et al. 2005). The simulation assumed a 10% wind penetration (3,300 MW on a 33,000 MW system) of wind turbines with doubly fed induction

Figure 4-7. Impact of wind generation on system dynamic performance



generators. It incorporated power electronics that allowed for independent control of real and reactive power. The top half of the figure shows the quicker recovery and increased damping in the system voltage transient at the Marcy 345 kV bus. The bottom half of the figure similarly shows that the flow on the east interface has less overshoot and is more highly damped with wind. And because the power electronics capabilities of these wind turbines remain connected to the grid and respond to grid conditions with or without real power generation, they manage voltage on the grid even when the turbine is not generating power.

Utility planners use models to understand and represent the capabilities and performance of generators and transmission system assets. Detailed wind plant models that incorporate today's sophisticated wind turbine and plant control features are being used to study future system configurations, as well as to improve the power system performance of conventional technology. Wind turbine manufacturers and developers are giving a high priority to the development of improved models in response to the leadership of utility organizations such as the Western Electricity Coordinating Council (WECC). The models are critical tools that enable planners to understand wind plant capabilities and accurately determine the impact of wind plants on power system behavior.

Improved performance features are likely to be incorporated into wind models as the utility interface and control characteristics of wind turbines and wind plants continue to evolve. Variable-speed designs with power electronic controls are improving real and reactive power control within wind turbines under both transient and steady-state conditions.

4.1.4 Wind Forecasting Enhances System Operation

System operators can significantly reduce the uncertainty of wind output by using wind forecasts that incorporate meteorological data to predict wind production. Such systems yield both hour-ahead and day-ahead forecasts to support real-time operations. They also inform the scheduling and market decisions necessary for day-ahead planning.

Forecasting allows operators to anticipate wind generation levels and adjust the remainder of generation units accordingly. Piwko and colleagues (2005) found that a perfect wind forecast reduced annual variable production costs by $125 million. And a state-of-the-art forecast delivered 80% of the benefit of a perfect forecast. Improved short-term wind production forecasts let operators make better day-ahead market operation and unit-commitment decisions, help real-time operations in the hour ahead, and warn operators about severe weather events. Advanced forecasting systems can also help warn the system operator if extreme wind events are likely so that the operator can implement a defensive system posture if needed. The operating impact with the largest cost is found in the unit-commitment time frame. The seamless integration of wind plant output forecasting—into both power market operations and utility control room operations—is a critical next step in accommodating large penetrations of wind energy in power systems.

4.1.5 Flexible, Dispatchable Generators Facilitate Wind Integration

Studies and actual operating experience indicate that it is easier to integrate wind energy into a power system where other generators are available to provide balancing energy and precise load-following capabilities. In 2005, Energinet.dk published the preliminary results of a study of the impact of meeting 100% of western Denmark's annual electrical energy requirement from wind energy (Pedersen 2005). The study showed that the system could absorb about 30% energy from wind without any excess (wasted) wind production, assuming no transmission ties to outside power systems. Surplus wind energy starts to grow substantially after the wind share reaches 50%. And if wind generates 100% of the total energy demand of 26 terawatt-hours (TWh), 8 TWh of the wind generation would be surplus because it would be produced during times that do not match customer energy-use patterns. Other energy sources, such as thermal plants, would supply the deficit, including the balancing energy. In the Pedersen study, the cost of electricity doubled when wind production reached 100% of the load. The study made very conservative assumptions, however, of no external ties or market opportunities for the excess wind energy.

4.1.6 Integrating an Energy Resource in a Capacity World

Wind energy has characteristics that differ from those of conventional energy sources. Wind is an *energy* resource, not a *capacity* resource. Capacity resources are those that can be available on demand, particularly to meet system peak loads. Because only a fraction of total wind capacity has a high probability of running consistently, wind generators have limited capacity value. Traditional planning methods, however, focus on reliability and capacity planning. Incorporating wind energy into power system planning and operation, then, will require new ways of thinking about energy resources.

Traditional system planning techniques use tools that are oriented toward ensuring adequate capacity. Most transmission systems, however, can make room for additional energy resources if they allow some flexibility for interconnection and operation. This flexibility includes choice of interconnection voltage, operation as a price-taker in a spot market, and limited curtailment. Economic planning tools and probabilistic analytical methods must also be used to ensure that a bulk power system has adequate generation and transmission capacity while optimizing its use of energy resources such as wind and hydropower.

Many hydropower generators produce low-cost variable energy. Unlike wind energy, most hydropower energy can be scheduled and delivered at peak times, so it contributes greater capacity value to the system. But because the reality of droughts

Effective Load Carrying Capability (ELCC)

The ELCC is the amount of additional load that can be served at the target reliability level with the addition of a given amount of generation (wind in this case). For example, if the addition of 100 MW of wind could meet an increase of 20 MW of system load at the target reliability level, it would have an ELCC of 20 MW, or a capacity value of 20% of its nameplate value.

Consider the following example: There are 1,000 MW of wind capacity in a concentrated geographic area, with an ELCC of 200 MW or a capacity value of 20%. The peak load of the system is 5,000 MW. On the peak-load day of the year, there is a dead calm over the area, and the output of the wind plant is 0. The lost capacity is 200 MW (20% of 1,000 MW). If this system were planned with a nominal 15% reserve margin, it would have a planning reserve of 750 MW that would well exceed the reserves needed to replace the loss of the wind capacity at system peak load.

causes hydropower capacity to vary from year to year, the capacity value of this energy resource (effective load-carrying capacity [ELCC]) must be calculated using industry-standard reliability models. The capacity value is used for system planning purposes on an annual basis, not on a daily operating basis. Some combination of existing market mechanisms and utility unit-commitment processes must be used to plan capacity for day-to-day reliability.

Planning techniques for a conventional power system focus on the reliable capacity offered by the units that make up the generation system. This is essential for meeting the system planning reliability criterion, such as the loss of load probability (LOLP) of 1 day in 10 years. The ELCC of a generation unit is the metric used to determine its contribution to system reliability. It is important to recognize that wind does offer some additional planning reserves to the system, which can be calculated with a standard reliability model. The ELCC of wind generation, which can vary significantly, depends primarily on the timing of the wind energy delivery relative to times of high system risk. The capacity value of wind has been shown to range from approximately 5% to 40% of the wind plant rated capacity, as shown in Table 4-2. In some cases, simplified methods are used to approximate the rigorous reliability analysis.

Table 4-2. Methods to estimate wind capacity value in the United States

Region/Utility	Method	Note
CA/CEC	ELCC	Rank bid evaluations for RPS (20%-25%)
PJM	Peak Period	Jun-Aug HE 3 -7 p.m., capacity factor using 3-year rolling average (20%, fold in actual data when available)
ERCOT	10%	May change to capacity factor for the hours between 4 -6 p.m. in July (2.8%)
MN/DOC/Xcel	ELCC	Sequential Monte Carlo (26%-34%)
GE/NYSERDA	ELCC	Offshore/land-based (40%/10%)
CO PUC/Xcel	ELCC	PUC decision (10%), Full ELCC study using 10-year data gave average value of 12.5%
RMATS	Rule of thumb	20% for all sites in RMATS
PacifiCorp	ELCC	Sequential Monte Carlo (20%). New Z-method 2006
MAPP	Peak Period	Monthly 4-hour window, median
PGE		33% (method not stated)
Idaho Power	Peak Period	4 p.m. -8 p.m. capacity factor during July (5%)
PSE and Avista	Peak Period	The lesser of 20% or 2/3 of January Capacity Factor
SPP	Peak Period	Top 10% loads/month; 85th percentile

Reliability planning entails determining how much generation capacity of what type is needed to meet specified goals. Because wind is not a capacity resource, it does not require 100% backup to ensure replacement capacity when the wind is not blowing. Although 12,000 MW of wind capacity have been installed in the United States, little or no backup capacity for wind energy has been added to date. Capacity in the form of combustion turbines or combined cycle units has been added to meet system reliability requirements for serving load. It is not appropriate to think in terms of "backing up" the wind because the wind capacity was installed to generate, low-emissions energy, but not to meet load growth requirements. Wind power cannot replace the need for many "capacity resources," which are generators and dispatchable load that are available to be used when needed to meet peak load. If wind has some capacity value for reliability planning purposes, that should be viewed as a bonus, but not a necessity. Wind is used when it is available, and system reliability planning is then conducted with knowledge of the ELCC of the wind plant. Nevertheless, in some areas of the nation where access to generation and markets that span wide regions has not developed, the wind integration process could be more challenging. (For more information on capacity terminology, see the Glossary in Appendix E.)

Plant capacity factors illustrate the roles that different power technologies play in a bulk power system. The capacity factor (CF) of a unit measures its actual energy production relative to its potential production at full utilization over a given time period. Table 4-3 shows the capacity factors of different power plant types within the Midwest ISO for a year. The units with the highest capacity factors—nuclear (75% CF) and coal (62% and 71% CF)—are the workhorses of the system because they produce relatively low-cost baseload energy and are fully dispatchable. Wind (30% CF) and hydro (27% CF) generate essentially free energy, so the wind is taken whenever it is available (subject to transmission availability) and the hydro is scheduled to deliver maximum value to the system (to the extent possible). The plants with the lowest capacity factors (combined cycle, combustion turbines, and oil- and gas-fired steam boilers) are operated as peaking and load-following plants and essential capacity resources. As illustrated in Table 4-3, many resources in the system operate at far less than their rated capacity for much of the year, but all are necessary components of an economic and reliable system.

Table 4-3. Midwest ISO plant capacity factor by fuel type (June 2005–May 2006)

Fuel Type	**Number of Units**	**Max Capacity** (MW)	**Possible Energy** (MWh)	**Actual Energy** (MWh)	**Capacity Factor** (%)
Combined Cycle	50	12,130	106,257,048	11,436,775	11
Gas Combustion Turbine (CT)	275	21,224	185,924,868	14,749,450	8
Oil CT	187	7,488	65,595,756	2,292,288	3
Hydro	113	2,412	21,129,120	5,696,734	27
Nuclear	17	11,895	104,200,200	77,764,757	75
Coal Steam Turbine (ST; <300 MW)	230	25,432	222,786,948	137,771,172	62
Coal ST Coal (≥300 MW)	113	51,155	448,116,048	320,014,108	71
Gas ST	20	1,673	14,651,976	1,256,756	9
Oil ST	12	1,790	15,676,896	560,910	4
Other ST	10	345	3,021,324	1,722,434	57
Wind	28	1,103	9,658,776	2,882,459	30
Total	**1055**	**136,646**	**1,197,018,960**	**576,147,844**	

4.1.7 Aggregation Reduces Variability

The greater the number of wind turbines operating in a given area, the less their aggregate production variability. This is shown in Table 4-4, which gives an analysis of wind production variability as a function of an increasing number of aggregated wind turbines in a large wind plant in the Midwest (Wan 2005). Table 4-4 shows the average and standard deviation of step changes in wind plant output for different numbers of turbines over different time periods. These results indicate that wind production changes very little over short time periods. As the time period increases from seconds to minutes to hours, the output variability increases because it is driven by changes in weather patterns. In addition, as a general trend, the more wind

Table 4-4. Wind generation variability as a function of the number of generators and time interval

		14 Turbines (%)	61 Turbines (%)	138 Turbines (%)	250+Turbines (%)
1-Second Interval					
	Average	0.4	0.2	0.1	0.1
	Std. Dev.	0.5	0.3	0.2	0.1
1-Minute Interval					
	Average	1.2	0.8	0.5	0.3
	Std. Dev.	2.1	1.3	0.8	0.6
10-Minute Interval					
	Average	3.1	2.1	2.2	1.5
	Std. Dev.	5.2	3.5	3.7	2.7
1-Hour Interval					
	Average	7.0	4.7	6.4	5.3
	Std. Dev.	10.7	7.5	9.7	7.9

Note: This table compares output at the start and end of the indicated time period in terms of the percentage of total generation from each turbine group. Std. Dev. is the abbreviation for standard deviation.

turbines that are operating in a given period, the lower the production variability during that period. Simply put, system operators in the United States have found that as more wind generating capacity is installed, the combined output becomes less variable.

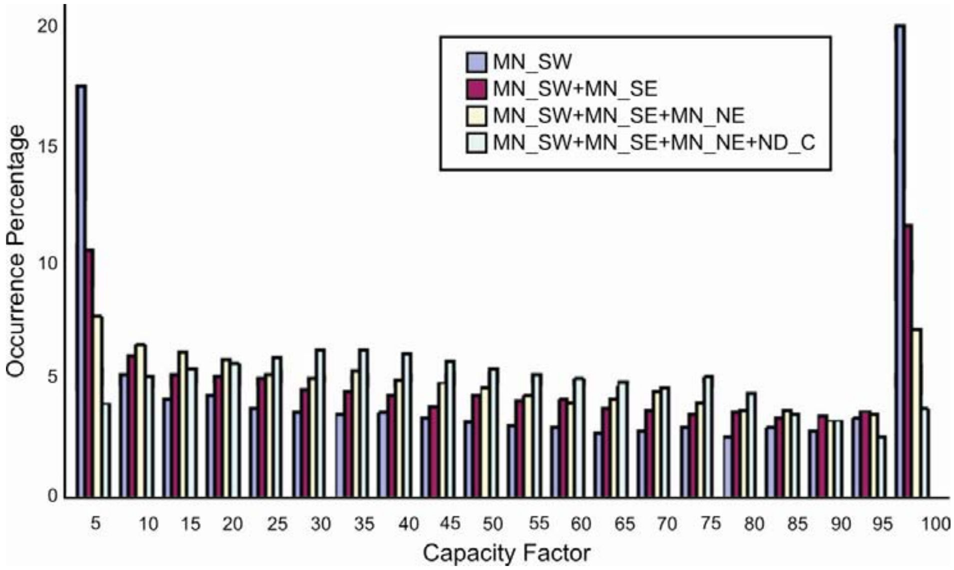
A careful evaluation of integrating wind into current operations should include a determination of the magnitude and frequency of occurrence of changes in the net load on the system during the time frames of interest (seconds, minutes, and hours). This analysis, which should be conducted both before and after the wind generation is added, will help determine the additional requirements on the balance of the generation mix.

Similarly, as more wind turbines are installed across larger geographic areas, the aggregated wind generation becomes more predictable and less variable. The benefits of geographical diversity can be seen in Figure 4-8, which shows the change in wind plant hourly capacity factor over one year for four different levels of wind plant aggregation. This figure shows the operational capacity factor of wind turbines aggregated over successively larger areas—first over southwest Minnesota, then across southwest and southeast Minnesota, then across the entire state, and finally across both Minnesota and central North Dakota. There is a decrease in the number of occurrences of very high and very low hourly capacity factors in the tails of the distribution as the degree of aggregation increases. A considerable benefit is also realized across a broad mid-range of capacity factors from 20% to 80% (EnerNex 2006).

4.1.8 Geographic Dispersion Reduces Operational Impacts

Actual wind production data and sophisticated mesoscale weather modeling techniques have shown that a sudden and simultaneous loss of all wind power on a system is not a credible event. This scenario would be prevented by spatial variations of wind from turbine to turbine in a wind plant, and to a greater degree, from plant to plant. Because of the higher capacities of existing thermal plants and

Figure 4-8. Annual hourly capacity factor



transmission lines, the loss of a wind plant will seldom be the single largest first contingency event for planning purposes. Severe weather events can lead to the loss of wind plant output as individual turbines trip off-line and/or restart as a storm front passes through. This kind of event happens on the time scale of tens of minutes to hours, however, rather than seconds.

4.1.9 Large Balancing Areas Reduce Impacts

To maintain the stable operation of the electric system, the system must instantaneously balance the amount of generation supplied and the load. If the generation and load are not in balance, the system could potentially suffer a loss of either, or lose stability and collapse. The system-balancing function is performed by authorities who operate a portion of the system called a "balancing area." (For more information on balancing areas, see the Glossary in Appendix E.) Today there are about 130 balancing areas in the U.S. grid. The largest balancing area is the PJM grid, which is part of the Eastern Interconnection, with a peak load of 145,000 MW. A small balancing area, in contrast, might be a small utility with a peak load of a few hundred MW. Balancing areas are an outgrowth of the evolution of power systems. In some areas, the current patchwork nature of the grid resulted when a number of small, isolated systems were combined into a single balancing area such as PJM.

Systems became interconnected for a number of reasons, mostly having to do with reliability and economics. Consider this example: If three adjacent systems, each with a peak load of 3,000 MW, had a single largest contingency (loss of a line or generator) of 300 MW, each would carry 300 MW of reserves. If the three systems were interconnected, and the single largest contingency was still 300 MW, each system would need only 100 MW of reserves to cover contingency reserve requirements. In this example, and as another advantage, the peak load of the combined system would be less than 9,000 MW because of diversity in the load of the three systems. Finally, operators can call on the most efficient and lowest-cost producers available across the combined system and shift production away from more-expensive units. This approach ensures that the generation mix used to meet the aggregated system's changing load is always relatively more efficient. Overall, the three interconnected systems are able to operate more efficiently at a reduced operating cost.

Wind units operate in a parallel situation across multiple balancing areas. As indicated previously, geographically dispersed wind units produce electricity more consistently and predictably. Similarly, when a system is operating across a larger area, more wind generators are available to offset customer demands, making the resulting load net of wind less variable and more predictable.

The Energy Policy Act (EPAct) of 2005 created an Electricity Reliability Organization (ERO), overseen by FERC, to enforce mandatory reliability standards, with fines for rule violations. The resulting reliability standards, implemented by NERC, include the following:

- Operator training
- Balancing authority performance criteria
- Control room situational awareness capability
- Control center hardware and software capability

These reliability requirements are likely to increase pressure on small balancing areas to consolidate. In addition to providing reliability benefits, consolidation of balancing areas would offer economic advantages because it would reduce operating costs and lower the cost of increased penetration of wind power. Virtual balancing-area consolidation can deliver the benefits of large-area aggregation without physically merging balancing areas under a single operator. Virtual consolidation can be accomplished through reserve sharing or pooling across a group of utilities, sharing of area control error (ACE) data among several balancing areas, and dynamic scheduling of wind plants from a smaller to a larger balancing area. All of these methods can help deal with the challenges of high penetrations of wind power. (For further explanation of ACE, see Appendix E.)

4.1.10 Balancing Markets Ease Wind Integration

Experience has shown that the use of well-functioning hour-ahead and day-ahead markets and the expansion of access to those markets are effective tools for dealing with wind's variability. A deep, liquid real-time market is the most economical approach to providing the balancing energy required by wind plants with variable outputs (IEA 2005). The absence of a wind production forecast introduces significant costs into the day-ahead market. As a result, wind plant participation in day-ahead markets is important for minimizing total system cost. Price-responsive load markets and associated technologies are helpful components of a well-functioning electricity market, which allows the power system to better deal with increased variability. In some regions of the United States that lack centralized markets, access to balancing and related services is being pursued through instruments such as bilateral contracts and reserve-sharing agreements.

The electricity market allows energy from all generators across the area to be dispatched based on real-time prices. When wind blows strongly, the real-time price falls, signaling more controllable generators to reduce their output and save costly fuel. Conversely, when wind drops off, real-time prices rise and dispatchable generators increase their output. As an example, the Midwest ISO covers a footprint of 15 states, so there is a deep pool of generators that can ramp up and down in response to wind output. The EnerNex (2006) study in Minnesota examined up to 25% energy penetration in the Midwest ISO market context (33% capacity penetration). The integration costs were similar to the results of a study done two years earlier (Zavadil et al. 2004) for a 15% wind capacity penetration in a structure without the regional Midwest ISO balancing market.

4.1.11 Changing Load Patterns Can Complement Wind Generation

To date, the electric system has been planned and operated under the fundamental assumption that the supply system must perfectly meet every customer's energy use, and that demand is relatively uncontrolled. But this assumption is starting to change as policy makers work to create opportunities for customers to manage their energy use in response to price signals. Wider use of price-responsive demand is expected to boost the competitiveness of wholesale electricity markets, enhance grid reliability, and improve the efficiency of resource use. Technology and regulatory options that enable customer energy management are gaining momentum because of increasing support from electricity regulators, regional transmission organizations (RTOs), and retail electricity providers.

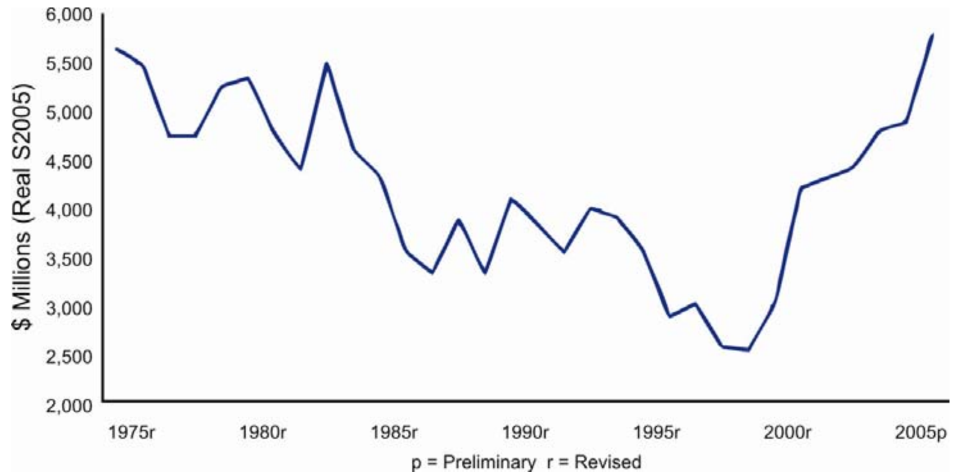
Several customer-driven energy trends could have a significant impact on wind development. Much wind generation occurs in hours when energy use is low. Two proposed off-peak electricity uses—the deployment of plug-in hybrid vehicles with off-peak charging and the production of hydrogen to power vehicles—could absorb much of this off-peak, low-cost wind generation. In addition, as more customers gain the ability to practice automated price-responsive demand or to automatically receive and respond to directions to increase or decrease their electricity use, system loads will be able to respond to, or manage, variability from wind and other energy sources.

4.2 Feasibility and Cost of the New Transmission Infrastructure Required for the 20% Wind Scenario

If the considerable wind resources of the United States are to be utilized, a significant amount of new transmission will be required. Transmission must be recognized as a critical infrastructure element needed to enable regional delivery and trade of energy resources, much like the interstate highway system supports the nation's transportation needs. Every era of new generation construction in the United States has been accompanied by new transmission construction. Federal hydropower developments of the 1930s, 1940s, and 1950s, for example, included the installation of integral long-distance transmission owned by the federal government. Construction and grid integration of large-scale nuclear and coal plants in the 1960s and 1970s entailed installing companion high-voltage interstate transmission lines, which were needed to deliver the new generation to loads. Even the natural gas plants of the 1990s, although requiring less new electric transmission, relied on expansion of the interstate gas transportation network. Significant expansion of the transmission grid will be required under any future electric industry scenario. Expanded transmission will increase reliability, reduce costly congestion and line losses, and supply access to low-cost remote resources, including renewables.

Much of the current electric grid was built to deliver power from remote areas to load centers. During the past two decades, however, investment in gas-fired generation units located closer to load centers allowed the power system to grow without investment in major new transmission (Hirst and Kirby 2001). Transmission investment lagged substantially behind that of previous decades because of uncertainty about the outcome of electricity restructuring. The average level of investment for the last half of the 1990s was under $3 billion per year, as illustrated in Figure 4-9. This amount was down from investments of approximately $5.5 billion per year in the mid 1970s (adjusted for inflation). Although transmission investment declined for two decades, it has been steadily climbing since the late 1990s .

Figure 4-9. Annual transmission investments from 1975 through 1999 and projections through 2005



Transmission investment from investor-owned utilities and independent transmission companies climbed from $3.0 billion per year in 2000 to $6.9 billion in 2006 (Eisenbrey 2007). Nearly $8 billion of investment is expected in 2007, with the figure growing to $8.4 billion in 2009. The steady increase in new transmission investment reflects not only a catch-up in local transmission, but new commitments to backbone transmission systems for major new generation, intra- and inter-regional trade, and increased reliability.

The 20% Wind Scenario would require continued transmission investment. Many new transmission infrastructure studies, plans, and projects are already under way. Current or recent activities include the following:

- Planning by the Western Governors' Association's (WGA) Clean and Diversified Energy Advisory Committee (CDEAC 2006)
- The collaboration of Minnesota utilities in the Capital Expansion Plan for 2020 (CapX 2020)
- The creation of Competitive Renewable Energy Zones (CREZ) by the state legislature in Texas (ERCOT 2006)
- The creation of state transmission or infrastructure authorities in Wyoming, Kansas, South Dakota, New Mexico, and Colorado
- The proliferation of large interstate transmission projects in the West (WIEB 2007)
- The SPP "X Plan" and Extra High Voltage analysis (SPP)

- The Midwest ISO *Transmission Expansion Plan 2006* (Midwest ISO 2006).

4.2.1 A New Transmission Superhighway System Would Be Required

Wind energy development requires two types of transmission. Trunk-line transmission runs from areas with high-quality wind resources and often carries a high proportion of energy from wind and other renewable sources. Backbone high-voltage transmission runs across long distances to deliver energy from production areas to load centers. These superhighways mix power from many generating areas, sources, and shippers—just as a highway carries all types of vehicles traveling a range of distances.

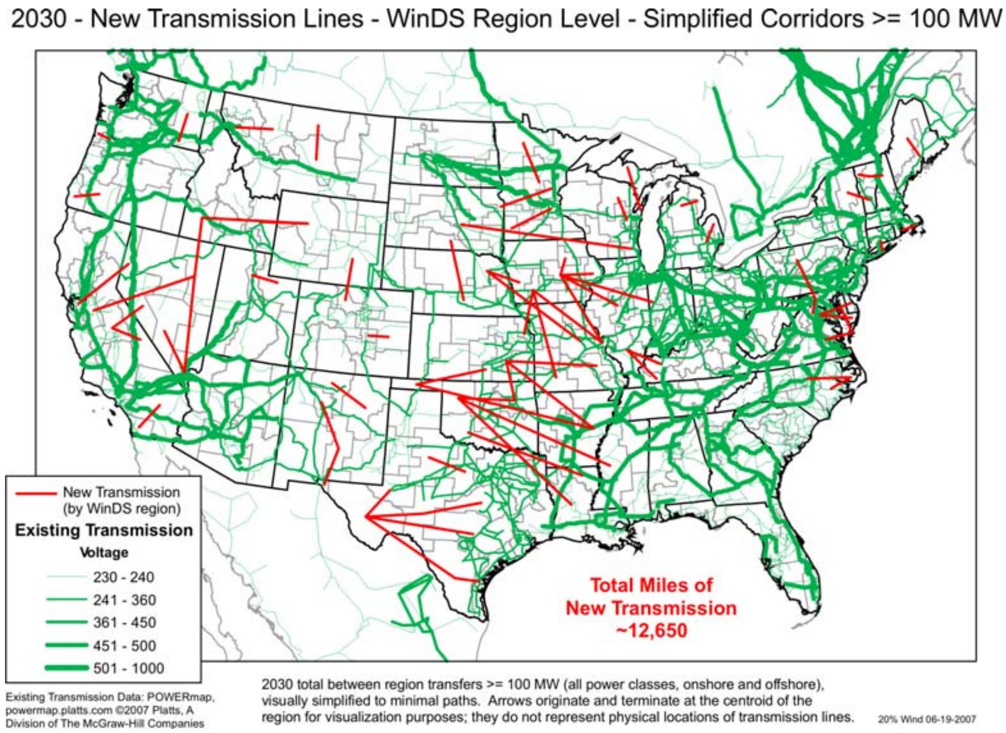
To determine how much transmission would be needed for the 20% Wind Scenario, the National Renewable Energy Laboratory's (NREL) Wind Deployment System (WinDS) model was used (see Appendices A and B). The approach, described in Appendices A and B, used the WinDS model to determine distances from the point of production to the point of consumption, as well as the cost-effectiveness of building wind plants close to load or in remote locations and paying the transmission cost. To account for the cost of transmission that would be required by coal and other resources, the analysis added the typical cost of transmission needed to interconnect those resources to the capital cost. This method, although providing balance in the overall cost assessment, is only a first step. More work must be done in regional transmission planning processes to evaluate the transmission required for the desired portfolio of resources.

When determining whether it is more efficient to site wind projects close to load or in higher quality wind resource areas that are remote from load and require transmission, the WinDS optimization model finds that it is often more efficient to site wind projects remotely. In fact, the model finds that it would be cost-effective to build more than 12,000 miles of additional transmission, at a cost of approximately $20 billion in net present value terms. Much of that transmission would be required in later years after an initial period in which generation is able to use the limited remaining capacity available on the existing transmission grid. The transmission required for the 20% Wind Scenario can be seen in the red lines on the map in Figure 4-10. The red lines represent general areas where new transmission capacity would be needed. The existing transmission grid illustrated by green lines. As a point of comparison, more than 200,000 miles of transmission lines are currently operating at 230 kV and above.

This analytical approach is consistent with other recent or current studies and plans, such as the following:

- The CDEAC evaluated a "high renewables" case and found that it would require an additional 3,578 line miles of transmission at a total cost of $15.2 billion (CDEAC 2006). This transmission investment would access 68.4 GW of renewable generation (predominantly wind) and 84.6 GW of new fossil fuel generation. Under the CDEAC analysis, if half of the transmission cost is assigned to wind, the resulting cost would be approximately $120 per new kilowatt of wind developed. This represents about a 7% increase in the capital cost of wind development (based on capital costs for a wind energy facility of about $1,800/kW).

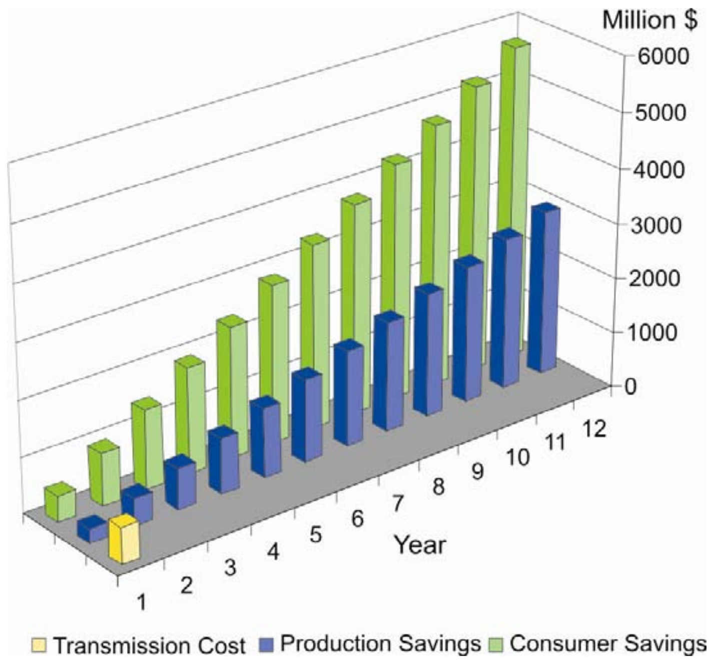
Figure 4-10. Conceptual new transmission line scenario by WinDS region



- The Midwest ISO compared the benefits and costs of bringing 8,640 MW of new wind energy online. Using a natural gas price of $5 per million British thermal units (MMBtu; well below 2007 prices), the annual benefits of reduced natural gas costs from new transmission and development of wind generation were between $444 and $478 million (Midwest ISO 2003). The Midwest ISO recently studied the costs of developing 16,000 MW of wind within its system, along with 5,000 miles of new 765 kV transmission lines to deliver the wind from the Dakotas to the New York City area. Although the overall generation and transmission costs reached an estimated investment of $13 billion, the project produced annual savings of $600 million over its costs. These savings are in the form of lower wholesale power costs and prices in the eastern part of the Midwest ISO footprint—such as Ohio and Indiana—resulting from greater access to lower-cost generation in western states such as Iowa and the Dakotas.
- AEP, a large utility and transmission owner/operator, produced a conceptual transmission plan to integrate 20% electricity from wind. The conceptual plan provides for 19,000 miles of new 765 kV transmission line at a discounted or net present value cost of $26 billion. This estimate is close to the WinDS model estimate (AEP 2007).
- ERCOT, the independent transmission operator for most of Texas, evaluated 12 options to build transmission for additions of 1,000 MW to 4,600 MW of wind energy. ERCOT found that the transmission addition would cost between $15 million and $1.5 billion, depending on the distance required. The transmission cost averages $180/kW of wind energy, or about 10% of the $1,800/kW

capital cost (ERCOT 2006). The benefits available from such transmission are often reported in terms of annual savings to consumers and the reduced cost of energy production. The graph in Figure 4-11 illustrates the cumulative benefits in the Texas study, for the weakest investment of the 12 analyzed by ERCOT. It should be noted that wind transmission cost estimates remain highly uncertain. For example, ERCOT recently updated their earlier study and found that for additions of 5,150 MW to 18,000 MW of wind energy, the transmission addition would cost between $2.95 billion and $6.38 billion, or in the range of $350/kW to $570/kW (ERCOT 2008).

Figure 4-11. Cumulative savings versus total transmission cost for renewable energy zone (worst case)



Source: ERCOT (2006)

- In another study analyzing transmission costs, the CDEAC Wind Task Force used NREL's WinDS geographic information system (GIS) database to create wind energy supply curves for many states in the western United States. This analysis showed that the western states can build 30 GW of wind capacity that can be delivered at a price of $50/MWh (counting both generation and transmission costs). Building additional transmission to reach more wind resources and more loads would raise the marginal cost by 20% to $60/MWh. More than 100 GW of new wind capacity could be developed at that price, using 2005 equipment costs (CDEAC 2006).

Clearly, significant additional transmission capacity would be required to integrate high levels of wind across the country. As the studies described here demonstrate, however, meeting this challenge could be economically and technically feasible. In addition, sizable net reductions in the cost of delivering bulk electricity to load centers could be achievable.

Developing any major new generation sources in remote or semiremote locations will require new transmission to deliver the energy to loads. As long as load continues to grow, investment in transmission will be needed as well. Most high-voltage transmission additions serve multiple generation resources, not just wind. Once the marginal transmission cost for wind is balanced against its low energy cost and environmental impacts, the net costs might turn out to be not much greater in the portfolio context than the transmission costs of traditional fossil fuel resources.

An investment of approximately $60 billion (in undiscounted terms) in transmission between now and 2030, as suggested by the NREL analysis, amounts to an expenditure of approximately $3 billion per year over the next 22 years. Current transmission investment level is nearly $8 billion per year and growing. Regardless of wind's role, most analysts believe that this figure will continue to increase as utilities make up for decades of underinvestment in the grid. As long as electricity demands grow, new transmission will be required to serve any new generation developed, and incremental transmission costs will be unavoidable.

4.2.2 Overcoming Barriers to Transmission Investment

Barriers to transmission investment include:

- Transmission planning
- Allocation of the costs of new transmission investments
- Assurance of cost recovery
- Siting of new transmission facilities

More details on each area are given in the following subsections.

Transmission Planning

Generation companies are currently reluctant to commit to a new generation project unless it is clear that transmission will be available, but transmission developers are equally reluctant to step forward until generator interconnection requests have been filed (hence, transmission planning has its own "chicken or the egg" conundrum). Most electric utilities planned generation and transmission in an integrated process until the 1990s, when federal open access rules required the separation of transmission and generation businesses. The effects of this separation on planning can be reduced through open, transparent transmission planning processes, which are now required by FERC's recently enacted ruling, Order No. 890 (FERC 2007).

The 20% Wind Scenario would require a generic change in the way transmission planning is done in many areas of the country. Numerous parties across a wide geographic area would need to collaborate on developing a common plan, instead of individual entities planning in isolation. This approach yields major economies of scale in that all users would benefit by pooling solutions to their needs into a single plan that would be more productive (in regional terms) than simply summing the needs of individual organizations. FERC's Order No. 890 is a large step toward this regional joint planning approach, but success will depend on collaborative follow-through at the regional level.

Cost Allocation

Transmission is often a "public good"— meaning that its benefits are widely dispersed and that some parties can enjoy these benefits without incurring direct costs. In such situations, parties might have incentives to avoid paying their fair share of the costs. Accordingly, public good status cannot be achieved unless some government agency determines how the costs are to be allocated and is able to enforce that allocation.

Under the Federal Power Act, FERC is responsible for determining how transmission costs are to be allocated. For regions with RTOs or ISOs, FERC has typically reviewed generic cost-allocation plans proposed by these organizations and approved the plans with modifications. In areas without RTOs or ISOs, prospective transmission developers propose cost-allocation arrangements to FERC on a project-by-project basis. FERC reviews the proposals; calls for additional information if needed; and either approves them, rejects them, or approves them with certain conditions attached.

Creating Renewable Energy Models for New Transmission

A few states that have good wind resources and RPS laws have decided to expand their states' transmission in advance of generation to enable the modular development of location-constrained, clean, and diversified resource areas to meet state goals. Texas, Minnesota, Colorado, and California, for example, are leaders in renewable energy development, and have created renewable energy models for new transmission. North Dakota, South Dakota, Wyoming, Kansas, and New Mexico have also established new authorities to spur investment in additional transmission infrastructure.

Cost Recovery

A new transmission facility, regardless of need or merit, will not be built until the participating utilities (and the financial community) have a very high degree of certainty that the cost of the facility will be recoverable in a predictable manner. FERC and state regulatory approval of a cost-allocation plan and a rate of return on the investment are essential.

Transmission Siting

Local opposition to proposed transmission lines is often a major challenge to transmission expansion. An AC transmission line typically benefits all users along its path by increasing reliability, allowing for new generation and associated economic development, and providing access to lower-cost resources. Local owners, however, do not always value such benefits and frequently have other concerns that must be addressed. Some transmission companies have been more effective than others at obtaining local input, identifying and dealing with landowners' concerns, and selecting routes. Best practices in this area need to be identified and broadly applied.

State agencies sometimes reject interstate transmission proposals if it appears that they would not result in significant benefits for intrastate residents. This concern led the U.S. Congress to include a provision in the 2005 EPAct that establishes a federal "backstop" transmission siting authority, which can be invoked if the U.S. Department of Energy (DOE) has designated the relevant geographic area as a "national interest electric transmission corridor" (i.e., a "national corridor"), and an affected state has withheld approval of a proposed transmission facility in the national corridor for more than one year.

4.2.3 Making a National Investment in Transmission

The 20% Wind Scenario would require widespread recognition that there is national interest in ensuring adequate transmission. Expanding the country's transmission infrastructure would support the reliability of the power system; enable open, fair, and competitive wholesale power markets; and grant owners and operators access to low-cost resources. Although built to enable access to wind energy, the new transmission infrastructure would also increase energy security, reduce GHG emissions, and enhance price stability through fuel diversity.

4.3 U.S. Power System Operations and Market Structure Evolution

4

The lessons summarized from research done to date illustrate a number of changes that would facilitate reaching 20% wind energy penetration. Expanding from approximately 12 GW at the time of this writing to over 300 GW will require most or all of these changes. This section summarizes the operational and market features that would support the 20% Wind Scenario. These features are also important to the long-term sustainability of the electric industry.

4.3.1 Expanding Market Flexibility

The 20% Wind Scenario would be aided by the development of or access to energy spot markets where participants who have an excess or shortfall of power could trade at competitive prices that reflect the marginal cost of balancing load. Such markets were recently implemented in the 15-state Midwest ISO region, the mid-Atlantic PJM region, New York, New England, and the Southwest Power Pool (SPP), showing the feasibility of such reforms. It is certainly possible that other regions could pursue such reforms by 2030.

Broad geographical markets and inter-area trading would allow the benefits of geographic dispersion and aggregation of wind plant output to be realized. These benefits have been shown to reduce the variability of wind plant output on a large scale, which makes a market-based approach and trading system all the more worthwhile. The challenge is that energy spot markets have been subject to opposition as market prices have risen because of higher fuel costs.

4.3.2 Enhancing Wind Forecasting and System Flexibility

The 20% Wind Scenario would require highly trained power system operators, equipped with state-of–the-art wind resource forecasting tools that would be fully integrated with power system operations. Forecasting is spreading rapidly and improving significantly, particularly in terms of its adoption and integration within power system operations. Some power system dispatchers, however, still need to be trained to operate systems with high wind penetration and to use forecasting and operations tools that predict and respond to wind plant output fluctuations.

To achieve balance in a power system using wind energy, the 20% Wind Scenario would require the use of the existing fleet of flexible, dispatchable, mainly gas-fired generators designed for frequent and rapid ramping. There would need to be enough dispatchable units to balance the system as fluctuations occur in wind plant output and load.

Transmission services vary across regions in the United States. Regions with RTOs have "financial transmission rights" that are more flexible than capacity reservations and allow for payment based on usage. In addition, under FERC Order 890 (FERC 2007), all regions are now required to develop "conditional firm" services, which would allow for resources such as wind to be better integrated into the grid.

The 20% Wind Scenario would require end users to be able (via price signals and technology) to respond to system needs by shifting or curtailing consumption. Time-shifting of demand would help reduce today's large difference between peak and off-peak loads and encourage more flexible loads (such as plug-in hybrid cars, hydrogen production, and smart appliances) that take energy from the grid during low-load periods. These practices would smooth electricity demand and open a larger market for off-peak wind energy.

The 20% Wind Scenario would require a smarter, more flexible, and more robust high-voltage transmission grid than the one in place today. Greater reliance on flexible AC transmission system (FACTS) devices and wide-area monitoring and control systems would be necessary. Increased flexibility would accommodate variations in technology choices, resource mixes, market rules, and regional characteristics. Greater robustness would help ensure future reliability. Information technologies for distributed intelligence, sensors, smart systems, controls, and distributed energy resources would need to be standardized and integrated with market and customer operations.

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Chapter 5. Wind Power Siting and Environmental Effects

The 20% Wind Scenario offers substantial positive environmental impacts in today's carbon-constrained world. Wind plant siting and approval processes can accommodate increased rates of installation while addressing environmental risks and concerns of local stakeholders.

5

5.1 Wind Energy Today

Wind energy is one of the cleanest and most environmentally neutral energy sources in the world today. Compared to conventional fossil fuel energy sources, wind energy generation does not degrade the quality of our air and water and can make important contributions to reducing climate-change effects and meeting national energy security goals. In addition, it avoids environmental effects from the mining, drilling, and hazardous waste storage associated with using fossil fuels. Wind energy offers many ecosystem benefits, especially as compared to other forms of electricity production. Wind energy production can also, however, negatively affect wildlife habitat and individual species, and measures to mitigate prospective impacts may be required. As with all responsible industrial development, wind power facilities need to adhere to high standards for environmental protection.

Wind energy generally enjoys broad public support, but siting wind plants can raise concerns in local communities. Successful project developers typically work closely with communities to address these concerns and avoid or reduce risks to the extent possible. Not all issues can be fully resolved, and not every prospective site is appropriate for development, but engaging with local leaders and the public is imperative. Various agencies and stakeholders must also be involved in reviewing and approving projects. If demand increases and annual installations of wind energy approach 10 gigawatts (GW) and more, the wind energy industry and various government agencies would need to scale up their permitting and review capabilities.

To date, hundreds of wind projects have been successfully permitted and sited. Although the wind energy industry must continue to address significant environmental and siting challenges, there is growing market acceptance of wind energy. If challenges are resolved and institutions are adaptive, a 20% Wind Scenario in the United States could be feasible by 2030. As noted by the Intergovernmental Panel on Climate Change (IPCC), under certain conditions, renewable energy could contribute 30% to 35% of the world's electricity supply by 2030 (IPCC 2007).

This chapter reviews environmental concerns associated with siting wind power facilities, public perceptions about the industry, regulatory frameworks, and potential approaches to addressing remaining challenges.

5.1.1 SITE-SPECIFIC AND CUMULATIVE CONCERNS

About 10% to 25% of proposed wind energy projects are not built—or are significantly delayed—because of environmental concerns. Although public support for wind energy is generally strong, this attitude does not always translate into early support for local projects. Site-specific concerns often create tension surrounding new energy facilities of any kind. Although most wind energy installations around the United States pose only minor risks to the local ecology or communities, some uncertainties remain. Further research and knowledge development will enable some of these uncertainties to be mitigated and make risks more manageable.

Local stakeholders generally want to know how wind turbines might affect their view of their surroundings and their property values. In addition, they might be concerned about the impact on birds and other wildlife. Weighing these risks and benefits raises questions about the best management approaches and strategies.

Wind energy developments usually require permits or approvals from various authorities, such as a county board of supervisors, a public service commission, or another political body (described in more detail in Section 5.5). These entities request information from a project developer—usually in the form of environmental impact studies before construction—to understand potential costs and benefits. The results of these studies guide jurisdictional decisions. A single lead agency might consider the entire life-cycle effects of a wind energy project. This is in contrast to fossil fuel and nuclear projects, in which the life-cycle impacts (e.g., acid rain and nuclear wastes) would be widely dispersed geographically. No single agency considers all impacts.

For many government agency officials, the central issue is whether wind energy projects pose risks to the resources or environments they are required to protect. Officials want to know the net cumulative environmental impact (i.e., emissions reductions versus wildlife impacts) of using 20% wind power in the United States, whether positive or negative. Uncertainty can arise from inadequate data, modeling limitations, incomplete scientific understanding of basic processes, and changing societal or management contexts. Complex societal decisions about risk typically involve some level of uncertainty, however, and very few developers make decisions with complete information (Stern and Fineberg 1996). Because a great deal of experience exists to inform decision making in such circumstances, residual uncertainties about environmental risks need not unduly hinder wind energy project development.

The wind industry may encounter difficulties entering a competitive energy marketplace if it is subject to requirements that competing energy technologies do not face. Risks associated with wind power facilities are relatively low because few of the significant upstream and downstream life-cycle effects that typically characterize other energy generation technologies are realized. Moreover, the potential risks are not commensurate when comparing wind energy and other sources (such as nuclear and fossil fuels), and comparative impact analyses are not readily available. These analyses would need to examine the broader context of the potential adverse effects of wind power on human health and safety (minimal), ecology, visibility, and aesthetics in relation to the alternatives.

The acceptability of risks will vary among communities and sites, so it is important to understand these differences and build broad public engagement. Developing effective approaches to gaining the public's acceptance of risks is a necessary first step toward siting wind energy facilities.

5.2 ENVIRONMENTAL BENEFITS

5.2.1 GLOBAL CLIMATE CHANGE AND CARBON REDUCTIONS

Publicity related to wind power developments often focuses on wind power's impact on birds, especially their collisions with turbines. Although this is a valid environmental concern that needs to be addressed, the larger effects of global climate change also pose significant and growing threats to birds and other wildlife species. The IPCC recently concluded that global climate change caused by human activity is likely to seriously affect terrestrial biological systems, as well as many other natural systems (IPCC 2007). A 2004 study in *Nature* forecast that a mid-range estimate of climate warming could cause 19% to 45% of global species to become extinct. Even with minimal temperature increases and climate changes, the study forecast that extinction of species would be in the 11% to 34% range (Thomas et al. 2004). The future for birds in a world of global climate change is particularly bleak. A recent article found that 950 to 1,800 terrestrial bird species are imperiled by climate changes and habitat loss. According to the study, species in higher latitudes will experience more effects of climate change, while birds in the tropics will decline from continued deforestation, which exacerbates global climate change and land conversion (Jetz, Wilcove, and Dobson 2007). Wind energy, which holds significant promise for reducing these impacts, can be widely deployed across the United States and around the world to begin reducing greenhouse gas emissions (GHGs) now. Although the effects of wind energy development on wildlife should not be minimized, they must be viewed in the larger context of the broader threats posed by climate change.

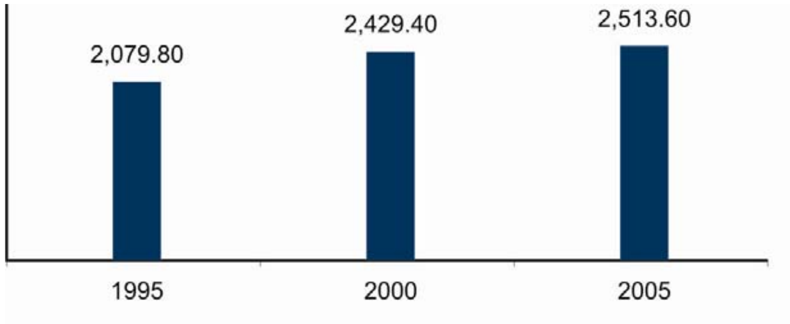
Compared with the current U.S. average utility fuel mix, a single 1.5 MW wind turbine displaces 2,700 tons of CO_2 per year, or the equivalent of planting 4 square kilometers of forest every year (AWEA 2007).

A primary benefit of using wind-generated electricity is that it can play an important role in reducing the levels of carbon dioxide (CO_2) emitted into the atmosphere. Wind-generated electricity is produced without emitting CO_2, the GHG that is the major cause of global climate change.

Today, CO_2 emissions in the United States approach 6 billion metric tons annually, 39% of which are produced when electricity is generated from fossil fuels (see Figure 5-1; EIA 2006). If the United States obtained 20% of its electricity from wind energy, the country could avoid putting 825 million metric tons of CO_2 annually into the atmosphere by 2030, or a cumulative total of 7,600 million metric tons by 2030 (see assumptions outlined in Appendices A and B).

A relatively straightforward metric used to understand the carbon benefits of wind energy is that a single 1.5 MW wind turbine displaces 2,700 metric tons of CO_2 per year compared with the current U.S. average utility fuel mix, or the equivalent of planting 4 square kilometers of forest every year (AWEA 2007).

Figure 5-1. Electricity production is responsible for 39% of CO_2 emissions in the United States



Source: EIA (2006)

The fuel displaced by wind-generated electricity depends on the local grid and the type of generation supply. In most places, natural gas is the primary fuel displaced. Wind energy can displace coal on electric grids with large amounts of coal-fired generation. In the future, wind energy is likely to offset more coal by reducing the need to build new coal plants. Regardless of the actual fuel supplanted, more electricity generated from wind turbines means that other nonrenewable, fossil-based fuels are not being consumed. In New York, for example, a study prepared for the independent system operator (ISO) found that if wind energy provided 10% of the state's peak electricity demand, 65% of the energy displaced would be from natural gas, followed by coal at 15%, oil at 10%, and electricity imported from out of state at 10% (Piwko et al. 2005).

In addition, manufacturing wind turbines and building wind plants together generate only minimal amounts of CO_2 emissions. One university study that examined the issue (White and Kulsinski 1998) found that when these emissions are analyzed on a life-cycle basis, wind energy's CO_2 emissions are extremely low—about 1% of those from coal, or 2% of those from natural gas, per unit of electricity generated. In other words, using wind instead of coal reduces CO_2 emissions by 99%; using wind instead of gas reduces CO_2 emissions by 98%.

5.2.2 Improving Human Health through Reduced Air Emissions

Switching to a zero-emissions energy-generation technology like wind power contributes to cleaner and healthier air. Moreover, wind power generation is not a direct source of regulated pollutants such as nitrogen oxides, sulfur dioxide, and mercury.

Coal-fired power plants are the largest industrial source of mercury emissions in the United States (NESCAUM 2003). The U.S. Environmental Protection Agency (EPA) (EPA 2007) and the American Medical Association (AMA) note that fetal exposure to methylmercury has been linked to problems with neurological development in children (AMA Council on Scientific Affairs 2004).

Furthermore, according the American Lung Association (ALA), almost half of all Americans live in counties where unhealthy levels of smog place them at risk for decreased lung function, respiratory infection, lung inflammation, and aggravation of respiratory illness. And more than 76.5 million Americans are exposed to unhealthful short-term levels of particle pollution, which has been shown to increase heart attacks, strokes, emergency room visits for asthma and cardiovascular disease, and the risk of death. Some 58.3 million Americans suffer from chronic exposure to particle pollution. Even when levels are low, exposure to these particles can also increase the risk of hospitalization for asthma, damage to the lungs, and the risk of premature death (ALA 2005).

5.2.3 Saving Water

The nation's growing communities place greater demands on water supplies and wastewater services, and more electricity is needed to power the expanding water services infrastructure. Future population growth in the United States will heighten competition for water resources. Especially in arid regions, communities are increasingly facing challenges with shortages of water and electric power, resources that are interlinked.

Water is a critical resource for thermoelectric power plants, which use vast quantities. These plants were responsible for 48% of all total water withdrawals in 2000, or about 738 billion liters per day (Hutson et al. 2005). Much of the water withdrawn from streams, lakes, or other sources is returned, but about 9%—totaling about 68 billion liters per day—is consumed in the process. Although regulation will require the majority of new generation plants to use recirculating, closed-loop cooling technologies, which will lessen water withdrawals, this evolution will actually lead to an overall increase in water consumption (DOE 2006).

Even some renewable technologies place a demand on water resources. For example, most ethanol plants have demonstrated a reduction in water use over the past years, but are still in the range of 13.25 to 22.7 liters of water consumed per 3.79 liters of ethanol produced (IATP 2006).

In contrast, wind energy does not require the level of water resources consumed by many other kinds of power generation. As a result, it may offer communities in water-stressed areas the option of economically meeting growing energy needs without increasing demands on valuable water resources. Wind energy can also provide targeted energy production to serve critical local water system needs such as irrigation and municipal systems.

Wind energy has the potential to conserve billions of liters of water in the interior West, which faces declining water reservoirs.

In a nongovernmental organization report entitled *The Last Straw: Water Use by Power Plants in the Arid West,* Baum and colleagues (2003) called attention to water quality and supply issues associated with fossil-fuel power plants in the interior West. Faced with water shortages, the eight states in this region are seeing water for power production compete with other uses, such as irrigation, hydropower, and municipal water supplies. Based on this analysis, the authors estimate that significant savings from wind energy are possible, as illustrated in Table 5-1.

As the United States seeks to lessen the use of foreign oil for fuel, water use and consumption is high among other energy production methods. Most ethanol plants have demonstrated a reduction in water use in recent years, but are still in the range of 13.25 to 22.7 liters of water consumed per 3.79 liters of ethanol produced (IATP 2006). An issue brief, prepared by the World Resources Institute, stated that coal-to-

Table 5-1. Estimated water savings from wind energy in the interior West (Baum et al. 2003)

Wind Energy (MW)	**Water Savings** (billion gallons withdrawn)	**Water Savings** (billion gallons consumed)
1,200	3.15	1.89
3,000	7.88	4.73
4,000	10.51	6.31

Adapted from *The Wind/Water Nexus: Wind Powering America* (DOE 2006)

liquid fuel production is a water-intensive process, requiring about 10 gallons of water use for every gallon of coal-to-liquid product (Logan and Venezia 2007).

5

Global climate change is also expected to impact water supplies. Mountains in the western United States will have less snowpack, more winter flooding, and reduced flows in the summer, all of which worsen the already fierce competition for diminished water resources (IPCC 2007). Because of increasing demand for water and decreasing supplies, some tough decisions will be needed about how this valuable resource should be allocated—especially for the West and Great Plains. Although wind energy cannot solve this dilemma, an increased reliance on wind energy would alleviate some of the increased demand in the electricity sector, thereby reducing water withdrawals for the other energy sources.

5.3 POTENTIAL ENVIRONMENTAL IMPACTS

5.3.1 HABITAT DISTURBANCE AND LAND USE

Fuel extraction and energy generation affect habitat and land use, regardless of the type of fuel. Traditional electricity generation requires mining for coal or uranium and drilling for natural gas, all of which can destroy habitat for many species and cause irreversible ecological damage. With the global and national infrastructure required to move fuel to generating stations—and the sites needed to store and treat the resulting waste—processing fossil fuel and nuclear energy is also a highly land-intensive endeavor.

Coal mining is estimated to disturb more than 400,000 hectares[11] of land every year for electricity generation in the United States, and it destroys rapidly disappearing wildlife habitat. In the next 10 years, more than 153,000 hectares of high-quality mature deciduous forest are projected to be lost to coal mining in West Virginia, Tennessee, Kentucky, and Virginia, according to the National Wildlife Federation (Price and Glick 2002).

Wind development also requires large areas of land, but the land is used very differently. The 20% Wind Scenario (305 GW) estimates that in the United States, about 50,000 square kilometers (km^2) would be required for land-based projects and more than 11,000 km^2 would be needed for offshore projects. However, the footprint of land that will actually be disturbed for wind development projects under the 20% Wind Scenario ranges from 2% to 5% of the total amount (representing land needed

[11] One hectare = 2.47 acres

for the turbines and related infrastructure). Thus the amount of land to be disturbed by wind development under the 20% Wind Scenario is only 1,000 to 2,500 km^2 (100,000 to 250,000 hectares)—an amount of dedicated land that is slightly smaller than Rhode Island. For scale comparisons, available data for existing coal mining activities indicate that about 1,700,000 hectares of land is permitted or covered and about 425,000 hectares of land are disturbed (DOI 2004). An important factor to note is that wind energy projects use the same land area each year; coal and uranium must be mined from successive areas, with the total disturbed area increasing each year. In agricultural areas, land used for wind generation projects has the potential to be compatible with some land uses because only a few hectares are taken out of production, and no mining or drilling is needed to extract the fuel.

Although wind energy may be able to coexist with land uses such as farming, ranching, and forestry, wind energy development might not be compatible with land uses such as housing developments, airport approaches, some radar installations, and low-level military flight training routes. Wind turbines are tall structures that require an otherwise undisturbed airspace around them. The need for relatively large areas of undisturbed airspace can also directly or indirectly affect wildlife habitat.

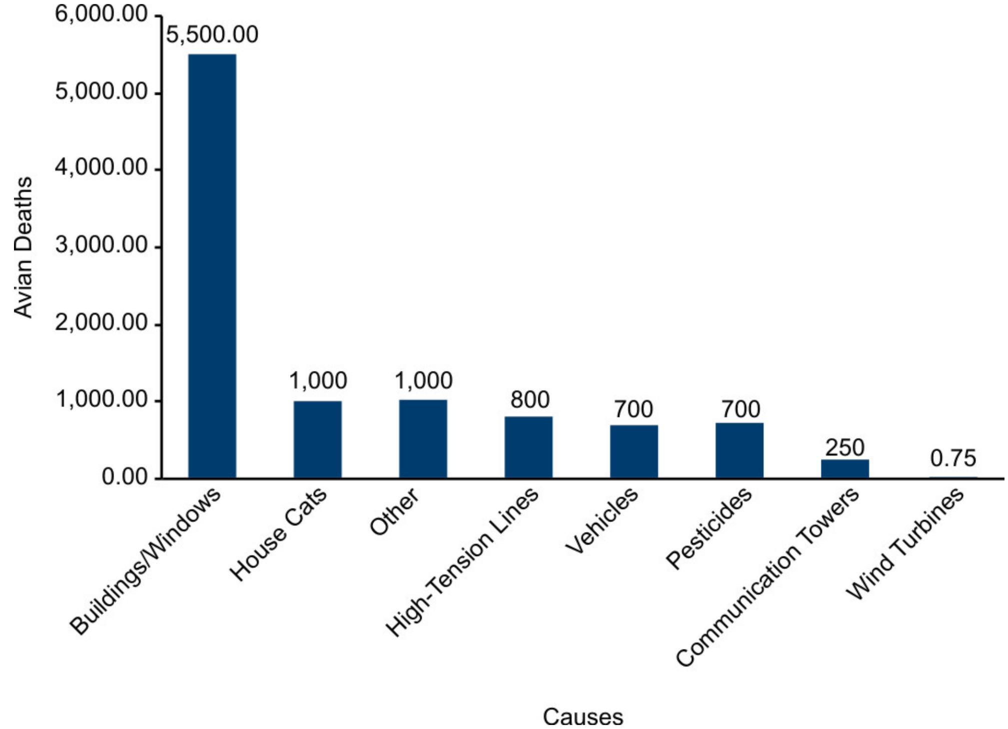
In a presentation to the National Wind Collaborative Committee, wildlife biologists describe direct construction impacts that include building wind turbines, service roads, and other infrastructure (such as substations). Estimates of temporary construction impacts range from 0.2 to 1.0 hectare per turbine; estimates of permanent habitat spatial displacement range from 0.3 to 0.4 hectare per turbine (Strickland and Johnson 2006). Indirect impacts can include trees being removed around turbines, edges in a forest being detrimental to some species, and the presence of turbines causing some species or individuals to avoid previously viable habitats. For example, a grassland songbird study on Buffalo Ridge in Minnesota found species displacement of 180 meters (m) to 250 m from the wind turbines (Strickland and Johnson 2006).

Indirect habitat impacts on grassland species are a particular concern, especially because extensive wind energy development could take place in grassy regions of the country. Peer-reviewed research has concluded, however, that one species, the Lesser Prairie Chicken, actively avoids electricity infrastructure such as transmission lines and frequent vehicle activity by as much as 0.4 km, and fossil fuel power plants by more than 1 km (Robel et al. 2004). Displacements of already declining local populations are likely, but the magnitude of these effects is uncertain because data specific to wind energy are not yet available. The extent of unknowns surrounding this issue led the National Wind Collaborative Committee (NWCC) Wildlife Workgroup to form the Grassland/Shrub-Steppe Species Collaborative (GS3C), a four-year research program to study the effects of wind turbines on grassland birds (NWCC 2006). Like the Bat and Wind Energy Cooperative (BWEC) discussed later, the GS3C provides a vehicle for public and private funding and for third-party peer-reviewed studies. Issues regarding the conservation of sensitive habitats will need to be addressed over time. Strategic planning and siting to conserve and improve potentially high-value habitat can be constructive and beneficial for both wind energy and wildlife.

5.3.2 Wildlife Risks

Wildlife—and birds in particular–are threatened by numerous human activities, including effects from climate change. Relative to other human causes of avian mortality, wind energy's impacts are quite small. Figure 5-2 puts the wind industry's

Figure 5-2. Anthropogenic causes of bird mortality
(per 10,000 avian deaths)



Source: Erickson et al. (2002)

impacts into context and illustrates that many human (and some feline) activities pose risks to birds.

As Figure 5-2 shows, anthropogenic causes of bird fatalities range from 100 million to 1 billion annually. Currently, it is estimated that for every 10,000 birds killed by all human activity, less than one death is caused by wind turbines. In fact, a recent National Research Council (NRC 2007) study concluded that current wind energy generation is responsible for 0.003% of human-caused avian mortality. Even with 20% wind energy, turbines are not expected to be responsible for a significant percentage of avian mortality as long as proper precautions are taken in siting and design.

Further comparative analyses are needed to better understand the trade-offs with other energy sources. Avian mortality is also caused, for example, by oil spills, oil platforms built on bird migration routes along the Gulf Coast, acid rain, and mountaintop mining. Wind energy will likely continue to be responsible for a comparatively small fraction of total avian mortality risks, although individual sites can present more-localized risks. Some data relative to specific sites are offered in the list that follows:

- The first large-scale commercial wind resource area developed in the world was Altamont Pass in California's Bay Area in the 1980s. The Altamont Pass development has seen high levels of bird kills, specifically raptors. Although this facility has been problematic, it remains an anomaly relative to other wind energy projects. In January 2007, a number of the parties involved agreed to take steps to reduce raptor fatalities and upgrade the project area with newer technology.

- An NWCC fact sheet (2004) reviewed the mortality figures from 12 comparable postconstruction monitoring studies and found that the fatality rate averaged 2.3 bird deaths per turbine per year and 3.1 birds per megawatt per year of capacity in the United States (outside California). Fatality rates have ranged from a low of 0.63 per turbine and 1 per megawatt at an agricultural site in Oregon to 10 per turbine and 15 per megawatt at a fragmented mountain forest site in Tennessee (NWCC 2004). This information, which is shown in Table 5-2, will be updated in 2008 to incorporate newly available data.

Table 5-2. Estimated avian fatalities per megawatt per year

Wind Project and Location	Total Fatalities
Stateline, OR/WA	2.92
Vansycle, OR	0.95
Combine Hills, OR	2.56
Klondike, OR	0.95
Nine Canyon, WA	2.76
Foote Creek Rim, WY (Phase 1)	2.50
Foote Creek Rim, WY (Phase 2)	1.99
Wisconsin	1.97
Buffalo Ridge, MN (Phase 1)	3.27
Buffalo Ridge, MN (Phase 2)	3.03
Buffalo Ridge, MN (Phase 3)	5.93
Top of Iowa	1.44
Buffalo Mountain, TN	11.67
Mountaineer, WV	2.69

Source: Data adapted from Strickland and Johnson (2006)

- Before 2003, bat kills at wind farms studied were also generally low. The frequency of bat deaths in 2003 at a newly constructed wind farm in West Virginia, though, led researchers to estimate that 1,700 to 2,900 bats had been killed, and that additional bats had probably died a few weeks before and after the six-week research period (Arnett et al. 2005). According to a USGS biologist, bat mortality has also been higher than expected at a number of sites in the United States and Canada (Cryan 2006).

Wildlife collisions with wind turbines are a significant concern, particularly if they affect species populations. To date, no site or cumulative impacts on bird or bat populations have been documented in the United States or Europe. But that does not mean that impacts are nonexistent. This is a particular worry with bats because they are relatively long-lived mammals with low reproduction rates, according to a peer-reviewed study (Arnett et al. 2005). BWEC is currently conducting the necessary research to understand the risks to bats.

Concerns about uncertain risks to birds and bats can lead permitting agencies and developers to conduct lengthy and costly studies that may or may not answer the wildlife impact questions raised. More research is necessary to more clearly understand the link between preconstruction surveys and postconstruction monitoring results. Well-designed research programs can, however, be costly for many projects and require care in assessing the appropriate levels of analysis.

Addressing these uncertainties through additional, focused research would be necessary if the United States is to increase wind development. Although many factors influence decisions to build wind projects, wildlife and environmental concerns can cause site exclusion because of the following:

- Concerns about potential wildlife impacts
- Costly study requirements
- Future risk mitigation requirements
- Conflicts with other resources

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The long term viability of the wind industry will be helped by acknowledging and addressing the challenges raised by these uncertain risks. Collaborative efforts such as BWEC and GS3C offer constructive models for this undertaking.

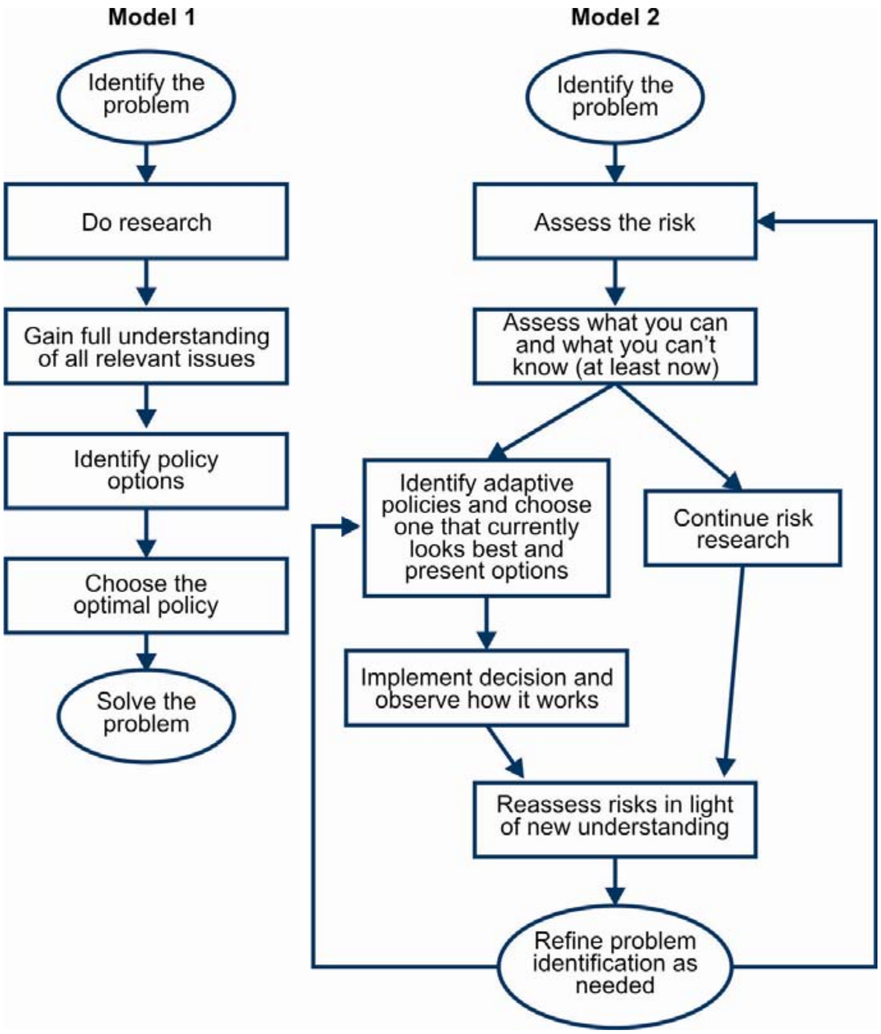
5.3.3 MANAGING ENVIRONMENTAL RISK AND ADAPTIVE MANAGEMENT PRINCIPLES

Dealing with uncertainties associated with siting wind power facilities is a challenge for some institutions because it requires a management structure with high levels of social trust and credibility. As a result, various stakeholders are investigating how adaptive management principles might be applied to assess and manage wildlife and habitat risks at wind power sites. Under these models, developers and operators of the wind site, along with permitting agencies, could adjust the management of the site and the level of required monitoring studies to the potential challenges that arise over the life of the project.

Although the term is used often, "adaptive management" is not always well defined. Here adaptive management refers to an evolutionary management approach that purposely seeks to adapt management and decision-making processes to evolving knowledge of the technology or environmental risks in question (Holling 1978; Walters 1986; Lee 1993). "Social learning" is a centerpiece in this approach, with management seeking to enhance its capability to learn from experience and from an expanding body of knowledge. Management solutions are regarded more as experiments than as definitive solutions to the challenges involved. Valuable experience with this approach exists in such areas as watershed planning (Lee 1993; NRC 2004), fisheries (Walters 1986), and forestry (Holling 1978).

An adaptive management approach contrasts with the more typical regulatory approaches, which assume that sufficient knowledge exists at the outset to define environmental risks and effects. The basic differences between two decision-making approaches—a linear approach commonly called "command and control," and the adaptive management approach—are quite apparent in Figure 5-3. In the figure,

Figure 5-3. Linear decision strategy (command and control) and interactive model with adaptive management principles



Source: Morgan et al. (2007)

Model 1 assumes that sufficient research and assessment can be done before the technology or management system is deployed, allowing an appropriate management system and the needed regulatory requirements to be put in place at the outset. Risk analysis plays a critical role in this process, with the assumption that major risks can be identified and assessed and appropriate mitigation systems instituted. In Model 2, the assumptions address different types of situations—the risks are uncertain and unlikely to be resolved in the near future; the risks can only be partially assessed at the outset; and surprises are likely as experience unfolds. This model emphasizes the importance of flexible, rapid response to new knowledge or events.

Accordingly, this risk management approach might well be suited for a technology such as wind energy, where experience and knowledge are still growing and where documented effects are strongly site-specific. Guiding principles and applications for this approach are still evolving, but adaptive management seems particularly well suited for situations of high uncertainties or conflict in the political process.

5.4 PUBLIC PERCEPTION AND ENGAGEMENT

Because the environmental benefits of wind energy are significant, public support for expanding wind energy development is widespread. The impacts of wind projects, however, are predominately local and can concern some individuals in the affected communities and landscapes. A primary challenge in achieving 20% of U.S. electricity from wind is to maximize the overall benefits of this form of energy without disrupting or alienating specific communities, especially prospective communities that do not have experience with wind turbines.

5.4.1 PUBLIC ATTITUDES

Wind energy development receives considerable general support among the U.S. population. Of those polled in a study conducted by Yale University in 2005, more than 87% want expanded wind energy development (Global Strategy Group 2005). Only a minority of the U.S. population appears to oppose wind energy, but that opposition can strengthen when particular sites are proposed. Some evidence indicates that, over time, opposition might decrease and support might grow. Surveys commissioned in the United Kingdom and Spain have found, for example, that local support for a wind project increased once it was installed and operating.

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Selected Public Opinion Surveys

- In April 2002, RBA Research conducted a study for the British Wind Energy Association of people living near a small project in the United Kingdom. It found that 74% of participants supported the wind farm—37% strongly—and only 8% were opposed. Of those opposed to the project, about 25% remained opposed after the project was constructed. Sixty percent later supported the wind farm (RBA Research 2002).
- Although polls show broad statewide support for the Cape Wind offshore project in Massachusetts, some opponents have been very vocal. When asked, however, some opponents say they might support the project if it were part of a broader strategy to combat global climate change. More information on this topic can be found at www.mms.gov/offshore/alternativeenergy.

Communities must be consulted about the global impacts of wind, and this must include addressing their concerns early on. Involving affected communities early is critical to identifying concerns and addressing them proactively. Stakeholder concerns must be taken seriously, and a long-term commitment to understanding stakeholder interactions must be made.

5.4.2 VISUAL IMPACTS

Wind turbines can be highly visible because of their height and locations (e.g., ridgelines and open plains). Reactions to wind turbines are subjective and varied. The best areas for siting wind turbines tend to be those with lower population densities. Although this can minimize the number of people affected, less populated areas may also be prized for tranquility, open space, and expansive vistas. Some people feel that turbines are intrusive; others see them as elegant and interesting. In either case, the visual impacts of wind energy projects may well be a factor in gauging site acceptability.

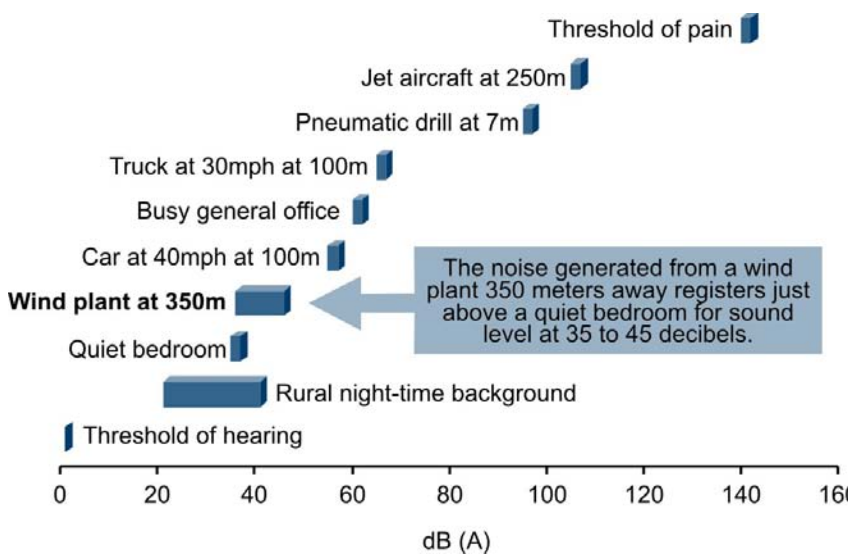
Discourse with communities about the expected impacts is important. Wind project developers can conduct visual simulations from specific vantage points and produce maps of theoretical visibility across an affected community (Pasqualetti 2005). With this information, a developer can make technical adjustments to the project layout to accommodate specific concerns, relocate wind turbines, reduce the tower height, or even propose screening devices (such as trees) to minimize visual impact. All of these steps can, of course, affect the economic feasibility of a proposed project, so they should be weighed carefully in siting and development decisions.

Because almost all commercial-scale wind turbines rise more than 60 m above the ground, proposed wind projects must be reviewed by the Federal Aviation Administration (FAA). In February 2007, the FAA updated an advisory circular (FAA 2007) dealing with obstruction lighting and marking, including new uniform recommendations for lighting wind energy projects. The new FAA suggestions are designed to allow pilots flying too low to be warned of obstructions and minimize intrusion to neighbors. The guidance recommends that wind energy projects should be lit at night, but now the lights can be up to 0.8 km apart and be placed only around the project perimeter, reducing the number of lights needed overall. The guidelines recommend red lights, which are less annoying than white lights to people nearby. No daytime lighting is necessary if the turbines and blades are painted white or off-white.

5.4.3 SOUND

All machinery with moving parts make some sound, and wind turbines are no exception, though advances in engineering and insulation ensure that modern turbines are relatively quiet; concerns about sound are primarily associated with older technology, such as the turbines of the 1980s, which were considerably louder. The primary sound is aerodynamic noise from the blades moving through the air—the "whoosh-whoosh" sound heard as the blades pass the tower. Less commonly heard in modern turbines are the mechanical sounds from the generator, yaw drive, and gearbox. When the wind picks up and the wind turbines begin to operate, the sound from a turbine (when standing at or closer than 350 m) is 35 to 45 decibels (dB; see Figure 5-4). This sound is equivalent to a running kitchen refrigerator.

Figure 5-4. Decibel levels of various situations



Source: BWEA (2007)

When proposing a wind energy project, wind developers can conduct studies to predict sound levels in various places, including in nearby buildings or homes. Turbines noise might be more obtrusive if, for example, they are located on a windy ridge or if houses are located downwind in a sheltered valley. Changes can usually be made to a project if the sound levels at a particular location are deemed too high. In general, standard setbacks from residences and other buildings appear to reasonably ensure that sound levels from a wind project will be low and nonintrusive.

5.4.4 Land Value

The primary asset for many families is their home, so property values are a serious concern. Residents can become particularly concerned about possible declines in local property values when wind energy projects are proposed in their community. To ascertain what effects they are likely to experience, they may look to other communities with existing wind facilities.

Studies of the effects of wind projects on local property values should be done with great care, even though extensive studies have already been conducted on other energy facilities, such as nuclear plants. Because home values are a composite of many factors, isolating the effects of proximity to a wind project is important (though only a part of the full picture). Wind projects also tend to be located in areas of low residential density, which further compounds the difficulties of controlling the impact on property value. To date, two studies (see “Wind Energy and Home Values” sidebar) have examined these issues in the United States. Though neither is definitive and additional work in this area is needed, both studies found little evidence to support the claim that home values are negatively affected by the presence of wind power generation facilities.

Individuals with turbines on their properties might actually see an increase in their property values because of the lease payments paid by the wind project owner. Lease payments tend to be $2,000 to $5,000 (US$2006) per turbine per year, either through fixed payments or as a small share of the revenue.

Wind Energy and Home Values

In 2003, the Renewable Energy Policy Project (REPP) conducted a study of 24,000 home sales surrounding 11 wind projects in the United States. It compared the average selling price over time of homes near the wind project with a nearby control area that was at least 8 km from the project. No clear evidence of adverse effects on property values was found. In some communities, home values near the facilities rose faster than properties in the control group (Sterzinger, Fredric, and Kostiuk 2003).

In April 2006 a Bard College study focused on a 20-turbine wind project in Madison County, New York. Researchers visited each home, measured the distance to the nearest turbine, and ascertained to what degree the home could see the wind facility. This study also concluded that there was no evidence that the facility affected home values in a measurable way, even when concentrating on homes that sold near to the facility or those with a prominent view of the turbines (Hoen 2006).

5.5 Siting/Regulatory Framework

Currently, wind energy projects are governed by a complex set of laws. Projects are subject to the input of a diverse set of decision makers and different permitting regulations apply in different parts of the country. Authorities at local, state, and federal levels make siting decisions. These authorities have different responsibilities relative to a project, and there can be inconsistencies among them and even within the same agency. In some places, primary decisions rest with the local jurisdiction, although federal and state requirements may still apply. A wide diversity of requirements means that projects across the country must adhere to different standards, and different information is often required before permits are issued. Differing levels of public involvement also occur in these processes. A dramatic increase in development is likely to make this situation even more complex for developers and decision makers alike. Increased uniformity of regulatory requirements across regions would greatly facilitate the increased deployment of wind projects necessary to reach the 20% Wind Scenario.

5.5.1 Local

Locally-elected officials make siting decisions at the county level. This allows the community to maintain control of local land use decisions, which is especially attractive in states where local authority is highly prized. Responsibilities differ among local bodies, but local commissions are often responsible for property assessments, rural road maintenance, economic development, zoning, and water quality (NACO 2003). Local commissions typically are concerned with protecting the environment, enhancing tax revenue, and preserving the local quality of life.

In some cases, local authorities may feel ill-equipped to weigh the highly technical information presented by a wind project developer. They can be easily influenced by proponents or opponents armed with incomplete or inaccurate information. In communities where wind development has a history, decision makers are more comfortable rendering considered permit decisions.

Most wind energy projects go through the local conditional use permit process and must spell out the conditions under which a project will operate. For example, a project permit might limit the sound level or require a setback distance from roads, houses, or property lines. Counties can also create ordinances to permit wind energy facilities: In Pike County, Illinois, the County Board created a permitted use ordinance that lays out standard conditions for wind projects; decision makers in Klickitat County, Washington, designated specific areas to encourage and guide wind energy development; and the local authorities in Kern County, California, conducted a county-wide environmental impact review to enable development of the Tehachapi Wind Resource Area.

5.5.2 State and Federal

States can control siting decisions either through specific decision-making bodies or by virtue of rules set for projects on state-controlled land. In addition, a state agency—such as a wildlife agency—might establish guidelines for siting wind projects. State guidelines can require maintaining certain sound levels or conducting environmental studies.

A few states have an energy siting board, which places the authority to review energy facilities with the state utility commission (i.e., a public service commission). The governor or legislature usually appoints representatives, and because they are more accountable to the public, they tend to be generally more familiar with this sector. The charge of these state commissions or boards often includes supplying reliable electric service at reasonable prices. Concerned individuals or project opponents have legal recourse to raise objections by formally challenging a commission decision.

The federal government participates in regulating wind energy projects through several different agencies, depending on the circumstances. Unless there is federal involvement, such as when developers propose a project on federally-managed land or there is a potential effect on areas of federal oversight, wind energy projects are not usually subject to the National Environmental Policy Act (NEPA). An agency can trigger the provisions of NEPA by undertaking a major federal action, such as allowing construction of a large energy project on or adjacent to federal lands (NEPA 1969).

The federal agencies that follow have mandates that may be related to wind energy:

- The **Federal Aviation Administration (FAA)** conducts aeronautical studies on all structures taller than 60 m for potential conflicts with navigable airspace and military radar, and ensures proper marking and lighting. Developers are required to submit an application for each individual turbine. From 2004 to 2006, the FAA approved almost 18,000 wind turbine proposals, nearly half in 2006 alone, and issued only eight determinations of hazard (Swancy 2006).
- The **Bureau of Land Management (BLM)** manages 105 million hectares of public land, mostly in the western United States. In 2005, the BLM finalized a programmatic environmental impact statement for wind energy development on BLM lands in the West. This statement includes best management practices for wind energy projects, sets standard requirements for projects, and allows for site-specific studies. As an alternative, wind developers can rely on the previous programmatic NEPA document and provide a development plan without having to do a full environmental impact statement (EIS) at each site, which can save valuable resources and time.
- The **U.S. Army Corps of Engineers (USACE)** issues permits for any development that will affect wetlands. Roads, project infrastructure, and foundations at some wind project sites have the potential to affect wetlands. Projects must also comply with the Endangered Species Act if any threatened or endangered species will be adversely affected.
- **The U.S. Fish & Wildlife Service (USFWS)** can pursue prosecution for violations of the Migratory Bird Treaty Act, which prohibits the killing or harming of almost all migratory birds. Some migratory birds, however, can be taken under a permit or license. The USFWS also enforces the Bald and Golden Eagle Protection Act, which gives additional protection to eagles. The USFWS exercises prosecutorial discretion under these statutes. To date, no wind energy companies have faced action under either law, but flagrant violations without mitigation could be subject to prosecution.
- The **Minerals Management Service (MMS)** oversees permitting for offshore ocean-based wind energy projects proposed for the outer continental shelf (OCS). MMS is developing the rules and issued a programmatic environmental impact statement for all alternative energy development on the OCS. New regulations are expected in 2008.
- The **U.S. Department of Agriculture Forest Service (USFS)** manages 78 million hectares of public land in national forests and grasslands. Projects sited on any Forest Service lands are subject to NEPA, and potentially to siting guidelines that the Forest Service is currently developing.

- The **U.S. Department of Defense (DOD)** has no formal review process for wind energy projects, although DOD does participate in the FAA studies. Wind energy companies planning a project near an Air Force base, however, generally work with base leadership to address and avoid conflicts.
- The **U.S. Department of Energy (DOE)** has taken the lead in creating an interagency project siting team. The team reviews how wind sites affect government assets such as radar installations, and decides how to plan for and mitigate those impacts.

5.6 Addressing Environmental and Siting Challenges

In order to install more than 10 GW of wind capacity per year by 2014, the United States will need to have a consistent way to review and approve projects. Examples below reflect what mature energy industries are doing to address concerns about wildlife and energy facility siting issues. The approaches described outline steps that could be adopted for a 20% Wind Scenario. The wind energy industry—in partnership with the government and nongovernmental organizations (NGOs)—will need to address environmental and siting issues.

5.6.1 Expand Public-Private Partnerships

States, collaboratives, and the National Academy of Sciences (NAS) have identified gaps in the knowledge base about wind energy and its risks. This situation is not surprising for a relatively new energy technology. The knowledge gaps are framed in questions such as:

- How can large deployments of wind energy generation contribute to national climate change goals and significantly reduce GHG emissions?
- Can bats be deterred from turbines?
- How high do night-migrating songbirds fly over ridgelines?

Sometimes developers address these questions at specific sites, but broader research is urgently needed on a few of the most significant questions.

Several research collaboratives have been formed (see sidebar entitled "Examples of Existing Wind Energy Research Collaboratives") to ensure that the interests of various stakeholders are represented, that research questions are relevant, and that research results are widely disseminated. Collaboratives can help to avoid relying on industry-driven research, which critics often perceive as biased. Various combinations of technical experts and informed representatives from industry, relevant NGOs, and government agencies currently participate in ongoing collaboratives on wind energy. For example, BWEC is exploring the effectiveness of an acoustic deterrent device to warn bats away from the spinning blades of wind turbines. Although the risk to bats might be greater at some sites than at others, it is not necessarily feasible or appropriate for one company or one project to foot the entire bill for this research. A public–private partnership is often a more effective way to undertake and fund the research needed, and might also lead to more credible results.

5

Examples of Existing Wind Energy Research Collaboratives

Bats and Wind Energy Cooperative (BWEC)

After learning in 2003 that thousands of bats had been killed at a West Virginia site, the wind energy industry collaborated with Bat Conservation International, the USFWS, and the National Renewable Energy Laboratory (NREL) to form BWEC. This organization has developed a research program to explore ways to reduce fatalities. Its work currently centers on two areas: (1) understanding and quantifying what makes a site more risky for bats and (2) field-testing deterrent devices to warn bats away from wind turbine blades.

National Wind Coordinating Collaborative (NWCC)

NWCC is a forum for defining, discussing, and addressing wind–avian interaction issues, with a focus on public policy questions. Supported by funds from DOE, the NWCC Wildlife Workgroup (WWG) serves as an advisory group for national research on wind–avian issues. The group released a report, *Studying Wind Energy/Bird Interactions: A Guidance Document*, which is the first-ever comprehensive guide to metrics and methods for determining and monitoring potential impacts on birds at existing and proposed wind energy sites. Additionally, the WWG has facilitated six national research meetings. It is subdivided into a number of groups focused on specific tasks, such as development of a “mitigation toolbox.”

Grassland/Shrub-Steppe Species Collaborative (GS3C)

The GS3C is a voluntary cooperative to identify what impacts, if any, wind energy has on grassland and shrub steppe avian species. Established in 2005 as the Grassland/Shrub Steppe Species Subgroup, the GS3C includes representatives from state and federal agencies, academic institutions, NGOs, and the wind industry.

As development levels ramp up, an overarching research consortium that would combine the work of these collaboratives could focus on addressing potential risks and ensuring that the most critical uncertainties are research priorities. As the more focused groups come together in a region, they could examine some of the habitat and biological sensitivity issues to understand which areas are most appropriate for development. With the public–private nature of the consortium, the conversation might shift from where development is inappropriate to where it is most promising. These groups, or a larger institute, could also identify priority conservation areas and work toward enhancing key habitat areas.

If the wind energy sector is to increase installations to more than 16 GW of capacity per year after 2018, research consortia could be created to take part in sustainable growth planning. A region, for example, might decide to open to development because new transmission lines are planned. In this case, a collaborative research body could determine what baseline wildlife and habitat studies are needed; organize and fund researchers to begin the work; and determine what mitigation, habitat conservation, or other activities might be appropriate for the area.

5.6.2 Expand Outreach and Education

Public acceptance of wind projects may increase if the local community directly shares in the benefits from a new wind energy development. In Europe, for example, tax law allows individuals to invest directly in wind projects. Those individuals might well view their turbines as a source of income and feel more positive about the siting of turbines nearby.

In the United States, examples of direct community impacts include:

- **Community wind:** Groups of individuals join together to develop and own a project. Although this can be risky because of the significant complexity and capital required to successfully build a wind project, the rewards are significant. A town or municipality sometimes purchases a turbine to generate power and lower public electricity bills. These groups might develop a smaller project in conjunction with a commercial development to leverage the economies of scale available for turbine purchases, construction, and operations and maintenance.
- **Property tax payments:** Wind projects are multimillion-dollar facilities that can make a significant contribution to a community's tax base. Projects are usually on leased private property, with the project owner paying any related property taxes.
- **Payment in lieu of taxes:** In places where property taxes are not required, project owners often contribute to a local community fund in lieu of taxes.

In other energy facility siting programs, communities might protect property values. Desired facilities are also sometimes collocated in the community as a form of incentive. Many such options exist and any combination might be part of a siting strategy. Wind energy developers can engage residents in a prospective host community to explain potential impacts, share information about the project, and learn about community concerns. This early involvement gives citizens an opportunity to ask questions and have their concerns addressed.

5.6.3 Coordinate Land-Use Planning

Successfully addressing numerous inconsistencies in permitting and regulation will require government and industry stakeholders to review the policies and procedures currently being implemented across multiple jurisdictions. In the long term, it may be necessary to create a sustainable growth planning effort as new areas of development open. A number of NGOs already have ecoregional plans that may yield a solid baseline of biological data. In 2006, states also completed wildlife action plans that identify high-priority actions needed to preserve and enhance their wildlife resources.

Numerous states and federal agencies have developed, or are in the process of developing, siting guidelines for wind power developments. Some states have created siting guidelines in conjunction with implementation of their state renewable portfolio standards (RPS). Other collaborative efforts to develop guidelines are moving forward through wildlife or energy agencies. Development of siting guidelines gives developers and agency officials a clear pathway to what may be required in certain jurisdictions, although time and cost considerations are involved.

5.7 PROSPECTS FOR OFFSHORE WIND ENERGY PROJECTS IN THE UNITED STATES AND INSIGHTS FROM EUROPE

Europe's experience with offshore wind energy projects is instructive for how the United States might address environmental and siting challenges. European developments are supported by ambitious national goals for wind deployment, financial instruments and subsidies, and commitments to reduce GHGs. Direct comparisons and lessons learned would be instructive but need to be applied with appropriate cautions about different public policies.

Offshore Wind Plant Siting and Seabed Rights in the United States

Various U.S. government agencies are responsible for evaluating and approving the siting, installation, and operation of wind power plants in the ocean. Until recently, offshore siting was notably more complex than land-based siting because of unclear and overlapping legal and jurisdictional authorities.

Before the passage of the Energy Policy Act (EPAct) of 2005, the USACE assumed permitting authority over proposed offshore wind energy developments. With EPAct 2005, Congress delegated authority to grant easements, leases, or rights-of-way in coastal waters to the MMS under the DOI.

Uncertainty about the extent of potential impacts of offshore wind projects—in addition to the lack of well-designed siting strategies— and the lack of long-term scientific information to fully evaluate the technology can contribute to delays in deployment (Musial and Ram, 2007).

A growing awareness of the large potential for electricity contributions from offshore wind energy has led to numerous proposals for siting offshore wind plants in European seas. Currently, 26 projects are installed in the North and the Baltic Seas in eight nations with a combined capacity of more than 1200 MW. A major scientific effort is in progress to support these projects. More than 280 research studies and assessments are examining environmental and human effects from installed offshore wind installations (SenterNovem 2005). Studies have also been conducted on birds, marine ecology, and animal physiology (Gerdes et al. 2005). Others have addressed the planning, construction, operations, maintenance, and decommissioning of turbines.

By contrast, the United States does not yet have any commercial-scale offshore wind power sites, and proposals for developing them are still limited. Preliminary environmental analyses relating to offshore installations are restricted to NEPA-related requirements for specific projects in federal waters. (Table 5-3 lists proposed projects and the documentation relating to the permitting and NEPA process.)

The state of knowledge and assessment of risks surrounding offshore wind energy are still emerging, which is characteristic of the early stages of any energy technology. To date, Denmark has conducted the most extensive before-after-control-impact study in the world. The most recent environmental monitoring program from this study, spanning more than five years, concluded that none of the potential ecological risks appear to have long-term or large-scale impacts (DEA 2006). Denmark intends to do further research, however, to assess the effects over time of multiple projects within the same region.

Table 5-3. Status of offshore wind energy applications in state and federal waters

Type of Initiative[a]	Developer	Project Location	Number of Turbines Proposed	Federal Application Filed	Status as of June 2007
Project	Cape Wind Associates	Nantucket Sound	130	November 2001	Received permit approval for the met tower in 2002; USACE issued a draft EIS in November 2004; MMS issued a notice of intent (NOI) to prepare a new EIS in May 2006. Massachusetts issued a final environmental impact report (FEIR); draft environmental impact statement (DEIS) in progress by MMS.
Project	Long Island Power Authority and Florida Power & Light	Long Island Sound	40	July 2005	Joint application submitted to USACE April 2005; MMS issued an NOI to prepare an EIS in June 2006; project cancelled in October 2007.
Project	Wind Energy Systems Technologies	Galveston, TX	50–60	N/A (Texas state waters)	Signed lease with Texas General Land Office in 2005. Meteorological tower installed to begin collecting data in 2007.
Project	Bluewater Wind LLC	Delaware	70	TBD	Won competition May 22, 2007, with Delmarva Power & Light
Project	Hull Municipal	Boston Harbor	4	N/A (Massachusetts state waters)	Collecting data. Received funding from Massachusetts Technology Collaborative to support permitting and siting analyses.
Announced	Patriot Renewables LLC	Buzzards Bay, MA	90–120	N/A (Massachusetts state waters)	Applied for state approval with Massachusetts Environmental Affairs, May 2006. Conducting feasibility studies.
Announced	Southern Company	Off the coast of Savannah, GA	3–5	No current plans	Two-year collaborative study with Georgia Institute of Technology (Georgia Tech) concluded that conditions are favorable but current cost and regulatory situation precludes development.

[a] In this table, a "Project" is a planned commercial development or demonstration where complete state or federal applications have been submitted to appropriate permitting agencies. "Announced" refers to proposals at the feasibility study and data collection stage, with no commercial plans as yet and no permit applications completed.

To date, members of the European wind industry and other stakeholders have largely mitigated risks related to wind energy or decided that the local siting risks are less of a concern than other factors, such as air emissions and the larger global risks of climate change. Precautionary principles apply during the adoption of facility siting and design, as well as risk management principles. Because risks are highly site-specific, well-planned siting strategies are critical to future offshore wind developments. Successful strategies in Europe have recognized the need to engage local populations in siting decisions and development planning. This builds community support for wind facilities by addressing local and site-specific concerns, including:

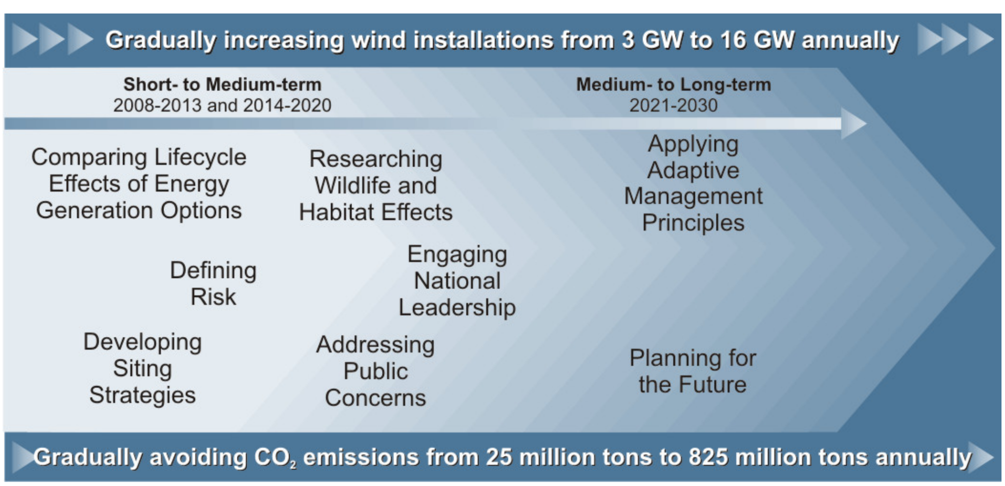
- Fish and benthic communities
- Undersea sound and marine mammals
- Electromagnetic fields and fish behaviors
- Human intrusion on seascape environments
- Competing commercial and recreational uses of the ocean
- Other socioeconomic effects, including tourism and property values.

As the United States establishes a regulatory process and siting strategies for offshore wind projects, much can be learned from Europe's decades of experience with offshore wind. If the United States supports a major increase of offshore wind deployments over the next two decades, it will need to develop an ambitious and well-managed environmental research and siting program and lay the groundwork for collaborative approaches that engage the public and interested stakeholders.

5.8 FINDINGS AND CONCLUSIONS

To scale up wind energy development responsibly, benefits and risks should be considered in context with other energy options. Remaining uncertainties associated with overall risks, cost-effective opportunities for risk mitigation, strategic siting approaches, enlarged community involvement, and more effective planning and permitting regimes can also be considered. Figure 5-5 outlines activities that may be needed over the near and longer terms. Some of the activities would begin now and continue through 2030; more details are given in the subsections that follow. Given the significant ramp-up of wind installations by 2018 in the 20% Wind Scenario, these actions would need to occur within the next decade, in time to anticipate and plan for siting strategies and potential environmental effects.

Figure 5-5. Actions to support 20% wind energy by 2030



Near- and Mid-Term Actions

Comparing lifecycle effects of energy generation options: The knowledge base for comparing wind energy with other energy options—according to their climate change implications—is still uneven and incomplete. Such knowledge could prove helpful to wind energy developers; electric utilities; and national, state, and local regulators in evaluating wind energy developments. In fact, EPAct 2005 included authorization language for an NAS study of the comparative risk and benefits of current and prospective electricity supply options; the study has not begun.

Researching wildlife and habitat effects: The current research program on wind energy is largely driven by the problems that have arisen at specific sites, such as bird mortality in California and bat mortality in West Virginia. Additional research on wildlife and habitat fragmentation, which takes a collaborative approach and involves interested parties, affected communities, and subject matter experts, would be informative and should be placed within the context of other energy risks.

Defining risks: A systematic risk research program that addresses the full range of human, ecological, and socioeconomic effects from wind project siting is needed. Such a study would establish a systematic knowledge base to inform research priorities and decision makers. A comprehensive survey of risk issues that might arise at different sites has yet to be designed and undertaken, although several state agencies—such as the California Energy Commission—are developing these priorities. Along with these risk research programs, the associated cost and time implications must be demarcated.

Engaging national leadership: Evolving national and state policies and corporate programs seek to minimize human-caused emissions of greenhouse gases. Wind energy is an important part of the portfolio of energy technologies that can contribute to this goal. Many positive impacts are projected from wind energy comprising a larger share of the U.S. electricity grid, but these data must be quantified and made publicly available. National leadership could facilitate rapid progress toward 20% wind energy.

Develop siting strategies: The risks associated with wind energy deployment are heavily site-specific, and public responses will vary among potential sites. Siting strategies are needed to identify sites that are highly favored for wind energy developments, but also to avoid potential ecological risks and minimize community conflict. The American Wind Energy Association (AWEA) is currently developing a siting handbook, which may be valuable as a first step in addressing this need. Further work could continue to enhance collaborative siting processes that engage states, NGOs, host community officials, and various other stakeholders.

Addressing public concerns: Building public support is essential if wind energy is to supply 20% of the nation's electricity by 2030. Although substantial national experience exists with siting different types of energy facilities, that experience has not yet been incorporated into wind siting strategies. The roots of public perceptions of and concerns about wind energy are not well understood.

Long-Term Actions

Applying adaptive management principles: As with other technologies, wind energy will continue to pose new uncertainties as existing ones are reduced. The knowledge base is certain to evolve as new sites are developed and the scale of wind development expands in the United States, in Europe, and in other parts of the world. Adaptive management concepts and approaches, which have been applied to the development of numerous other technologies, should also be considered for incorporation into wind energy development.

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Chapter 6. Wind Power Markets

Wind power suppliers and consumers span a broad range. Currently, wind power serves primarily large-scale utility markets, and smaller scale community-based projects are playing an increasing role in some regions. In addition, the eastern and Gulf Coast states are considering offshore proposals.

If 20% wind energy by 2030 were to be reached, supply and demand markets would need to expand to deliver wind energy to end-use customers throughout the United States. This chapter presents a brief overview of U.S. electricity markets, major wind power supply chain segments, market drivers, and their potential impacts on U.S. wind power expansion.

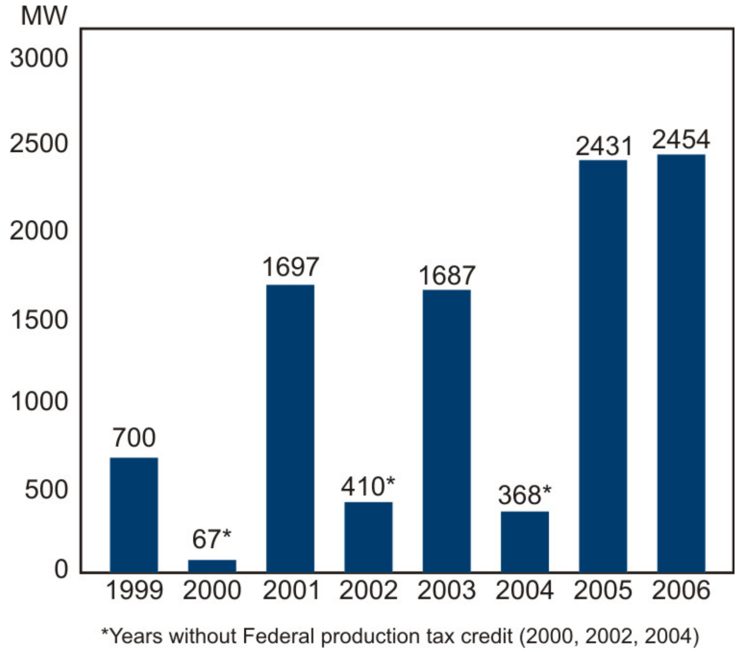
6.1 U.S. Market Evolution Background

The U.S. Department of Energy (DOE) projects U.S. electricity demand to increase by 39% from 2005 to 2030 (EIA 2007). Taking into account projected plant retirements and the implementation of energy efficiency and demand reduction programs, meeting this increased demand could require new electricity generation to increase by more than 50% over that period. Wind power is a viable option for meeting a substantial portion of this growing demand for electricity.

During the past seven years, the total number of wind installations worldwide has grown at an average annual rate of 27%. Recent growth of the wind power market in the United States has been driven by a dramatic reduction in the cost of wind energy, public interest in renewable energy, state renewable energy standards, federal production tax credits (PTCs), and volatile natural gas prices. Historically, however, periodic expiration and subsequent extensions of federal PTCs have resulted in intervals of no growth followed by explosive growth, as shown in Figure 6-1.

The U.S. wind power industry has experienced two major transformations in its history. In 1940, more than 100,000 wind turbines—many of them Jacobs Windmasters—were in operation across the Midwest, producing electricity for isolated farms and ranches. Their use declined, however, as electrification connected rural U.S. regions to electricity grids in the 1940s and 1950s. The oil price shocks of the 1970s stimulated new interest in renewable energy and led to the establishment of the Public Utility Regulatory Policies Act (PURPA) of 1978. By requiring utility companies to buy electricity from independent power producers (including wind companies), PURPA provided the foundation for the emergence of a second wind energy market in a few states in the 1980s. A key catalyst for wind's further development was California's investment tax credit and supportive state policies that jump started the bulk power wind industry in the early 1980s. The addition of federal tax credits also contributed to industry expansion. Several firms pioneered

Figure 6-1. U.S. wind energy capacity growth (shown in megawatts [MW]) slowed during years when the PTC expired



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modern wind turbine technology during this period, and by 1990 more than 6,000 turbines were operating in the state.

The significantly broader and larger wind electricity supply today originated in the late 1990s. This most recent expansion resulted from a technical revolution that is influencing electricity markets in dozens of countries around the globe. Public and private research and technological innovation have rapidly improved wind resource assessment and siting, wind turbine aerodynamics and component design, and power electronics. Turbine sizes have increased steadily, leading to improvements in wind generation economics. Wind plant reliability has also improved—today, manufacturers routinely guarantee the availability of their turbines at 97% or higher. Although the wind resource is variable, wind turbines are highly reliable and operate whenever winds are sufficient to generate electricity. The current U.S. wind energy market is robust and expanding at unexpected rates.

6.2 U.S. Electricity Market

Electricity in the United States is supplied mainly by the more than 3,000 utilities across the country, some of which are owned by shareholders, others by the customers they serve. State public utility commissions and the Federal Energy Regulatory Commission (FERC) oversee these utilities and specific electricity markets. Utilities and commissions work within a regulatory framework based on federal and state legislation and jurisdiction-specific regulations that vary throughout the country. As a result of these regulatory differences, the roles of utilities and commissions also differ, creating a variety of market structures at the local and regional levels. To bring wind energy to customers nationwide, wind project developers must accommodate these local and regional market features.

6.2.1 Electric Utilities

Approximately 200 investor-owned utilities (IOUs), 70 large municipal and federal or state systems, and 50 rural generation and transmission cooperatives supply power for more than 3,000 local distribution companies across the country. The largest of these utilities typically own power plants and generate much of the power they supply. They purchase the rest of the electricity needed to serve their customers from other utilities or from nonutility generators through power purchase agreements (PPAs).

Utilities serve a variety of customers with differing needs and priorities, both retail and wholesale. Retail customers are divided into three categories: residential, commercial, and industrial. Residential customers use energy in a single dwelling for personal service. Commercial customers often have multiple dwellings, offices, or business enterprises located in a multifunction building. Industrial customers are typically large manufacturing or assembly plants that have hundreds of workers and multiple electricity applications. Special forms of commercial and industrial customers include the federal, state, and local public sectors.

Retail electricity service to end-use customers is regulated by state commissions in many states and jurisdictions. Some states have implemented restructuring or deregulation of their electricity markets, increasing competition among electricity providers and retailers. In states where competitive entities are vying to supply electric generation and to serve retail customers, wind developers have the opportunity to build projects and deliver energy directly to customers. In states that have not restructured, wind developers can sell into wholesale markets or sell to the incumbent utilities under a PPA. Some utilities are pursuing options for owning and operating their own wind projects.

At the national level, FERC policies have been implemented to foster competitive wholesale electricity markets and spur innovation and efficiency improvements. FERC continues to review and modify, as appropriate, its policies concerning competition in wholesale power markets. FERC policies cover transmission lines, treated as a common carrier, meaning that it requires transmission providers to allow nondiscriminatory access to their wires. The large wholesale markets enable a more effective exchange of services and compensation for all electricity generators, including wind power generators, helping them compete for larger shares of generation markets.

To regulate their utilities, roughly half of states in the country have integrated resource planning (IRP) policies in place. An IRP policy requires utilities to evaluate opportunities to serve loads through energy efficiency and demand reduction programs on the same basis they use to plan new generation. In addition, utilities must compare supply alternatives—including fossil and non-fossil resources—on a risk-adjusted basis. Some decisions made under the IRP process consider local customer preference, which can influence decisions made by commissions in selecting generation options. As a result, the IRP process has been an important factor in establishing wind power markets.

6.2.2 Federal Agencies

In aggregate, the federal government is the largest single consumer of electricity in the world. Federal agency electricity consumption in 2005 was more than 55,000 gigawatt-hours (GWh), which would equate to approximately 18 gigawatts (GW) of wind capacity at a 35% capacity factor.

Federal agencies were encouraged to meet an executive order goal of 2.5% of site electricity from new renewable energy sources by the end of 2005. Agencies exceeded the goal with a final tally of about 3,800 GWh (6.9%) of electricity consumed coming from renewable sources (DOE 2006). There was a dramatic increase in 2004 and 2005, largely because of renewable energy certificate (REC) purchases by the Air Force, the General Services Administration, and the Environmental Protection Agency (EPA). Overall, 96% of federal renewable energy—outside the Department of Defense—was purchased with RECs.

The Energy Policy Act (EPAct) of 2005 also guides federal agency energy use. It requires the agencies to incorporate renewable energy into their electricity supply mix at an escalating rate beginning at 3.0% in 2007 and increasing up to 7.5% by 2013, to the extent economically feasible and technically practicable. Wind energy could play a significant role in meeting this goal, particularly through projects sited on federal lands, and both EPAct 2005 and the executive order goal will help advance wind power use across federal facilities.

6.2.3 POWER MARKETING ADMINISTRATIONS

Starting in the 1930s, the federal government created Power Marketing Administrations (PMAs) to market electricity generated by government-owned hydropower projects. The PMAs include the Bonneville Power Administration (BPA), the Western Area Power Administration (Western), the Southwestern Power Administration (SWPA), and the Southeastern Power Administration (SEPA). Though not technically a PMA, the Tennessee Valley Authority (TVA) has a similar purpose. Each of these entities operates as a utility, supplies power to other utilities, and often owns extensive transmission networks that are important to generators, including the wind industry. Western and BPA, in particular, have extensive transmission grids in regions with significant wind potential. Generally, the PMAs and the TVA are mandated by Congress to set rates at the lowest possible levels consistent with sound business principles. The PMAs provide access to available transmission capacity on their systems under FERC-approved transmission tariffs.

6.2.4 COMPLIANCE, VOLUNTARY, AND EMISSIONS MARKETS

Under a scenario of significant wind energy expansion, multiple revenue streams and diverse markets for wind generation output will be increasingly important. Compliance and voluntary markets, which have the potential to create separate and complementary revenue streams for supporting wind energy generation, can reduce risks. Emerging emissions reduction markets might also provide revenue streams.

Policy-Driven Markets

Compliance markets, or markets where there are standards for renewable energy contributions, play an important role in supporting the development of wind energy resources. Today, 25 states plus the District of Columbia have established renewable portfolio standards (RPS) requirements, which proscribe the amount of renewable energy that must be produced within the state. These compliance markets have been growing rapidly in recent years and hold the potential to substantially expand wind energy capacity. Current state RPS policies call for about 55 GW of new renewable energy capacity by 2020, and a number of states are considering increasing their targets.

Voluntary or Green Power Markets

Voluntary markets for renewable energy also play a key role in supporting new wind energy development. Today, more than 500,000 electricity customers across the nation are purchasing green power products through regulated utility companies, from green power marketers in a competitive market setting, or in the form of RECs.

These voluntary purchasers support about 2 GW of new renewable energy capacity, mostly wind. Sales have recently grown at annual rates exceeding 60%. Large nonresidential customers—including businesses; universities; and federal, state, and local governments—are driving much of the growth, and this trend is likely to continue.

Voluntary REC markets can also be important because they might be able to support wind energy projects in regions that have good wind regimes but no compliance markets (e.g., RPS). Because RECs are sold separately from commodity electricity, they can be used to support wind energy facilities in regions with the best resources. Some factors do limit the effectiveness of RECs, though, including the lack of a national REC tracking system, the lack of a national REC trading system, and the difficulty of using RECs in project financing.

Air Quality Markets

Throughout the past several decades, approaches for controlling pollution from fossil-based power generators have moved from traditional command and control strategies to market-oriented trading regimes that allow the most cost-effective emission reduction techniques to be applied first. Sulfur dioxide (SO_2) emissions were the first to be controlled with cap and trade programs, and now nitrogen oxides (NO_x) and mercury (Hg) programs have been added. Others, such as carbon dioxide (CO_2) programs, are currently under serious consideration. Markets must have accurate price information to operate efficiently, and these programs help to incorporate the external costs of pollutants from carbon-based fuels into power prices.

6.3 WIND POWER APPLICATIONS

There are four basic wind applications:

- Utility-scale wind power plants, both land-based and offshore
- Community-owned projects, which often produce power for local consumption and sell bulk power under contracts
- Institutional and business applications

- Off-grid home installations and behind-the-meter farm/ranch/home systems.

The size and number of turbines vary in each of these applications. Utility-scale wind power plants typically use turbines larger than 1,000 kW to produce large amounts of wholesale power, accounting for more than 90% of all wind power generated in the United States. A 1,000 kW turbine can supply electricity for about 300 homes. Off-grid and behind-the-meter projects usually employ turbines smaller than 100 kilowatts (kW).

Wind projects range from less than 400 watts (W) to more than 400 megawatts (MW), with much larger projects expected in the future. The utility-scale technology that started in California in the early 1980s revolved around 50- to 100 kW machines, while the standard size of today's more efficient and reliable turbines ranges from 1,500 kW to 2,500 kW.

6.3.1 Large-Scale Wind Power Plants

Wind power plants consist of a number of individual wind turbines that are generally operated through a common control center. The number can range from a few, to dozens, to hundreds of energy-producing turbines.

Wind projects that are 2,000 megawatts or larger have been proposed. Such large-scale wind projects will bring about new challenges and benefits, requiring (and large enough to justify) dedicated large-scale transmission infrastructure to carry power long distances on land or shorter distances offshore to urban demand centers.

Accelerated growth of wind power in the United States would almost certainly require developing a number of very large-scale projects, considering:

- **Siting constraints on traditional projects:** Installing large numbers of turbines in remote regions minimizes landowner objections to dense turbine siting in populated areas.
- **Geographic distribution of the wind resource:** Most high-quality land-based wind resources in the nation are in mountain and plains states. The 20% Wind Scenario would require significant amounts of these resources to be captured.
- **Development pace and scale of development:** A few very large projects can add as much wind generation capacity as hundreds of traditional 100 MW projects and can be developed and built much more quickly.
- **Restrictions on land-based deployment:** Some energy-constrained coastal areas will depend on offshore wind resources that will require large-scale project development to reduce overall infrastructure costs.

6.3.2 Offshore Wind

Coastal areas, especially in California and the northeastern United States, pay higher than average prices for electricity, so offshore wind developers have an added incentive—in the form of high market prices—to enter these markets. There are uncertainties with permitting requirements in federal waters. However, the Minerals Management Service (MMS) is in the process of developing proposed rules, along with a programmatic environmental impacts statement. The MMS program is expected to be in place toward the end of 2008. Still, technical, market and policy uncertainties are limiting the deployment of offshore wind turbines alone (see chapters 3 and 5 for more discussion of offshore wind).

In addition, the cost of offshore wind projects is higher than land-based turbines by about 40%, according to a study conducted by Black & Veatch, an engineering company based in Overland, Kansas (Black & Veatch, 2007). This higher cost can be attributed to the added complexity of siting wind turbines in a marine (and potentially harsher) environment, higher foundation and infrastructure costs, and higher operations and maintenance (O&M) costs because of accessibility issues and O&M associated with offshore locations and the marine environment.

In the next 10 years, the U.S. offshore wind market could play a more significant role in bringing new power generation online in selected regions of the country where electricity prices are higher than average, population density restricts power plant installations, shallow water sites are available, state governments have passed aggressive RPS requirements, and coastal communities support this energy option.

6.3.3 Community Wind

Community stakeholders have started to evaluate wind development as a way to diversify and revitalize rural economies. Schools, universities, farmers, Native American tribes, small businesses, rural electric cooperatives, municipal utilities, and religious centers have installed their own wind projects. Although community wind projects can be of any size, they are usually commercial in scale, with capacities greater than 500 kW, and are connected on either side of the meter. Community wind includes both on-site wind turbines used to offset customer's loads and wholesale wind generation sold to a third party.

Community wind is likely to advance wind power market growth because it has the following advantages:

- **Strengthens communities:** Locally-owned and -controlled wind development substantially broadens local tax bases and generates new income for farmers, landowners, and entire communities.
- **Galvanizes support:** Local ownership and increased local impacts broaden support for wind energy, engage rural and economic development interests, and build a larger constituency with a direct stake in the industry's success. Local investments and local impacts produce local advocates.

6.3.4 Small Wind

Small wind (sometimes called "distributed wind energy") refers to wind turbines that are generally smaller than 100 kW. Residences or businesses can install small wind turbines on-site to meet their local electricity demands, often selling excess electricity sold back to the grid on distribution lines. On-grid behind-the-meter applications, where turbines are connected to distribution lines and supply electricity to partially meet local loads, comprise the primary market for small wind. On-grid installations are currently supported by a variety of state and utility financial incentives, which reduce up-front capital costs to the consumer. Small wind can also include small units for off-grid applications, such as remote homes and livestock watering facilities as well as wind–diesel hybrid systems that are deployed in remote village settings, such as, Alaska.

Small wind has lower wind speed requirements, so more locations can accommodate and harvest wind. The U.S. small wind manufacturing industry dominates today's world markets, and deploying distributed wind energy in rural or remote parts of the United States can help to build acceptance of future wind power plants. As markets continue to expand and manufacturers increase their volume, the result will be lower cost turbines. An additional benefit, although small wind systems have higher per-kilowatt costs than utility-scale systems, they compete with retail instead of wholesale electricity rates, which are also higher.

Community Wind in Minnesota

Minnesota took major steps to encourage the development of renewables by requiring the state's largest utility, Xcel Energy, to acquire a growing amount of wind energy. The target was 425 MW in 1994, 825 MW by 1999, and 1,125 MW by 2003. This created a reliable wind energy market in the state which, in turn, helped wind energy find its way into many areas of Minnesota's economy, including construction, O&M, and engineering. It also forged the path for development of permitting rules that other states and counties use as models for writing their own regulations.

Community wind began in the United States in Minnesota in 1997, when local advocates worked with the legislature to create the Minnesota Renewable Energy Production Incentive (REPI). Local ownership was a priority for those who created this incentive, which paid $0.01 to $0.015/kWh for the first 10 years of production for projects smaller than 2 MW. In the beginning, local wind developers had to individually negotiate with utilities for interconnection and PPAs. It was not until a special community wind tariff—establishing a set power purchase rate of $0.033/kWh and standard procedures for interconnection for wind projects below 2 MW—was created in 2001 as part of Xcel Energy's merger settlement, that community wind projects really became feasible. The initial Minnesota REPI allocation was then quickly subscribed, and a second round was fully subscribed within 6 months. Pairing of these complementary policies allowed the community wind market to really take off.

Small wind energy market challenges include turbine availability (product gaps exist for 5-, 15-, and greater than 100 kW turbines); economics and lack of financial incentives across all market segments; turbine reliability; utility interconnections; and zoning and permitting.

6.3.5 Native American Wind Projects

Native American reservations constitute a special community with emerging interests in wind power development. Wind-generating potential on tribal lands, which is conservatively estimated at more than 1.5 GW, could make an important contribution toward the 20% Wind Scenario. At least 39 Native American reservations with significant wind power potential (Class 4 and higher) are located in remote areas that could support development. Self-governed Native American tribes also have a unique legal relationship with the U.S. federal government and are afforded increased opportunities under EPAct 2005.

6.4 Stakeholder Involvement and Public Engagement

As wind energy development proceeds in the United States, site selection and development will require well-designed and effective stakeholder engagement. The preceding sections outlined the markets and supply segments that can contribute to the 20% Wind Scenario. The types of stakeholders and their perceptions of wind energy are likely to vary markedly from one location to another. An important part of any stakeholder initiative is to identify the full range of interested parties and decision makers, such as public utility commissions and their staffers, utilities and regional transportation organizations and their customers, state and federal legislators, and financiers. Understanding stakeholder interests and how to effectively communicate with these various groups is central to the pursuit of 20% wind energy by 2030.

Experience with past wind and other energy facility development in the United States has brought home the critical importance of stakeholder involvement. The energy community now generally recognizes that effectively engaging stakeholders in siting-related decisions requires attention to a number of key factors:

- State and local siting guidelines and procedures are needed to establish a known and deliberate siting process in which local concerns and siting issues are fully considered. Developers must also be able to plan for and manage a predetermined and predictable process.
- The developer, state and local officials, and the host communities should collaborate on designing stakeholder outreach
- A comprehensive list of stakeholders—including those who will be targeted in the engagement efforts—should be compiled early in the process.
- Concerns and requirements of various stakeholders should be assessed. Needs should be identified and defined through interviews with stakeholders.
- The stakeholder-engagement process should begin before the site is assessed and selected so that baseline information can be established. Stakeholders should continue to be actively engaged throughout facility development and operation, with an emphasis on two-way communications.
- A neutral third party should carefully evaluate effectiveness of the engagement process along the way, to ensure that any initiatives incorporate new stakeholders that might appear and new concerns that might arise. This will also allow deficiencies in engagement and communications to be forthrightly addressed.

Finally, no element in an engagement and communications effort is more important than building trust among the developers, state and local officials, and members of the host community. Although this is a much more difficult task than is generally understood, experience has shown that openness, serious consideration of local concerns, and a participatory process all contribute substantially to successful outcomes.

6.5 CONCLUSIONS

Within the 20% Wind Scenario, multiple revenue streams and multiple markets for wind generation output would be increasingly important. Standards for renewable energy contributions as well as voluntary markets have the potential to create separate and complementary revenue streams for supporting wind energy generation while reducing risks. Today, 25 states have established RPS requirements. Compliance markets, which have been growing rapidly in recent years, can make substantial contributions to the expansion of wind energy capacity. Emerging emissions markets can also be a source of revenue streams.

To create the catalyst necessary to support aggressive wind energy growth, many different market drivers must converge; and if the significant increase in wind power development under the 20% Wind Scenario is to be realized, many stakeholders will need to embrace a robust wind future. Stakeholder interests are as diverse as stakeholder types; a long-term commitment to understanding and working with stakeholders will be critical for deploying significant levels of wind power. All segments of the market must be taken into account when planning for the wide adoption of wind-generated electricity. Market forces need to be targeted and utilized efficiently to leverage stakeholder interests if 20% of U.S. electricity from wind is to be realized.

6.6 References

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Appendix A. 20% Wind Scenario Impacts

A.1 Introduction

This appendix describes the analytic tool and assumptions that were used to identify some key components of the impacts, and technical challenges of providing 20% of the nation's electricity from wind in 2030. The 20% level was chosen exogenously as the central assumption of the evaluation. The relative cost difference between a scenario including 20% wind-generated electricity and a scenario in which no additional wind technology is installed after 2006 is the primary metric. All modeling assumptions contribute to this incremental cost of wind energy. Thus, changes to the assumptions increase or decrease the incremental cost of the 20% Wind Scenario over the scenario that does not include wind energy. No sensitivities exploring changes to the assumptions were performed for this analysis. Modeling assumptions are described in this appendix (See Table A-1) and Appendix B.

The National Renewable Energy Laboratory's (NREL) Wind Deployment System (WinDS) model was employed to simulate generation capacity expansion of the U.S. electricity sector through 2030. This model used a wind energy generation rate that would result in the production of 20% of projected electricity demand from wind by 2030. Carbon emission reductions in this 20% Wind Scenario have also been derived from the WinDS model outputs. Water savings associated with significant wind energy generation has been externally calculated as well. The assumptions used for these analyses were developed from a variety of sources and experiences that span the wind and electricity generation industries; model-specific details of these assumptions are presented in Appendix B.

The 20% Wind Scenario requires U.S. wind power capacity to grow from the current 16–17 gigawatts (GW) to more than 300 GW over the next 23 years. This ambitious growth could be reached in many different ways, with varying challenges, benefits, costs, and levels of success. This report examines one particular scenario for achieving this dramatic growth and contrasts it to another scenario called No New Wind, which assumes no wind growth after 2006 for analytic simplicity.

Considerations in the 20% Wind Scenario

- Wind resources of varying quality exist across the United States and offshore.
- Although land-based resources are less expensive to capture, they are sometimes far from demand centers.
- Typically, wind power must be integrated into the electric grid with other generation sources.
- Technology and power market innovations would make it easier to handle a variable energy resource such as wind.
- New transmission lines would be required to connect new wind power sources to demand centers.
- Transmission costs add to the cost of delivered wind energy costs, but today's U.S. grid requires significant upgrading and expansion under almost any scenario.
- Wind installations will require significant amounts of land, although actual tower footprints are relatively small.
- Domestic manufacturing capacity might not be sufficient to accommodate near-term rapid growth in U.S. wind generation capacity; the gap may be filled by other countries.

The authors recognize that U.S. wind capacity today is growing rapidly, although from a very small base, and that wind energy technology will be a part of any future electricity generation scenario for the United States. At the same time, there is still a great deal of uncertainty about what level of contribution wind could or is likely to make. In its *Annual Energy Outlook 2007 with Projections to 2030* (AEO), the Energy Information Administration (EIA) forecasts that an additional 7 GW—beyond the 2006 installed capacity of 11.6 GW—will be installed by 2030 (EIA 2007).[12] Other organizations are projecting higher capacity additions, and given today's uncertainties, developing a "most likely" forecast would be difficult. The analysis presented here sidesteps these uncertainties and contrasts the impacts of producing 20% of the nation's electricity from wind with No New Wind. This yields a parameterized estimate of some of the impacts associated with increased reliance on wind energy generation.

The analysis was also simplified by assuming that the contributions to U.S. electricity supplies from other renewable sources of energy would remain at 2006 levels in both scenarios. In addition, no sensitivity analyses have been done to identify how the results would differ if assumptions were changed.

Broadly stated, this 20% Wind Scenario is designed to optimize costs while recognizing certain constraints and considerations (see sidebar above). Specifically, the scenario describes the mix of wind resources that would have to be captured, the geographic distribution of the wind power installations, estimated land needs, and required utility and transmission infrastructure changes associated with 20% wind in 2030. It is not a definitive identification of the exact locations of wind turbines and transmission lines.

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The scenario reflects several assumptions about generation technology cost and performance as well as electric grid system operation and expansion. For example, wind technology development is projected to continue based on a history of performance improvements. The national transmission system is assumed to evolve in ways favorable to wind energy development by shifting toward large regional markets. In addition, future environmental study and permit requirements are not expected to add significant costs to wind technology.

The 20% Wind Scenario was constructed by specifying annual wind energy generation in each year from 2007 to 2030, based on a trajectory proposed in a previous NREL study (Laxson, Hand, and Blair 2006). The investigators forced the WinDS model to reach the 20% level for wind-generated electricity by 2030 and evaluated aggressive near-term growth rates. Next, they examined sustainable levels of wind capacity installations that would maintain electricity generation levels at 20% and accommodate the repowering of aging wind turbine equipment in wind installations beyond 2030. The 20% wind by 2030 trajectory from the NREL study was implemented in WinDS by calculating the percentage of annual energy production from wind, an increase of approximately 1% per year. Figure A-1 illustrates the energy generation trajectory proposed in the study, and the corresponding annual wind capacity installations that the WinDS model projects will meet these energy generation percentages.

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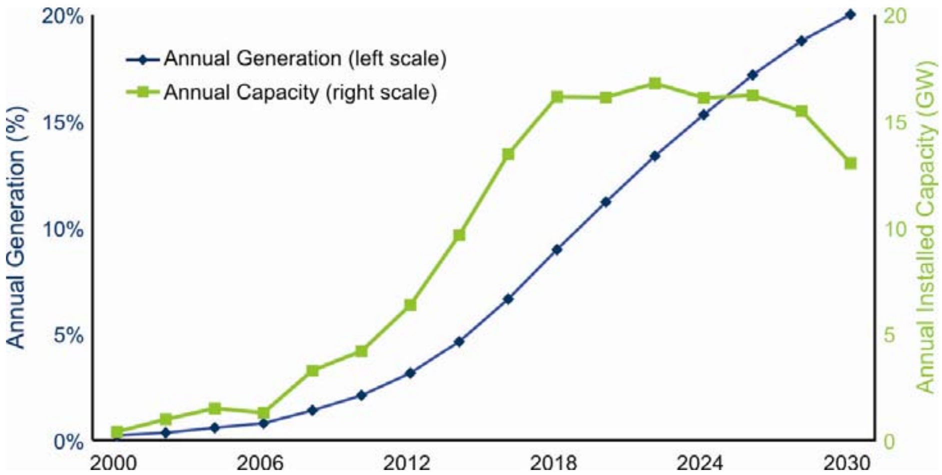
[12] AEO data from 2007 were used in this report. AEO released new data in March of 2008, which were not incorporated into this report. While the new EIA data could change specific numbers in the report, it would not change the overall message of the report.

Figure A-1. Prescribed annual wind technology generation as a percent of national electricity demand from Laxson, Hand, and Blair (2006) and corresponding annual wind capacity installation for 20% Wind Scenario from WinDS model



The combined cost, technology, and operational assumptions in the WinDS model show that reaching an annual installation rate of about 16 GW/year by 2018 could result in generation capacity capable of supplying 20% of the nation's electricity demand by 2030. This annual installation rate is affected by the quality of wind resources selected for development as well as future wind turbine performance. The declining annual installed capacity after 2024 is an artifact of the prescribed energy generation from the NREL study (Laxson, Hand, and Blair 2006), in which technology improvements and wind resource variations were not considered. The NREL study (Laxson, Hand, and Blair 2006) provides an upper level of about 20 GW/yr, because turbine performance is unchanged over time. Based on the wind resource data and the projected wind technology improvements presented in this report, sustaining a level of annual installations at approximately 16 GW/yr beyond 2030 would accommodate the repowering of aging wind turbine equipment and increased electricity demand, so that the nation's energy demand would continue to be met at the 20% wind level.

The 20% Wind Scenario does not include policy incentives such as a production tax credit (PTC) or carbon regulations, although such policies may make this growth trajectory more likely. It is implicitly assumed that a stable policy environment that recognizes wind's impacts could lead to growth rates that would result in the 20% Wind Scenario.

Some of the consequences of a 20% Wind Scenario in 2030, including carbon emission reductions and natural gas demand reduction, were calculated based on the results of the WinDS model. To estimate the impacts associated with incorporating electricity from wind into the grid at this level, a comparison has been made with a scenario in which no additional wind power would be installed after 2006. The differences between the two cases are attributed to the incorporation of wind power.

From a planning and operational perspective, integrating wind generation into the U.S. electricity grid at the 20% level appears to be technically feasible without significantly and unrealistically constraining the WinDS model (e.g., assuming no new transmission will be built). In addition to modeling the expansion of the electricity grid to transmit power from wind-rich geographic areas to demand (load) centers, the model treats wind resource variability on time scales ranging from multiyear capacity planning to minute-to-minute ancillary service requirements. (WinDS does not perform minute-to-minute ancillary service calculations, but it uses statistics to approximate these requirements; see Appendix B for a detailed discussion of the treatment of wind variability.) The 20% Wind Scenario presented here includes future reductions in wind technology costs and increased performance, coupled with transmission system expansion that is favorable to wind energy. These assumptions affect only the direct cost to the electricity sector associated with this level of wind energy expansion. These cost and performance assumptions differ from those used by EIA; the assumptions are based on 2006 market data developed by Black & Veatch for all generation technologies. Explicit cost and performance projections are used rather than learning algorithms generally used by EIA. See Appendix B for more information.

A.2 Methodology

The WinDS model was used to identify some key components of the impacts of producing 20% of the nation's electricity from wind energy by 2030. WinDS is a geographic information system (GIS) and linear programming model of electricity capacity expansion for the U.S. wholesale market.[13] The model operates over multiple regions and time periods. Generation capacity expansion is selected to achieve a cost-optimal generation mix to meet 20% wind generation over a 20-year planning horizon for each 2-year period from 2000 to 2030.

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The assumptions used for the WinDS model were obtained from a number of sources, including technical experts (see Appendix D), the WinDS base case (Denholm and Short 2006), AEO (EIA 2007), and a study performed by Black & Veatch (2007). These assumptions include projections of future costs and performance for all generation technologies, transmission system expansion costs, wind resources as a function of geographic location within the continental United States, and projected growth rates for wind generation. Appendix B describes these assumptions in detail.

A.2.1 Energy Generation Technologies

Wind-generation technologies are contained in the WinDS model, along with conventional technologies such as coal plants (pulverized coal and integrated gasification combined cycle [IGCC]), nuclear plants, and natural-gas-fired combustion turbine and combined cycle plants. The model does not include technologies installed "behind the meter," such as cogeneration or other distributed generation systems, nor does it include energy efficiency or demand response technologies. Table A-1 summarizes the modeling assumptions.

Wind technology options include land-based and offshore technologies. Wind resource classes 3 through 7 (at 50 meters [m] above ground level) are specified for 358 wind supply regions across the continental United States. Each wind supply region in WinDS includes a mix of these wind resource classes. Offshore wind resources are associated with coastal and Great Lakes regions. Resource maps reference those produced by the Wind Powering America (WPA) initiative or by individual state programs, and include environmental and land use exclusions. In

[13] The model, developed by NREL's Strategic Energy Analysis Center (SEAC), is designed to address the principal market issues related to the penetration of wind energy technologies into the electric sector. For additional information and documentation, see http://www.nrel.gov/analysis/winds/.

Table A-1. Assumptions used for scenario analysis

	Scenario Assumptions
Renewable Energy Technologies (other than wind)	• Contributions to U.S. electricity supply from renewable energy (other than wind) are held constant at 2006 levels through 2030
Land-Based Wind Technology Cost	• $1,730/kW in 2005 and 2010, decreasing 10% by 2030 • Regional costs vary with population density, with an additional 20% in New England
Shallow Offshore Wind Technology Cost	• $2,520/kW in 2005, decreasing 12.5% by 2030
Wind Technology Performance	• Capacity factor improvements about 15% on average over all wind classes between 2005 and 2030
Existing Transmission	• 10% of existing transmission capacity available to wind plants at point of interconnection
New Transmission	• Transmission will be expanded • $1,600/megawatt-mile (MW-mile) • 50% of cost covered by wind project • Regional cost variations prescribed as follows: 40% higher in New England and New York, 30% higher in Pennsylvania-New Jersey-Maryland (PJM) East interconnection, 20% higher in PJM West, 20% higher in California
Wheeling Charges	• No wheeling charges between balancing areas
Conventional Generation Technology Cost and Performance	• Natural gas plant cost ($780/kW in 2005) and performance flat through 2030 • Coal plant capital cost ($2,120/kW in 2005) increases about 5% through 2015 and then remains flat through 2030 • Coal plant performance improvement of about 5% between 2005 and 2030 • Nuclear plant capital cost ($3,260/kW in 2005) decreases 28% between 2005 and 2030 • Nuclear plant performance stays flat through 2030
Fuel Prices	• Natural gas prices follow AEO high fuel price forecast • Coal prices follow AEO reference fuel price forecast • Uranium fuel price is constant

addition to the geographic display of wind resources, seasonal and diurnal variations in capacity factor (CF) are computed based on wind resource data. Appendix B contains more information about the wind resource data used for this study.

Experts at Black & Veatch Corporation developed wind technology cost and performance projections based on their experience and market knowledge, discussions with wind industry professionals, and review of cost and performance trends (Black & Veatch 2007). Wind technology costs in 2005 are assumed to be $1,730/kW[14] (kilowatt; in real US$2006), which reflects recent cost increases attributed to current exchange rates between the euro and the dollar, increased commodity prices, a constrained supply of wind turbines, and construction

[14] All dollar values in appendices A and B are in $US2006. These capital costs include construction financing, which adds approximately 5% to the "overnight" capital cost given in Appendix B. The WinDS model applies financing costs in each solution period that requires overnight capital costs as input.

financing. Wind technology costs are projected to decrease to $1,550/kW by 2030 (in US$2006 including construction financing). The cost of offshore wind energy technology is projected to decrease 12.5% over the same period, from $2,500/kW in 2005 to $2,200/kW in 2030 (real US$2006 including construction financing).

Specialists at Black & Veatch developed wind technology performance projections, in the form of capacity factors, by extrapolating historical performance data from 2000 to 2005. Appendix B gives more details on the cost and performance estimates for current and future years for both land-based and offshore wind technologies.

Black & Veatch experts also developed conventional generation technology cost and performance projections based on reported engineering, procurement, and construction costs for currently proposed plants through 2015. Fossil plant costs were assumed to remain flat beyond 2015 with modest performance improvements for coal plants. Cost and performance projections for nuclear plants assume continued technology development. Appendix B presents these cost and performance assumptions.

A.2.2 Transmission and Integration

Wind energy can be used to meet local loads (i.e., loads in the same wind supply region), as well as those in other geographic locations. Local loads can be met either by transmitting on the existing grid where capacity is available (10% of the capacity of each existing line is assumed to be available for wind) or by building a short, dedicated transmission line directly to the local load. Wind energy can also be transmitted to another locale, either on the existing grid when capacity is available or on a new transmission line. If the transmission line crosses between two balancing areas, there must be enough capacity on the line in each seasonal or diurnal time frame to take advantage of wind's full nameplate capacity, as well as the energy associated with other generators transmitting power over that line. If no capacity remains on that transmission line, the model assumes that a dedicated transmission line will be constructed for wind.

When integrating wind resources into the grid, the model considers both planning and operating reserve margins for all North American Electric Reliability Corporation (NERC) regions. For both types of reserve margin, WinDS accounts for the variability that occurs when wind generation is used from disparate wind sites whose output is not fully synchronized. The wind plant's capacity value is a function of the CF, seasonal and diurnal wind variations, and correlation with existing wind capacity installations. In this way the variability of the wind resource is assessed in combination with conventional generation within each NERC region.

The transmission system is assumed to expand under large, regional operation and planning entities, which incorporate polices that favor wind energy. Operating grid systems on large, regional bases, such as through the Midwest Independent Transmission System Operator (Midwest ISO), mitigates the variability of wind power. The WinDS model calculates reserve and planning margins at the NERC regional level, which is representative of these large operating structures. A wind energy penetration limit of 25% has been assumed at the interconnect level. Also, based on the participant funding principle adopted by Midwest ISO, the cost of new transmission is assumed to be split equally between the originating project, be it wind or conventional generation, and the ratepayers within the region. This tariff structure is assumed to apply nationwide. The exception is for new transmission lines that are built at a project in one interconnection region to meet loads in another interconnection region. In this case, the transmission cost is borne entirely by the project. Consistent with the large, regional planning process, this scenario assumes that there are no wheeling charges between balancing areas. Finally, the 20% Wind Scenario assumes that 10% of existing grid capacity is available for wind energy.

A.2.3 Quantification of Impacts

Projected electricity demand estimates, as well as financing and economic assumptions, were obtained from the AEO reference case (EIA 2007). Total direct costs of all generation technologies were estimated over a 20-year planning horizon in each two-year solution period. The sum of these direct costs represents the total cost to the electricity sector for generation choices through 2030, including costs for capital investment, operations and maintenance (O&M), new transmission, and fuel.

To calculate the impacts of 20% wind energy, the authors of this report constructed the aforementioned No New Wind Scenario. This scenario assumes that the conventional generation mix expands to meet electricity demand with currently enacted policies. Table A-1 outlines the major assumptions in the scenario and supporting analyses. The difference between the two cases, 20% Wind and No New Wind, represents the impact of wind energy.

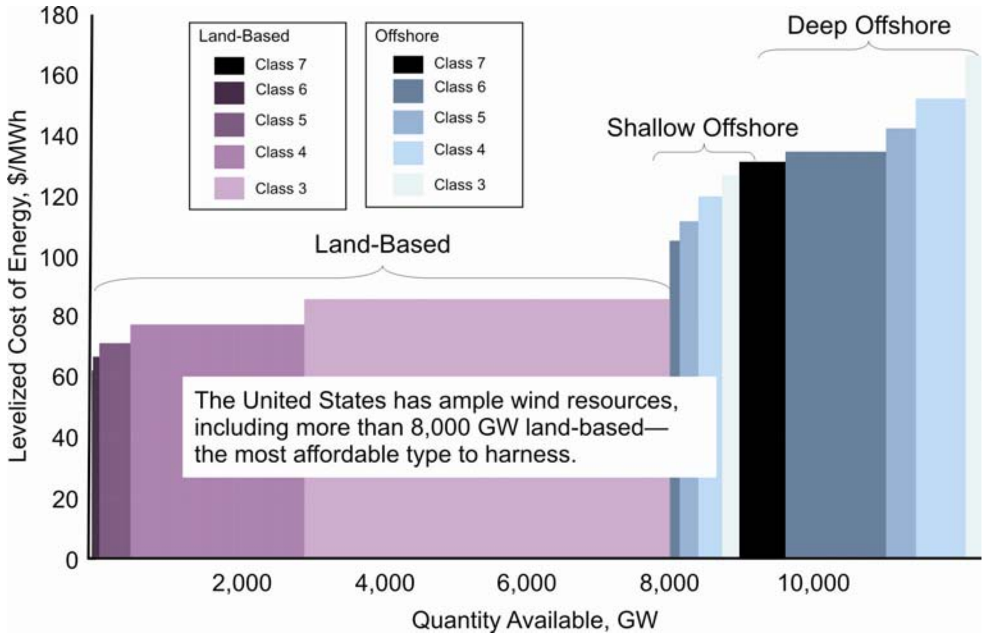
A.3 Wind Capacity Supply Curves

In economic analysis, a supply curve is used to determine the quantity of a product that is available at various prices. For this report, wind generation potential is plotted against its calculated levelized cost (LC) of electricity in ascending order. See Appendix B for more information. For example, the potential (in gigawatts) from high-speed wind resources has been plotted against its levelized cost (dollars per megawatt-hour [MWh]); lower-speed wind projects have higher costs and represent the next step up on the supply curve. Cost and potential were estimated for each region based on a GIS optimization strategy developed by NREL. The regions were aggregated such that an overall supply curve for national wind potential could be developed. The following supply curves compare the quantities and costs for wind resources and show which products can be brought to market at the lowest cost (resources on the left side of Figure A-2 “Supply Curve for wind energy: current bus-bar energy costs”). See Appendix B for wind resource estimates.

The national supply curve for bus-bar energy costs—for the wind plant alone, excluding transmission costs—is shown in Figure A-2. The figure illustrates that more than 8,000 GW of wind energy is available in the United States at $85/MWh or less. This is a huge amount of capacity, equivalent to roughly eight times the existing nameplate generating capacity in the country, which is estimated at 983 GW (EIA 2007). This price, however, excludes the cost of transmission or integration. The supply curve uses today’s cost and performance figures, which are projected to improve with future technology development.

The supply curve shows the simple relationship between wind power class and cost, as the higher classes are the lowest cost (and least abundant resources); Classes 3 and 4 are much more prevalent. At today’s costs, offshore wind is not cost-competitive with land-based wind technologies. Finally, the national resource potential for land-based wind technologies exceeds the existing nameplate generating capacity in the country by a factor of eight. However, that does not mean capturing that full potential is economically, technically, or politically viable.

Figure A-2. Supply curve for wind energy—current bus-bar energy costs



The national supply curve in Figure A-3 shows the costs of connecting to the existing transmission system, given that 10% of capacity is available for new wind generation. This supply curve also shows the cost of connecting directly to load centers that are in the same balancing area as the wind resource, given that a maximum of 100% of that load can be served by wind. This curve is produced as an input to the WinDS model. Please see Appendix B or (Black & Veatch 2007) for more information.

Figure A-3. Supply curve for wind energy: energy costs including connection to 10% of existing transmission grid capacity

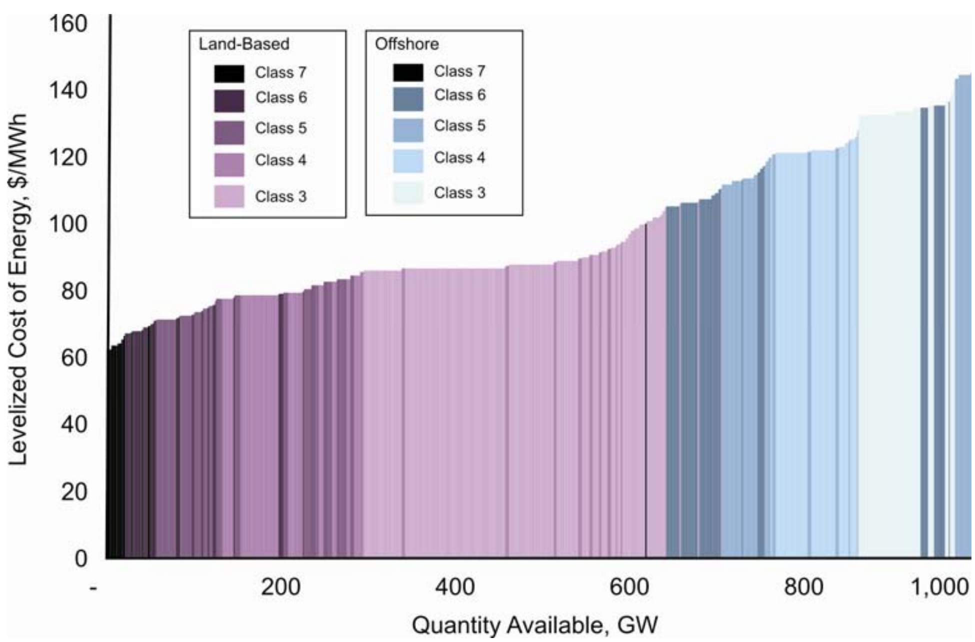
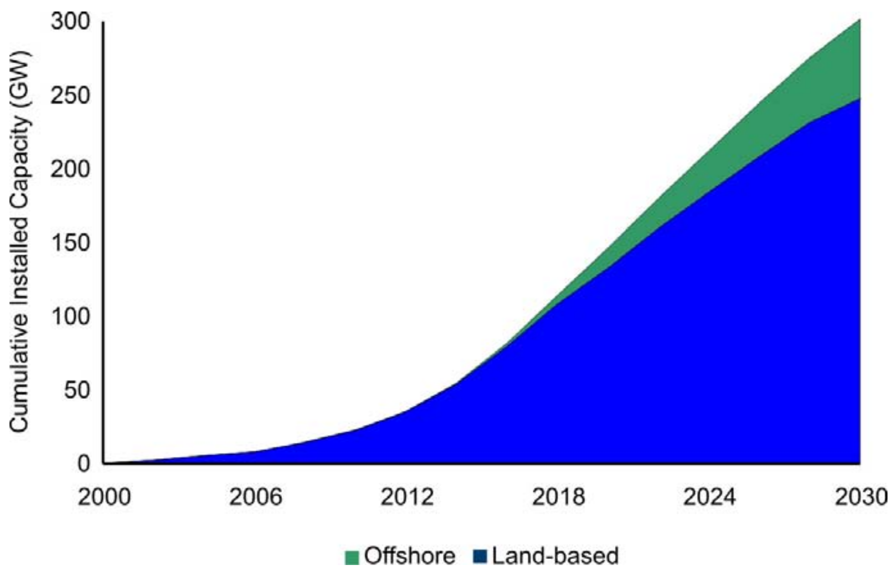


Figure A-3 shows only the supply curve for wind projects that can enter the existing transmission system (or that can power nearby loads), and does not include wind projects that would require new transmission to deliver power to markets distant from the generation system. The supply curve, however, shows more than 1,000 GW of wind energy— approximately 600 GW of land-based and roughly 400 GW of offshore capacity. Developing all of this resource is not economical and would require significant modifications in the transmission system, but under certain conditions it could produce enough energy to greatly exceed 20% of the nation's electricity supply in the future. The supply curve further illustrates that more than 600 GW of wind are available at or below $100/MWh at current bus-bar energy costs and performance indicators. These supply curves do not factor in transmission or integration costs or technology improvements.

A.4 Impacts

Based on the assumptions used to create the 20% Wind Scenario, providing 20% of the nation's projected electricity demand by 2030 would require the installation of 293.4 GW of wind technology (in addition to the 11.4 GW currently installed) for a cumulative installed capacity of 304.8 GW, generating nearly 1,200 terawatt-hours (TWh) annually. Offshore wind technology would account for about 18% (54 GW) of total wind capacity by 2030. Figure A-4 shows the cumulative installed capacity of land-based and offshore wind technologies required to generate 20% of projected electricity demand by 2030.

Figure A-4. Cumulative installed wind power capacity required to produce 20% of projected electricity by 2030



A.4.1 Generation Mix

This section presents impacts on the remaining generation mix and on the emissions of carbon from producing 20% of the nation's electricity from wind in 2030. The geographic distribution of wind turbines and the transmission expansion required to accommodate them are also addressed. Sophisticated routines in the WinDS model use existing transmission or build new transmission while incorporating associated wind integration costs. This scenario shows that with wind technology advancement associated reductions in costs and changes in the grid system, producing 20% wind energy in the nation's portfolio by 2030 could be technically feasible.

The generation mix produced by the WinDS model based on the requirement that 20% electricity generation will come from wind is pictured in Figure A-5. This scenario does not assume that carbon regulation policies are in place and reflects the assumptions listed in Table A-1 as well as others. The resulting generation mix, excluding wind, is made up of the most cost-effective conventional technologies in place today. Wind energy grows as a percentage of the nation's generation mix, and coal-generated electricity remains the major generation technology in 2030. Nuclear power generation declines slightly as a fraction of the total generation mix. Natural gas technologies make a greater contribution to the total mix through 2016 and then decline to a level similar to today's level by 2030. Changes in assumptions would produce a different mix of conventional generation technologies.

Figure A-5. 20% Wind Scenario electricity generation mix 2000–2030

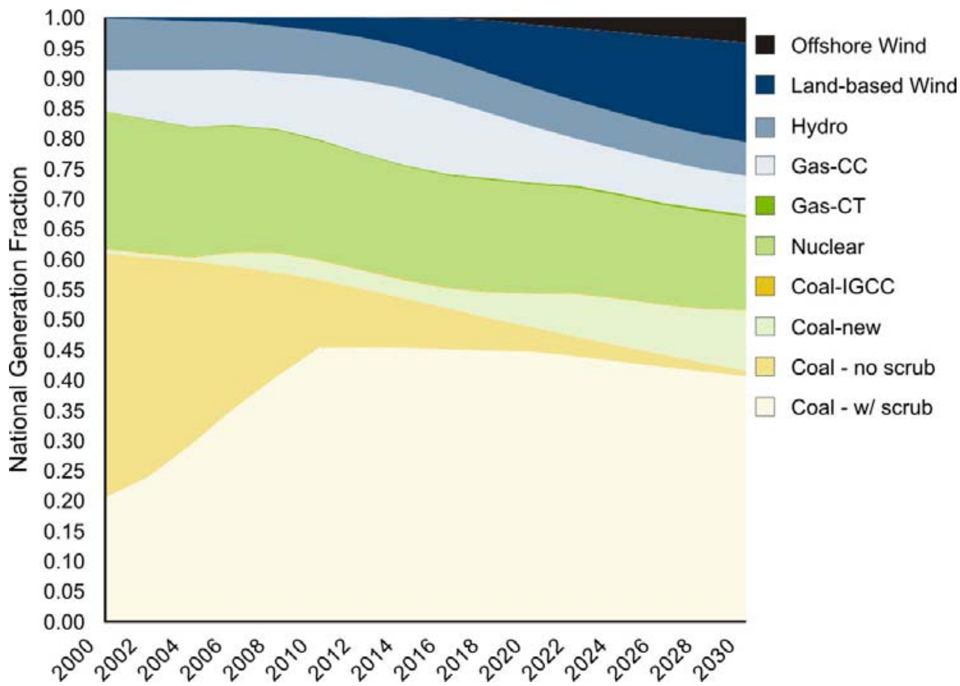


Figure A-6 illustrates the comparison in net generation in 2030 between conventional energy and wind energy generation, when applied to the 20% Wind and the No New Wind Scenarios. The 20% Wind Scenario, of course, would result in dramatically higher levels of wind energy generation. This figure also shows a significant reduction of energy generated from combined cycle natural gas plants (Gas-CC) as well as reduced energy from new pulverized coal plants (Coal-New). Figure A-7 compares generating capacity by 2030 between the 20% Wind Scenario and the No New Wind Scenario. Again, the contribution from wind is the primary difference. The 20% Wind Scenario requires less Coal-New and Gas-CC capacity.

The 20% Wind Scenario does require additional gas combustion turbine capacity (Gas-CT) to maintain grid reliability when wind resources vary. As shown in Figure A-6, relatively little electricity is generated from these plants in both scenarios.

Figure A-6. Generation by technology in 2030

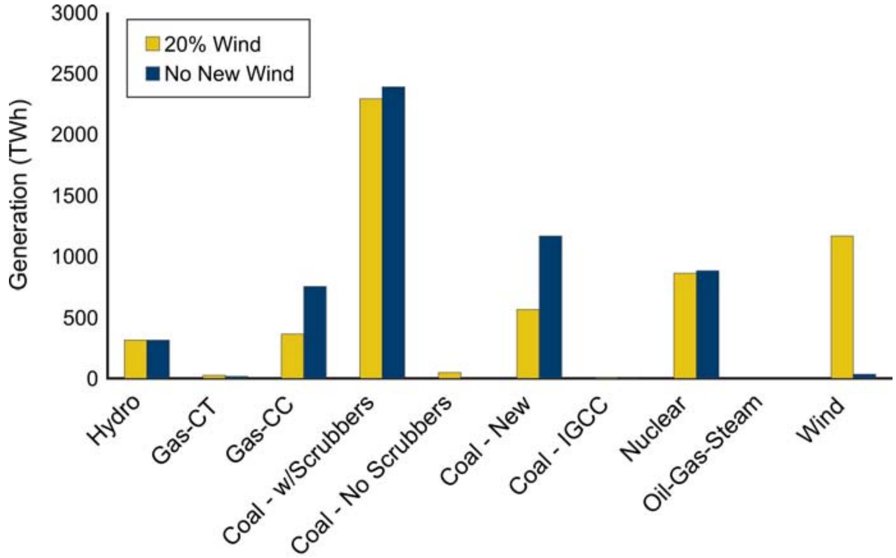
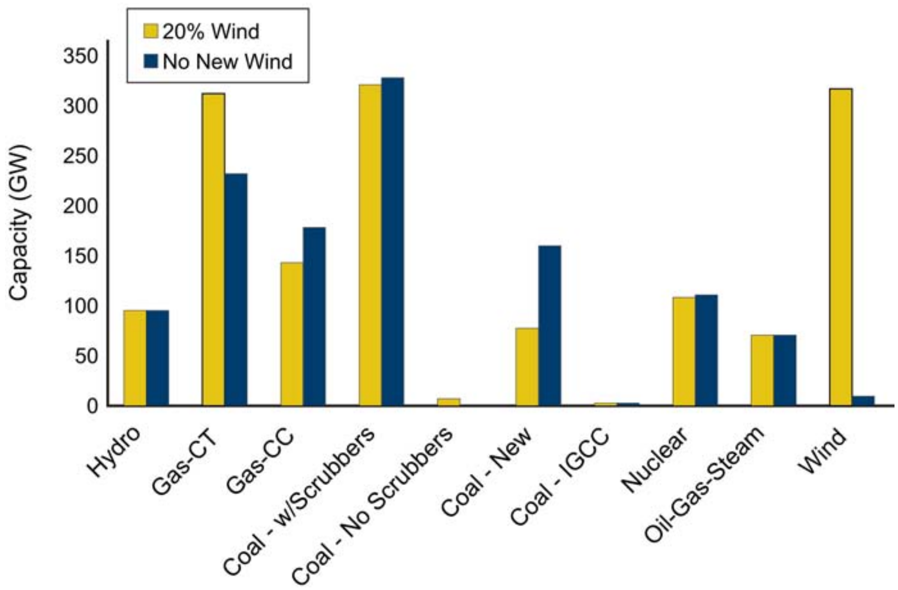


Figure A-7. Capacity by technology in 2030



Several important assumptions could affect the resulting mix of conventional generation in output from the WinDS model, including the following:

- **Fuel price forecasts:** The WinDS model uses regional gas and coal fuel price projections from the AEO (EIA 2007*)*. The reference-case coal fuel projections were implemented, but the natural gas price forecast from the high-price case was deemed more probable. Other gas and coal future price projections could be used, and modifying these prices would affect generation from gas, coal, and other sources.
- **Fuel price elasticity:** For this analysis, the WinDS model does not include fuel price elasticity. This could be important in scenarios that differ significantly from the scenario assumed in the AEO (EIA 2007). For example, assuming wind generation at 20% of U.S.

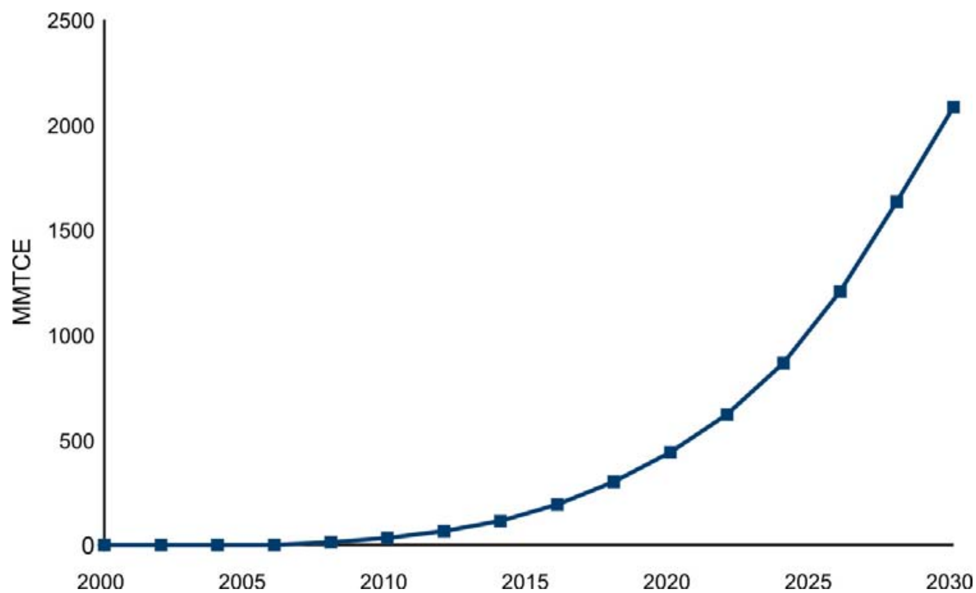
electricity, the demand for gas and coal would decrease, resulting in a lower price for both (thereby conversely driving up demand) and settling on a cost value lower than that currently used in the model.

- **Carbon regulation:** The imposition of a carbon constraint would also change this generation mix significantly, increasing future Coal-IGCC and Nuclear capacity, reducing future Coal-New and Gas-CC capacity, and leading to significantly more plant retirements and less use of existing coal plants.

A.4.2 Carbon Emission Reduction

Comparing the 20% Wind Scenario with the No New Wind Scenario provides one way of estimating the potential carbon emissions reductions that could be attributed to wind energy. This scenario assumes that the conventional generation mix is allowed to expand while optimizing total costs without any carbon regulation policy. Figure A-8 illustrates the cumulative carbon emissions reduction of more than 2,100 million metric tons of carbon equivalent (MMTCE) attributed to producing 20% of the nation's electricity from wind during the significant wind energy expansion period, 2005 to 2030. Extrapolating cumulative carbon emissions avoidance over the 20-year wind plant life through 2050 results in avoided emissions of more than 4,000 MMTCE, and avoided carbon emission in 2030 alone of 225 MMTCE.

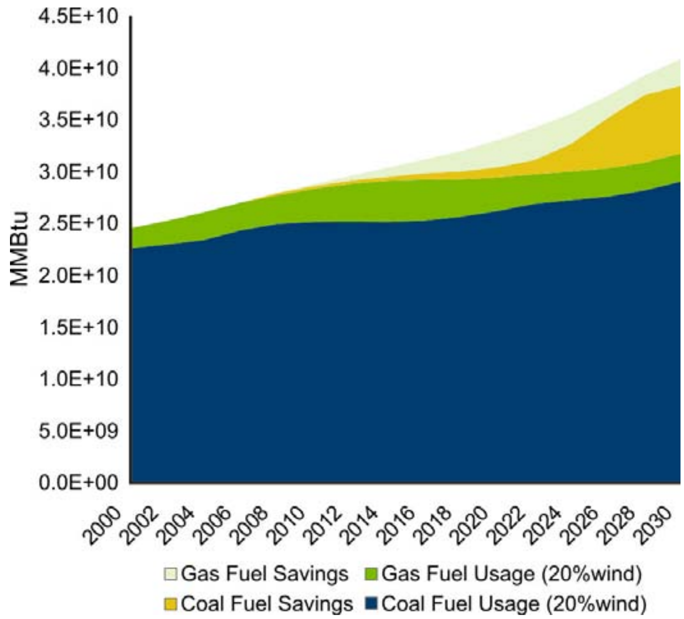
Figure A-8. Cumulative carbon emission reductions attributed to wind energy (compared to expanding the generation mix without wind energy)



A.4.3 Reduced Natural Gas Demand

Figure A-9 demonstrates the decrease in coal and gas fuel use for the 20% Wind Scenario relative to the No New Wind Scenario. This graph indicates that a reduction in coal use across all coal technologies and a reduction in natural gas use comprise a significant portion of the total amount that would be used without additional wind installations. Incorporating enough wind generation technology to produce 20% of the nation's electricity demand by 2030 could reduce the electricity sector's natural gas requirements by about 50% and its coal requirements by about 18%. This shift translates into a reduced national demand for natural gas of 11%.

Figure A-9. Fuel usage and savings resulting from 20% Wind Scenario



Wind power offers the country important resource diversification benefits, including the prospect for moderating natural gas demand. In 2006, gas-fired generation accounted for nearly 20% of the nation's electricity generation capacity. Because of the way electricity markets operate, the price of gas-fired generation determines the price of electricity. Wellhead natural gas prices, which hovered near \$2/MMBtu in the 1990s, have risen to more than \$6/MMBtu, and most forecasts expect prices to remain high relative to historical standards. Past efforts to forecast natural gas prices have not been very successful (e.g., Wiser and Bolinger 2004 and Bolinger and Wiser 2006).

A.4.4 Land Use

Under the 20% Wind Scenario, wind turbines required to supply 20% of the nation's electricity (over 300 GW) would be broadly distributed across the United States; at least 100 MW would be installed in 43 of the 48 contiguous states. Hawaii and Alaska have not been represented in this study, but both states are expected to install more than 100 MW of wind capacity. The WinDS model uses the best available assessment of local wind resources to expand wind technology capacity. Limitations of wind resource input data, which could significantly affect the wind technology capacity installed in a given state, are discussed in Appendix B. In addition to wind resources, other factors related to the model logic can influence the amount of wind capacity installed in a given state. For instance, current long-term power purchase agreements are not implemented in WinDS. The model assumes that local load is met by the generation technologies in a given region.

The lack of wind capacity installed in Ohio is assumed to be primarily a result of the amount of existing conventional energy resources that supply the state, reducing the need for additional generating capacity, regardless of the fact that Ohio's wind resources are sufficient to support wind technology development. Additionally Ohio's wind resources are concentrated in the western part of the state. The transmission cost assumptions are higher in Ohio than in neighboring Indiana and

Michigan, which makes Ohio's wind resource appear less cost-effective in comparison. Some states such as Louisiana, Mississippi, and Alabama have lower quality wind resources than Ohio, but under the right economic circumstances some wind energy development could occur in those states. The WinDS model optimizes the installation of wind energy capacity within each of the three large interconnection areas in the United States. The model shows that broad geographic distribution of wind energy capacity serves to meet the broadly distributed national electricity load. Figures A-10 to A-13 illustrate capacity expansion of wind energy representing the years 2012, 2018, 2024, and 2030 (approximately 3%, 9%, 15%, and 20% electricity generation, respectively). The specific assumptions used in this model significantly affect each state's projected wind capacity. See Table A-1 and Appendix B for more information on the assumptions.   In reality, these levels will vary significantly as electricity markets evolve and state policies promote or restrict wind energy production.

The black outline in each state in Figures A-10 to A-13 represents land area required for a wind farm, corresponding to the capacity shown on the green scale. These figures use standard exclusion practices, which are detailed in Appendix B. The total land area of the United States required for 305 GW of wind energy, assuming a turbine density of 5 MW per square kilometer (km^2), would be smaller than 61,000 km^2 (50,000 km^2 for land-based projects and 11,000 km^2 for offshore projects). Only about 2% to 5% of the wind farm area, which is represented by the brown square within each black outline, is occupied by towers, roads, and other infrastructure components, and the balance of the area remains available for its original use (such as farming or ranching).

Figure A-10. Projected wind capacity installations in 2012

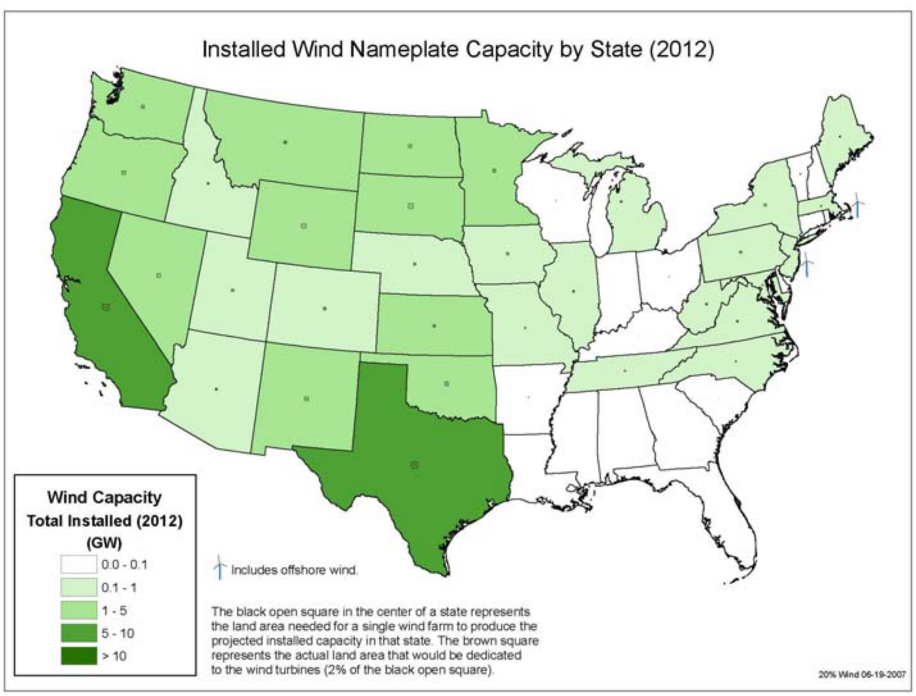


Figure A-11. Projected wind capacity installations in 2018

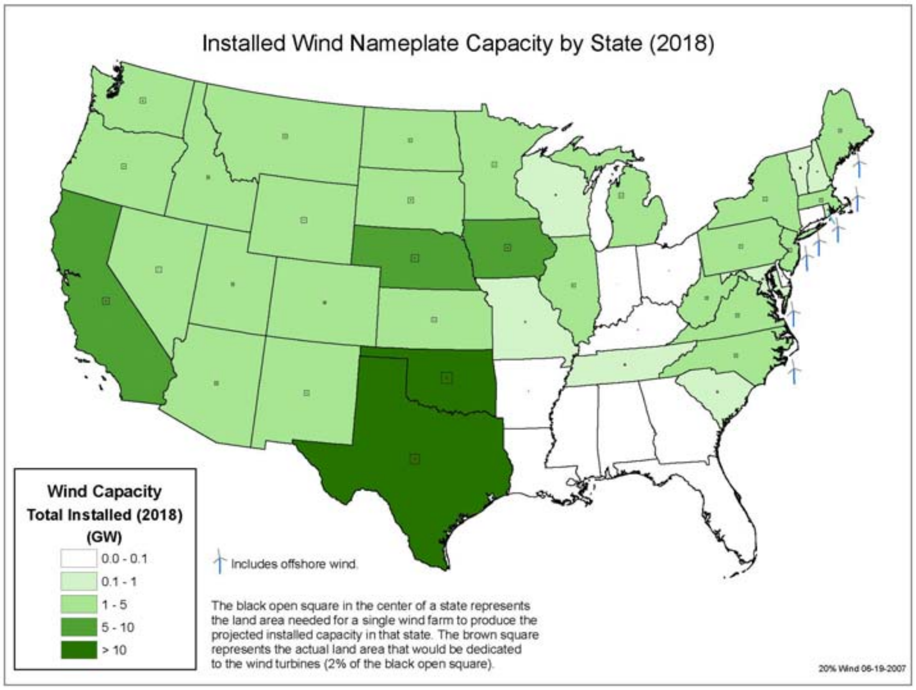


Figure A-12. Projected wind capacity installations in 2024

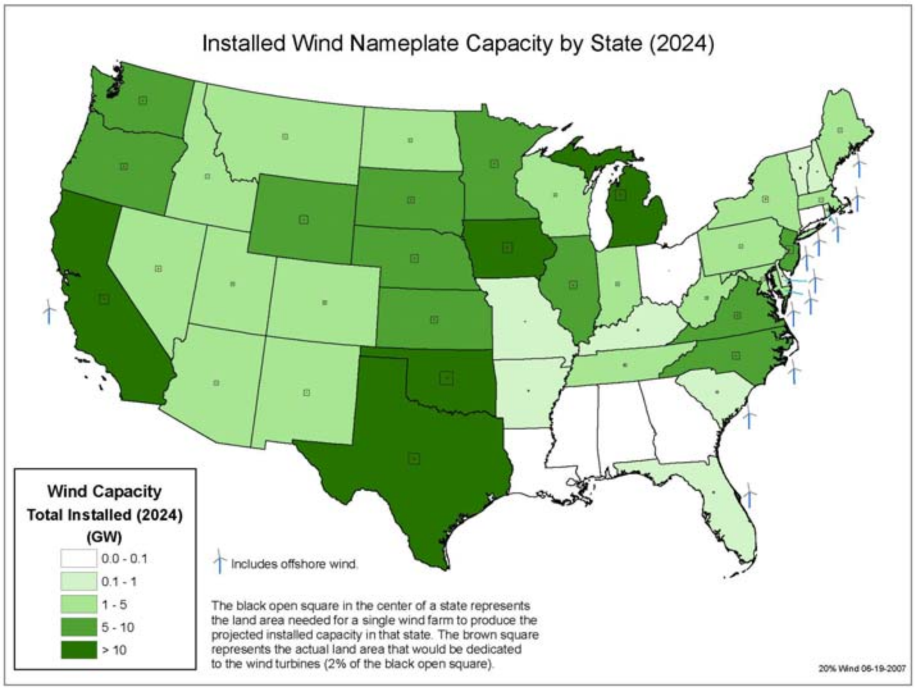
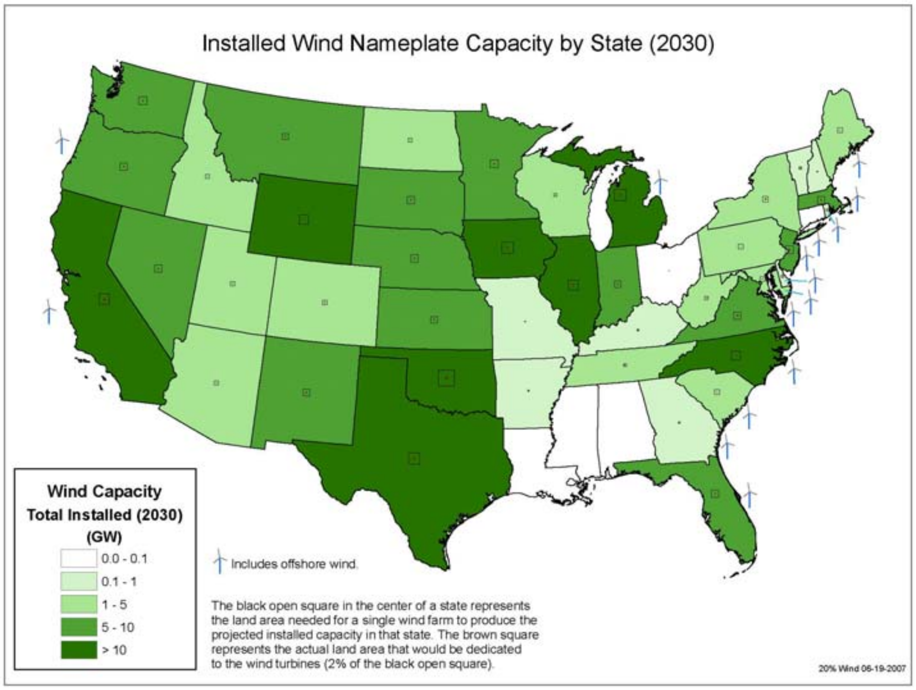


Figure A-13. Projected wind capacity installations in 2030



A.4.5 Transmission

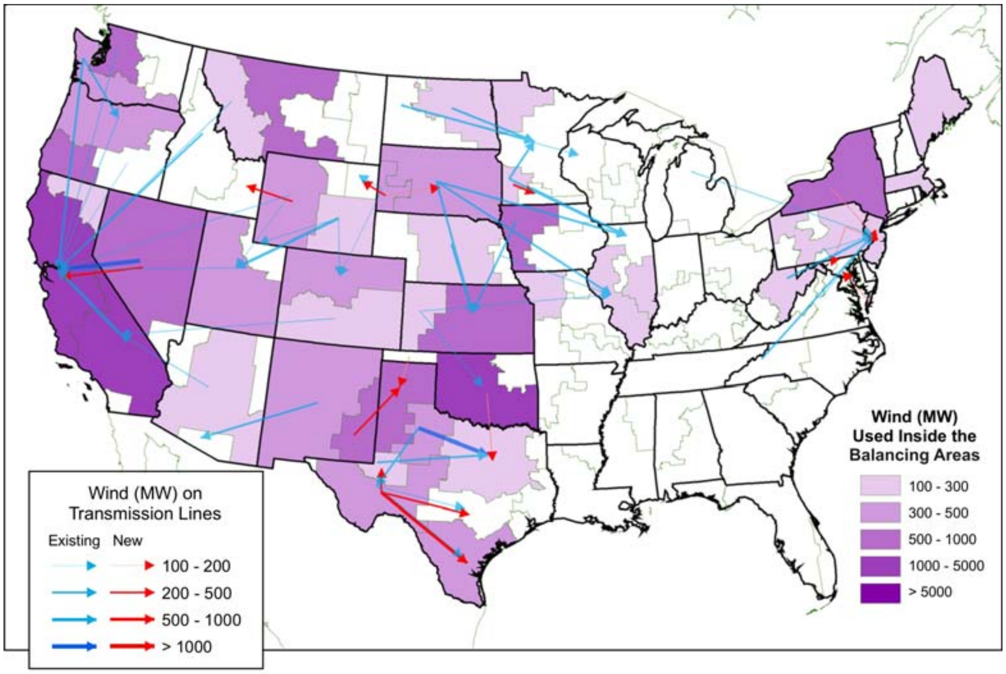
To meet the nation’s growing demand for electricity, significant transmission expansion will be required. Meeting the 20% Wind Scenario requires transmission expansion to accommodate such a geographically dispersed resource. Three types of transmission systems included in the WinDS model could be used to transport wind power around the country:

- **Existing grid:** The model assumes that 10% of the existing grid could be used for new wind capacity, either by improving the grid or by drawing on existing unused capacity.
- **New lines:** The WinDS model can evaluate the use of straight-line transmission lines in the 358 wind regions. The model assumes that appropriate planning will allow new transmission lines to be constructed as additional capacity is needed.
- **In-region transmission:** In any of the 358 wind regions in the United States, the model can assess transmission lines directly from the wind site to loads within the same region.

Figures A-14 to A-17 illustrate the expansion of the transmission system required under the 20% Wind Scenario for the years 2012, 2018, 2024, and 2030 (approximately 3%, 9%, 15%, and 20% wind-electricity generation, respectively).

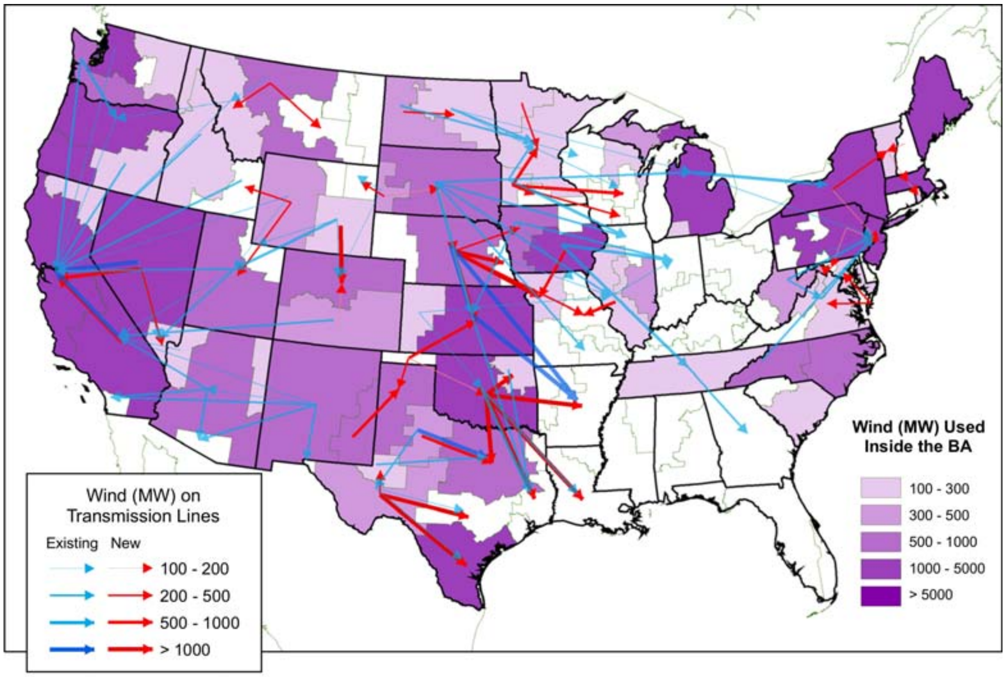
The 20% Wind Scenario assumes that transmission planning and grid operations occur on several levels—planning at the national level, reserve margin constraint planning at the NERC level, and load growth planning and operations at the balancing area (BA) level. For visual clarity, these figures display wind capacity only at the balancing area level.

Figure A-14. Transport of wind energy over existing and new transmission lines projected for 2012



Total Between Balancing Areas Transfer >= 100 MW (all power classes, land-based and offshore) in 2012.
Wind power can be used locally within a Balancing Area (BA), represented by purple shading, or transferred out of the area on new or existing transmission lines, represented by red or blue arrows. Arrows originate and terminate at the centroid of the BA for visualization purposes; they do not represent physical locations of transmission lines.

Figure A-15. Transport of wind energy over existing and new transmission lines projected for 2018



Total Between Balancing Areas Transfer >= 100 MW (all power classes, land-based and offshore) in 2018.
Wind power can be used locally within a Balancing Area (BA), represented by purple shading, or transferred out of the area on new or existing transmission lines, represented by red or blue arrows. Arrows originate and terminate at the centroid of the BA for visualization purposes; they do not represent physical locations of transmission lines.

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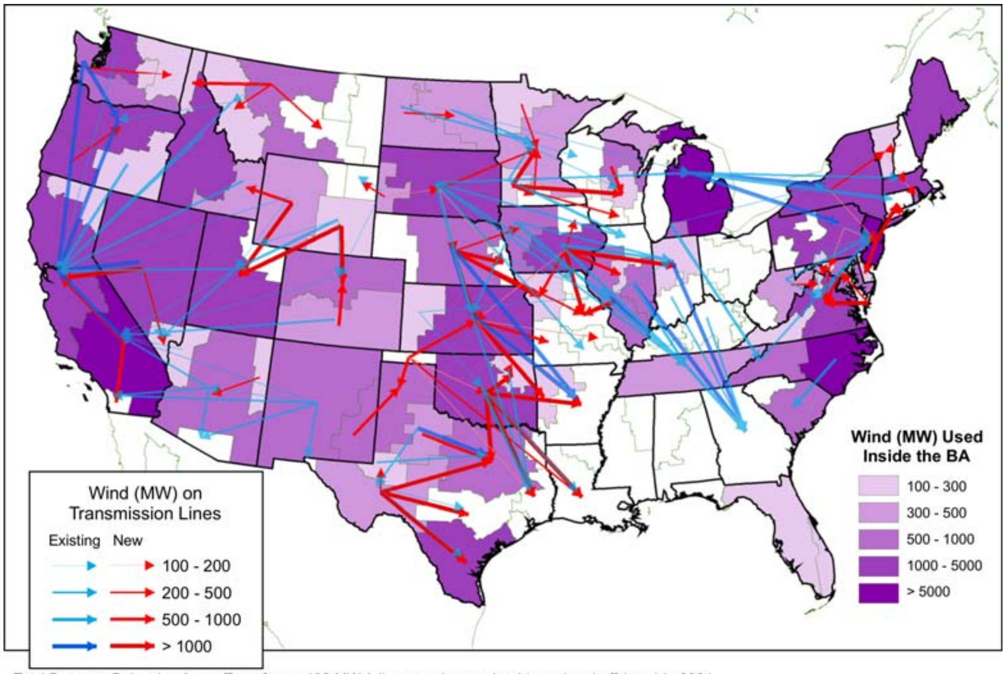
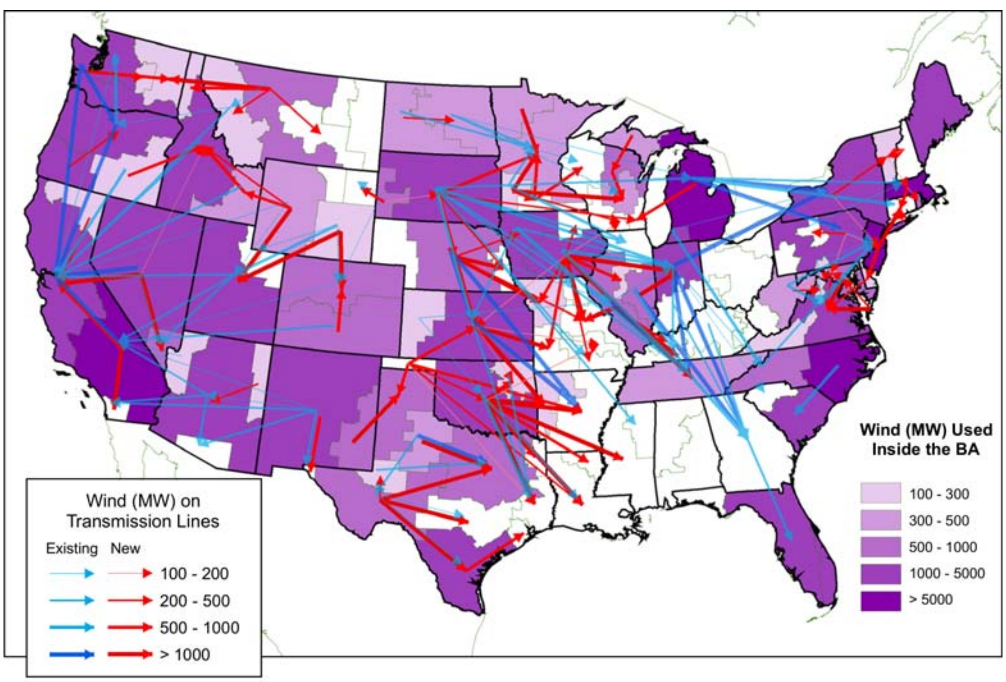
Figure A-16. Transport of wind energy over existing and new transmission lines projected for 2024



Total Between Balancing Areas Transfer >= 100 MW (all power classes, land-based and offshore) in 2024.
Wind power can be used locally within a Balancing Area (BA), represented by purple shading, or transferred out of the area on new or existing transmission lines, represented by red or blue arrows. Arrows originate and terminate at the centroid of the BA for visualization purposes; they do not represent physical locations of transmission lines.

Figure A-17. Transport of wind energy over existing and new transmission lines projected for 2030



Total Between Balancing Areas Transfer >= 100 MW (all power classes, land-based and offshore) in 2030.
Wind power can be used locally within a Balancing Area (BA), represented by purple shading, or transferred out of the area on new or existing transmission lines, represented by red or blue arrows. Arrows originate and terminate at the centroid of the BA for visualization purposes; they do not represent physical locations of transmission lines.

The balancing areas, shaded in purple, depict the amount of locally installed wind, which is assumed to meet local load levels. Generally, the first wind system installed either uses the existing grid or is accompanied by a short transmission line built to supply local loads. In later years, as the existing grid capacity is filled, additional transmission lines are built. New transmission lines built to support load in a balancing area with wind resources within that same area are not pictured in these figures; only transmission lines that cross balancing area boundaries are illustrated.

In each figure, the blue arrows represent wind energy transported on existing transmission lines between balancing areas. The red arrows represent new transmission lines constructed to transport wind energy between balancing areas. The arrows originate and terminate at the centroid of a balancing area and do not represent the physical location of demand centers or wind resources. The location and relative number of red or blue arrows depend on the relative cost of using existing transmission lines or building new lines.

Table A-2 summarizes the projected installed wind capacity in 2030 by transmission type, number of megawatt-miles of transmission, and the resulting average distance traveled by each megawatt. Transmission options are based on a variety of factors; the cost of using existing transmission compared with new transmission can shift the relative amounts significantly. Appendix B contains a more complete discussion of transmission options used in the WinDS model.

Table A-2. Distribution of wind capacity on existing and new transmission lines

Transmission Type	2030 Wind Capacity	2030 MW-Miles	Average Distance Traveled for Each MW
Existing Transmission Lines	71 GW	20 million MW-miles	278 miles
New Capacity Lines within a WinDS region	67 GW	N/A	N/A (estimated at 50 miles)
New Capacity Lines that Cross One or More WinDS Region Boundaries	166 GW	30 million MW-miles	180 Miles

A.5 Direct Electricity Sector Cost

WinDS has been used to estimate the direct costs of meeting 20% of the nation's electricity requirements with wind power in accordance with the 20% Wind Scenario (see Appendix B for detailed calculations of each cost element). Direct costs to the electricity sector for each scenario include the capital costs of wind and conventional energy equipment, as well as transmission, O&M, and fuel costs. External analyses based on the WinDS model have estimated water consumption reductions. By comparing this scenario with a reference case that involves No New Wind generation after 2006, the potential costs of future wind development were estimated as the incremental change between these two scenarios.

Capital and transmission expansion costs are calculated for generation capacity added through 2030. Other costs presented in this section assume a 20-year project life for wind technology installed after 2010. Thus, the incremental differences in fuel consumption, carbon emissions, and water consumption between the two scenarios in 2030 are reduced proportionally for wind systems that achieve a 20-year operational history between 2030 and 2050.

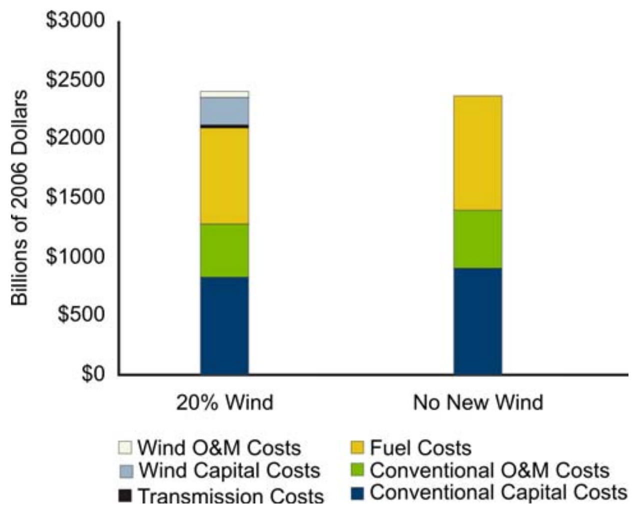
Direct costs to the electricity sector for each scenario include the capital costs of wind and conventional energy equipment, as well as transmission, O&M, and fuel costs. Table A-3 and Figure A-18 illustrate costs for the 20% Wind Scenario as well as the No New Wind Scenario. These costs represent the effect of investment decisions made over 20 years. The primary difference between the two scenarios is the higher capital investment for the 20% Wind Scenario, which is offset somewhat by additional fuel costs for the No New Wind Scenario. Both scenarios show a significant investment—exceeding $2 trillion—in generation capacity expansion through 2030. The capital costs include all financing costs applied to WinDS model investment selection, as described in Appendix B. The discounted capital costs, excluding financing, are $717 billion for the 20% Wind Scenario and $580 billion for the No New Wind Scenario.

Table A-3. Direct electricity sector costs for 20% Wind Scenario and No New Wind Scenario (US$2006)

	Present Value Direct Costs for 20% Wind Scenario* (billion US$2006)	Present Value Direct Costs for No New Wind after 2006* (billion US$2006)
Wind Technology O&M Costs	$51	$3
Wind Technology Capital Costs	$236	$0
Transmission Costs	$23	$2
Fuel Costs	$813	$968
Conventional Generation O&M Costs	$464	$488
Conventional Generation Capital Costs	$822	$905

* 7% real discount rate is used, per Office of Management and Budget (OMB) guidance; the time period of analysis is 2007-2030. WinDS modeling is used through 2030 and extrapolations of fuel usage and O&M requirements are used for 2030-2050.

Figure A-18. Direct electricity sector costs for 20% Wind Scenario and no-new-Wind Scenario



The WinDS model assumes that conventional generation systems, including coal and nuclear plants, are sited near load centers (except for California, which restricts the installation of coal and nuclear plants). Wind resources, on the other hand, tend to be geographically distant from load centers, requiring transmission lines to move electricity to the load. Estimated costs of transmission expansion in the No New Wind Scenario, then, are much lower than those for the 20% Wind Scenario, which might be overly conservative. Assuming that conventional plants are built near load centers is a simplifying assumption for modeling purposes, but may not reflect real siting issues that the coal and nuclear industries face today.

The WinDS model also estimates construction of a portion of a duplicate transmission line to maintain system reliability while expanding transmission capacity, but the model does not explicitly model system reliability conditions and resulting transmission upgrades.

Table A-4 summarizes the key findings of this analysis, focusing on direct electricity sector costs and ignoring the benefits of wind generation in reducing carbon emissions, or reducing water consumption. All costs are shown in US$2006, and the difference between the present values of the two cost streams is the total cost difference; in effect, WinDS calculates the incremental cost of achieving 20% wind (considering costs of capital, O&M, transmission and integration, and decommissioning) relative to the No New Wind Scenario.

Table A-4. Incremental direct cost of achieving 20% wind, excluding certain benefits (US$2006)

Present Value Direct Costs (billion US $2006) [a]	**Average Incremental LC of Wind** ($/MWh-Wind)[b]	**Average Incremental Levelized Rate Impact** ($/MWh-Total)	**Impact on Average Household Customer** ($/month)[c]
43 billion	$8.6/MWh	$0.6/MWh	$0.5/month

[a] Per Office of Management and Budget (OMB) guidance, a 7% real discount rate is used. The time period of analysis is 2007–2030. WinDS modeling is used through 2030 and extrapolations of fuel usage and O&M requirements are used for 2030–2050.

[b] The levelized cost per kilowatt-hour of wind produced is found by solving the following formula: $\sum$ wind generation * LC $/(1+d)^t$ = PV of costs in 20% Wind Scenario–PV of costs in No New Wind Scenario.

[c] Assumes 11,000 kWh/year average consumption.

The result of this analysis suggests rather modest incremental electricity-sector costs.[15] The direct incremental cost of 20% wind is estimated to be $43 billion in net present value terms, increasing electricity rates by only $0.6/MWh on average over the 2007–2050 analysis period, and raising average residential monthly electricity bills by just $0.5/MWh over that same time period. The average incremental LC imposed by each megawatt-hour of wind is estimated at $8.6/MWh. Because WinDS considers not just bus-bar energy costs, but also transmission costs and the cost of integrating the variable output pattern of wind into electricity grids, the analysis presented here suggests that the potential direct costs of achieving 20% wind, relative to meeting load with conventional technologies, need not be overwhelming.

[15] These costs reflect the model inputs and could vary significantly with different fossil fuel price assumptions, carbon taxes or caps, or additional breakthroughs in renewable technologies.

A

A.5.1 Water Consumption Savings

In the energy sector, water is used primarily for cooling in steam plants, but it is also used in boilers and in air pollution reduction processes. Several technologies are used to condense steam (EPRI 2002; Feeley et al. 2005):

- **Recirculating steam plant cooling:** Water is reused to cool steam in a closed-loop system using a cooling tower or cooling pond.
- **Once-through cooling:** Water from a lake, a river, or the ocean is used to condense steam, and the water is then returned to its source, but at a higher temperature.
- **Dry cooling:** Air cools steam, using far less water than the first two "wet" cooling technologies. Although dry cooling is not widely used, it can be the cooling technology of choice where water supplies are limited.

Two types of water use are generally considered:

- **Water withdrawal:** Water is removed from the ground or diverted from a surface source for use.
- **Water consumption:** Water is withdrawn from a source but not directly returned to the source because it is evaporated, transpired, incorporated into products and crops, or consumed by people or livestock.

In this analysis, water consumption projections were made by applying water consumption rates (gallons per megawatt-hour generated) to projected megawatt-hours of generation for each type of power plant. These calculations were made on a yearly basis for the 20% Wind Scenario and No New Wind Scenario. Water savings from deploying large amounts of wind-generated electricity are calculated as the difference in water consumption between the two scenarios. Water consumption rates were developed from several data sources, the most important of which are:

- **EIA Form 767 for 2002:** This database includes water consumption rates for each steam power plant, including the steam portion of combined cycle plants. Because these data often contain unrealistic values for water consumption (e.g., no water consumption or very large amounts of water consumption per megawatt-hour), observations with extremely high and low values have been removed before computing average consumption rates for each type of power plant (EIA 2002).
- **EPRI's water and sustainability study:** This report contains typical water consumption values for steam and combined cycle power plants (EPRI 2002).
- **A Clean Air Task Force/Western Resource Advocates study:** This report supplements the EPRI estimates with other sources of data (Baum et al. 2003).

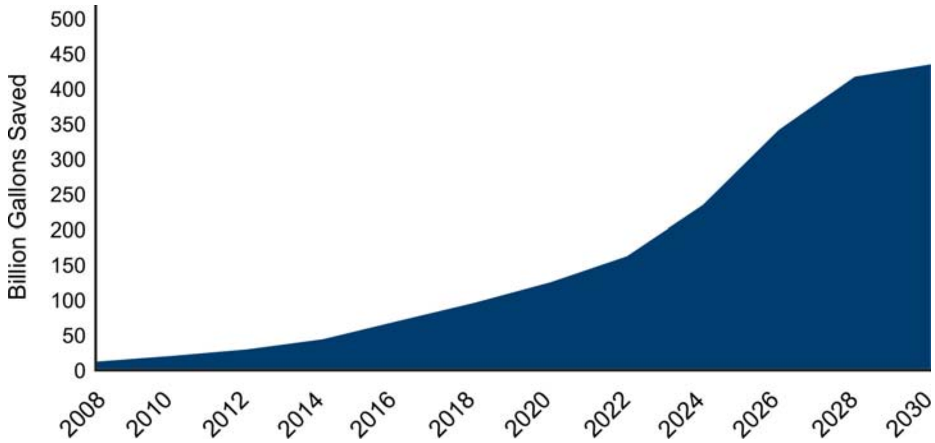
Because of the quality and availability of data from these sources, the authors have assumed in this study that existing and new power plants have the same water consumption rates. Although once-through cooling plants withdraw more water per megawatt-hour than recirculating plants, the mix of power plant cooling types (once-through and recirculating) was assumed to stay the same over the study period. No systematic regional variations in water consumption for coal-fired steam plants were found, and the number of realistic observations for the other technologies was too small to permit a useful geographic disaggregation. Therefore, only national average water consumption rates were used. Table A-5 illustrates water consumption rates used in the analysis, and Figure A-19 shows annual water savings resulting from the deployment of wind resources.

Table A-5. Water consumption rates for power plants

Generation Type	Water Consumption Rate: Gallons per MWh	Source (see list of references for full citation)
Coal-Fired Steam	541	EIA Form 767 for 2002
Gas-Fired Combined Cycle	180	EPRI; Clean Air Task Force & Western Resource Advocates
Nuclear	609	EIA Form 767 for 2002
Oil- or Gas-Fired Steam	662	EIA Form 767 for 2002
Combustion Turbine	0-100	See note below
Wind	0	Clean Air Task Force & Western Resource Advocates

Note: Data on water consumption rates for combustion turbines are sparse. Estimated consumption rates range from 0 to about 100 gall/MWh. For example, the U.S. Department of Energy *Environmental Assessment for the Installation and Operation of Combustion Turbine Generators at Los Alamos National Laboratory* (December 2002) estimated that water use by planned combustion turbines would be 0 (p. 17). A California Energy Commission study (2005) indicated that water consumption for combustion turbines is less than 100 gal/MWh. We analyzed total water savings, assuming combustion turbine water consumption is 0 gal/MWh and 100 gal/MWh and found that the difference in total water savings in any year was only 0.3% or less. Therefore, water savings are not sensitive to assumptions about water consumption rates for combustion turbines.

Figure A-19. Annual water consumption savings due to deployment of wind energy



Displacing large amounts of fossil-fueled power generation with wind energy reduces water consumption. Based on the authors' estimates, if the current conventional generation mix is expanded to meet electricity needs, approximately 51 trillion gallons of water will be consumed for electricity production from 2007 to

2030. If wind energy deployment gradually increases to 20% of the nation's electricity over the same time period, however, 47 trillion gallons of water will be consumed. This is a saving of 4 trillion gallons; an 8% reduction in water consumption. Of the 4 trillion gallons of water saved nationally, 29% will be in the West, 41% will be in the Midwest/Great Plains, 14% will be in the Northeast, and 16% will be in the Southeast (see Table A-6). Extrapolating the savings beyond 2030 to account for the 20-year investment benefit from installing wind energy yields cumulative water consumption savings of 6 trillion gallons by 2050.

Table A-6. U.S. states, by region

Region	States
West	Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Washington, Wyoming, Utah
Midwest/Great Plains	Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Texas, Wisconsin
Northeast	Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont
Southeast	Alabama, Arkansas, Florida, Georgia, Louisiana, Kentucky, North Carolina, South Carolina, Tennessee, Mississippi, Virginia, West Virginia

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A.6 Other Effects

Appendix C describes the jobs and economic impacts directly associated with the manufacturing, construction, and operational sectors of the wind industry.

Other benefits associated with wind energy include an improved environment and better health resulting from reduced particulate or other chemical emissions such as acid rain or mercury, and market benefits including diversification of the electricity sector. These benefits, and others, have not been quantified in this study.

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Appendix B. Assumptions Used for Wind Deployment System Model

To define the 20% Wind Scenario, a number of modifications were made to the National Renewable Energy Laboratory's (NREL) Wind Deployment System (WinDS) base-case assumptions (which are described in the WinDS documentation; see Denholm and Short 2006). These changes include updating wind resource maps, accounting for seasonal and diurnal capacity factor (CF) variations, and including offshore wind resources from South Carolina to Texas. Black & Veatch developed the wind and conventional generation technology cost and performance projections in consultation with American Wind Energy Association (AWEA) industry experts. The assumptions about the large regional planning and operation structure of the transmission system were developed through collaboration with the experts who contributed to Chapter 4. The financial assumptions and the region definitions are unchanged from the WinDS base case. This appendix outlines the assumptions used in constructing the 20% Wind Scenario.

B.1 Financial Parameters

WinDS optimizes the electric power system "build" based on projected life-cycle costs, which include capital costs and cumulative discounted operating costs over a fixed evaluation period. The "overnight" capital costs supplied as inputs to the model are adjusted to reflect the actual total cost of construction, including tax effects, interest during construction, and financing mechanisms. Table B-1 summarizes the financial values used to produce net capital and operating costs. These assumptions are unchanged from the WinDS base case (Denholm and Short 2006) and correspond to assumptions made by the Energy Information Administration (EIA) in the *Annual Energy Outlook 2007 with Projections to 2030* (AEO); (EIA 2007a).

Table B-1. Baseline financial assumptions

Name	Value	Notes and Source
Inflation Rate	3%	Based on recent historical inflation rates
Real Discount Rate	8.5%	Equivalent to weighted cost of capital. Based on EIA assumptions (EIA 2006)
Marginal Income Tax Rate	40%	Combined federal/state corporate income tax rates
Evaluation Period	20 Years	Base Case Assumption
Depreciation Schedule Conventional Wind	15 Year 5 Year	MACRS (Modified Accelerated Cost Recovery Schedule) MACRS (Modified Accelerated Cost Recovery Schedule)
Nominal Interest Rate during Construction	10%	Base Case Assumption
Dollar Year	2004	All costs are expressed in year 2004 dollars.

B.2 Power System Characteristics

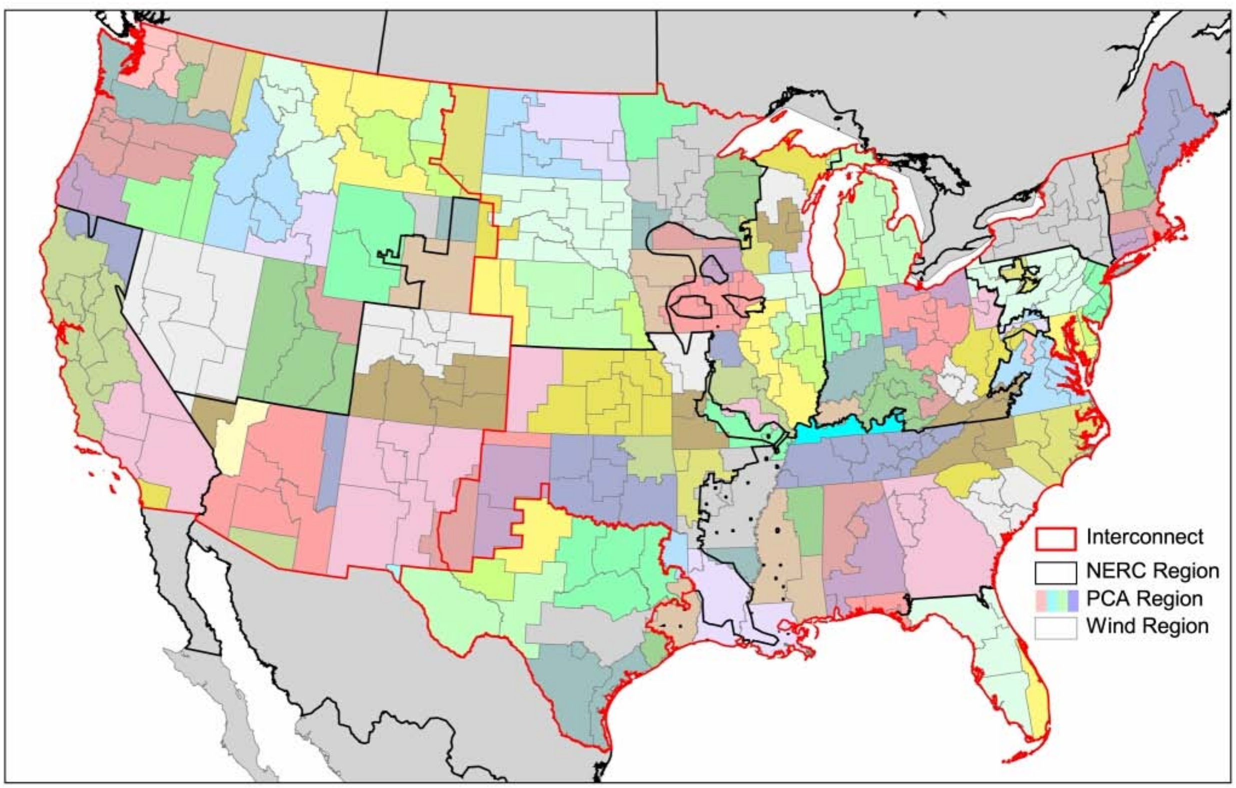
B.2.1 WinDS Regions

Four types of regions are included in the WinDS model (see Figure B-1):

- **Interconnect regions:** There are three major interconnects in the United States (all are electrically isolated): the Eastern Interconnect, Western Interconnect, and the ERCOT (Electric Reliability Council of Texas) Interconnect.
- **National Electric Reliability Council (NERC)[16] subregions:** WinDS uses 13 NERC regions, which are listed in Table B-2.
- **Balancing areas:** WinDS uses 136 balancing areas.
- **Wind resource regions:** There are 358 wind resource regions in WinDS.

Interconnect regions, NERC regions, and balancing areas are defined and operated by various regulatory agencies.

Figure B-1. WinDS regions



[16]For more information on NERC, see http://www.nerc.com/regional/.

Table B-2. NERC regions used in WinDS

NERC Region/ Subregion	Abbreviation	Region Name
1	ECAR	East Central Area Reliability Coordination Agreement
2	ERCOT	Electric Reliability Council of Texas
3	MAAC	Mid-Atlantic Area Council
4	MAIN	Mid-America Interconnected Network
5	MAPP	Mid-Continent Area Power Pool
6	NY	New York
7	NE	New England
8	FRCC	Florida Reliability Coordinating Council
9	SERC	Southeast Reliability Council
10	SPP	Southwest Power Pool
11	NWP	Northwest
12	RA	Rocky Mountain Area
13	CNV	California/Nevada

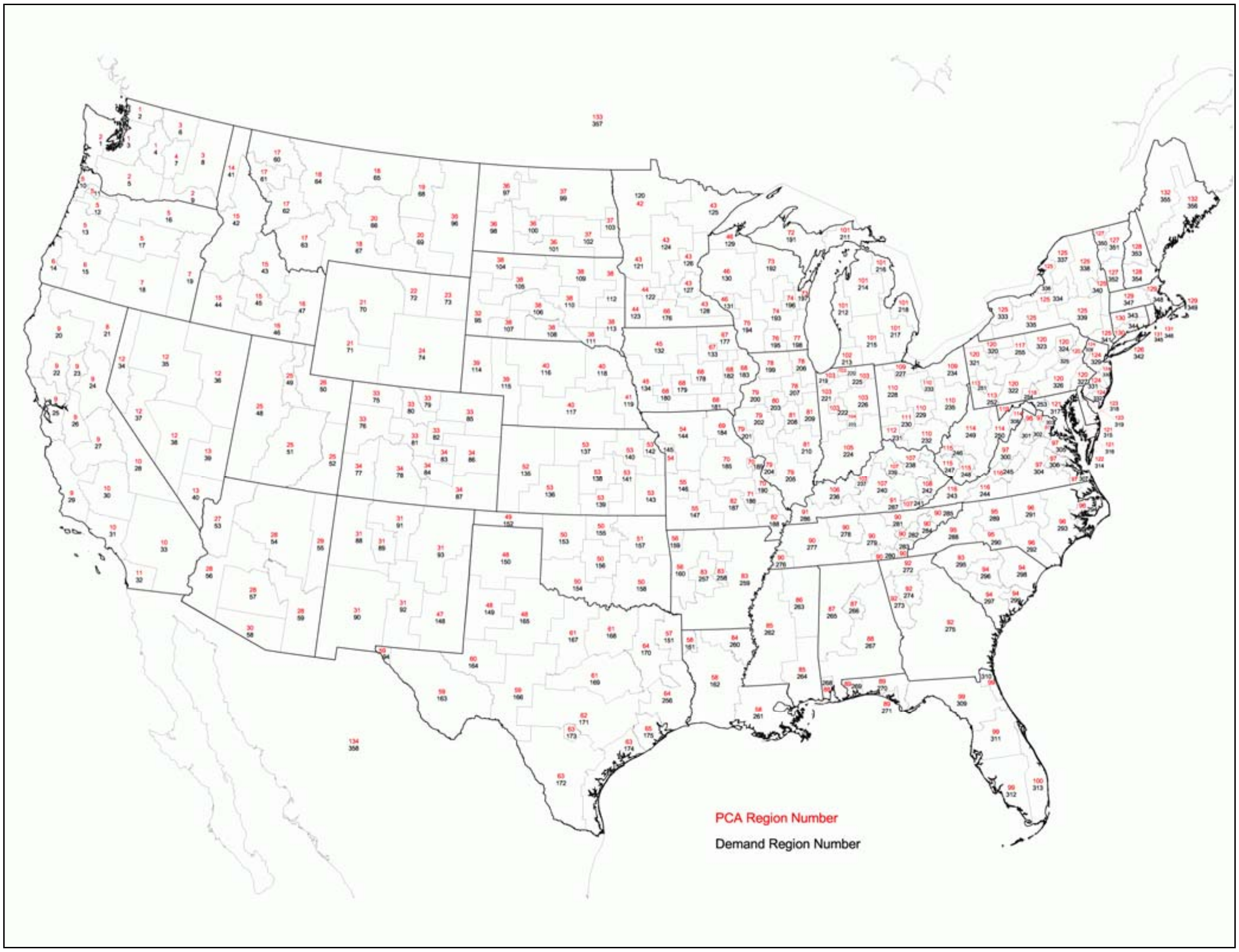
Note: NERC regions in WinDS are based on the pre-2006 regional definitions defined by the EIA (2000). In January 2006, NERC regions were redefined; however, the EIA has not incorporated these changes through publication of an AEO. Therefore, the WinDS will continue to use pre-2006 definitions until the EIA modifies its data. Similarly, some of the recent changes to balancing-area boundaries (now referred to as balancing authorities) are not yet reflected in WinDS (e.g., the formation of the Texas Regional Transmission Organization).

Wind resource regions were created specifically for the WinDS model. These regions were selected using the following rules and criteria:

- Incorporate buildup from counties (so the electricity load can be determined for each wind supply/demand region based on county population)
- Avoid crossing state boundaries (so that state-level policies can be modeled)
- Conform to balancing areas as much as possible (to better capture the competition between wind and other generators)
- Separate major windy areas from load centers (so that the distance from a wind resource to a load center can be well approximated)
- Conform to NERC region/subregion boundaries (so that the results are appropriate for use by integrating models that use the NERC regions and subregions).

Figure B-2 illustrates all wind regions and balancing areas in the United States.

Figure B-2. Wind region and Balancing Areas in WinDS base case



Several components of the WinDS model necessitate using four levels of geographic resolution. For example, electricity demand is modeled at the NERC region level, and wind-generator performance is modeled at the wind-resource region level.

B.2.2 Electric System Loads

Loads are defined by region and by time. WinDS meets the energy and power requirements for each of 136 balancing areas. Energy is met for each balancing area in each of 16 time slices, and within each year modeled. Table B-3 defines these slices.

The electricity load in 2000 for each balancing area and time slice is derived from an RDI/Platts database (Platts Energy Market Data; see http://www.platts.com). Figure B-3 illustrates the WinDS load duration curve (LDC) for the entire United States for the base year, showing the 16 load time slices. For reference, the actual U.S. coincident LDC—also derived from the Platts database—is depicted in the figure as well. The aggregated data for the United States that are shown in Figure B-3 are not used directly in WinDS because the energy requirement is met in each balancing area. This curve does, however, give a general idea of the WinDS

Table B-3. WinDS demand time-slice definitions

Slice Name	Number of Hours Per Year	Season	Time Period
H1	1,152	Summer	Weekends, plus 11:00 p.m. to 6:00 a.m. weekdays
H2	462	Summer	Weekdays, 7:00 a.m. to 1:00 p.m.
H3	264	Summer	Weekdays, 2:00 p.m. to 5:00 p.m.
H4	330	Summer	Weekdays, 6:00 p.m. to 10:00 p.m.
H5	792	Fall	Weekends, plus 11:00 p.m. to 6:00 a.m. weekdays
H6	315	Fall	Weekdays, 7:00 a.m. to 1:00 p.m.
H7	180	Fall	Weekdays, 2:00 p.m. to 5:00 p.m.
H8	225	Fall	Weekdays, 6:00 p.m. to 10:00 p.m.
H9	1,496	Winter	Weekends, plus 11:00 p.m. to 6:00 a.m. weekdays
H10	595	Winter	Weekdays, 7:00 a.m. to 1:00 p.m.
H11	340	Winter	Weekdays, 2:00 p.m. to 5:00 p.m.
H12	425	Winter	Weekdays, 6:00 p.m. to 10:00 p.m.
H13	1,144	Spring	Weekends, plus 11:00 p.m. to 6:00 a.m. weekdays
H14	455	Spring	Weekdays, 7:00 a.m. to 1:00 p.m.
H15	260	Spring	Weekdays, 2:00 p.m. to 5:00 p.m.
H16	325	Spring	Weekdays, 6:00 p.m. 10:00 p.m.

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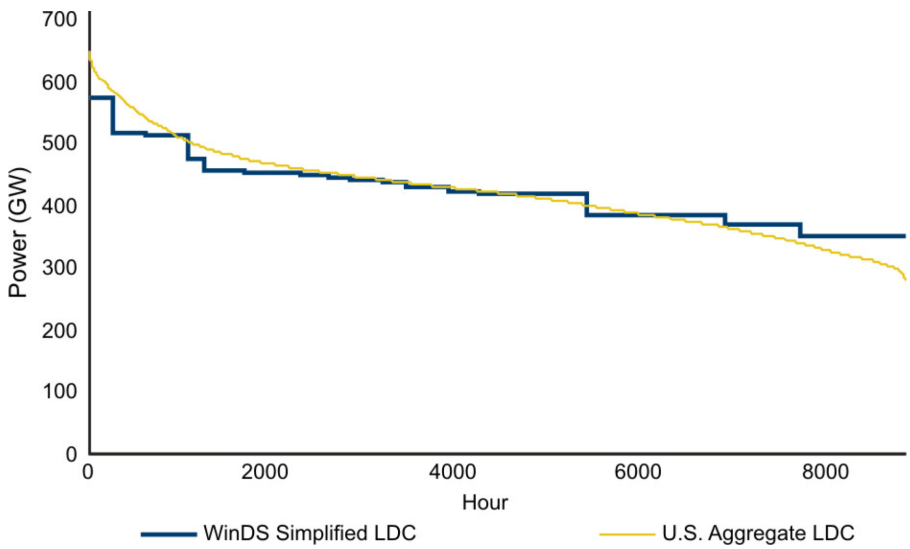
Figure B-3. National load duration curve for base year in WinDS



energy requirement. The LDC does not include the "super peak," which occurs in most systems for a few hours per year. These peak requirements are discussed in Section B.2.4.

B.2.3 Growth Rate

Load growth is defined at the NERC region level. Loads in all balancing areas within each NERC region are assumed to grow at the same rate to 2050. Table B-4 contains the 2000 load and annual growth rates for each NERC region.

Table B-4. Base load and load growth in the WinDS scenario

NERC Region/Sub-Region	Abbreviation	2000 Load TWh/year	Annual Load Growth
1	ECAR	370	1.010
2	ERCOT	205	1.016
3	MAAC	197	1.009
4	MAIN	184	1.010
5	MAPP	110	1.011
6	NY	109	1.006
7	NE	96	1.010
8	FL	141	1.022
9	SERC	589	1.015
10	SPP	132	1.013
11	NWP	176	1.017
12	RA	97	1.022
13	CNV	202	1.017

Source: EIA (2007b)

WinDS assumes that the growth rate in each time slice is also constant (i.e., the load shape remains the same over time).

B.2.4 Capacity Requirements

In each balancing area, WinDS requires that firm capacity be available to meet the demand in each time slice (see the national example of time-slice demand in Figure B-3). In addition, for every NERC and interconnect region, WinDS requires sufficient capacity to meet the peak instantaneous demand throughout the course of the year, plus a peak reserve margin. The instantaneous annual peak load is higher than the load in each of the 16 time slices, because the load in each time slice is the average load over the hours included in that time slice. The reserve margin requirement can be met by any generator type, although the generator must have the appropriate capacity value. In the case of wind power, the actual capacity value is a minority fraction of the nameplate capacity. Section B.6 discusses the treatment of resource variability within the model.

Although these capacity requirements are implemented regionally, Table B-5 illustrates their national impact.

Table B-5. National capacity requirements in the WinDS base case

Capacity Requirement	Total (GW)		Annual Growth Rate %
	2000	2050	
Average load in the summer peak time slice	571	1,249	1.6
Annual peak instantaneous load	702	1,531	1.6
Peak capacity value (not nameplate) to meet reserve margin	875	1,730	1.4

Table B-6 gives the peak reserve margin for each region. Reserve margin is ramped from its initial value in 2000 to the 2010 requirement, and maintained thereafter. It is assumed that energy growth and peak demand grow at the same rate, and that the load shape stays constant from one period to the next.

Table B-6. Peak reserve margin

NERC Region	Abbreviation	2010 Required Reserve Margin
1	ECAR	0.12
2	ERCOT	0.15
3	MAAC	0.15
4	MAIN	0.12
5	MAPP	0.12
6	NY	0.18
7	NE	0.15
8	FL	0.15
9	SERC	0.13
10	SPP	0.12
11	NWP	0.08
12	RA	0.14
13	CNV	0.13

Source: PA Consulting Group (2004)

B.3 Wind

B.3.1 Wind Resource Definition

Table B-7 defines wind power classes.

Table B-7. Classes of wind power density

Wind Power Class	Wind Power Density, W/m^2	Speed, m/s
3	300–400	6.4–7.0
4	400–500	7.0–7.5
5	500–600	7.5–8.0
6	600–800	8.0–8.8
7	>800	>8.8

Notes: W/m^2 = watts per square meter; m/s = meters per second. Wind speed measured at 50 m above ground level.
Source: Elliott and Schwartz (1993)

Wind power density and speed are not explicitly calculated in WinDS. Different classes of wind power are identified by resource level, CF, turbine cost, and so forth, which are discussed in the subsections that follow.

B.3.2 Wind Resource Data

The basic wind resource input for the WinDS model is the amount of available windy land area (in square kilometers [km^2]) by wind power class (Class 3 and higher). The amount of available windy land is derived from state wind resource maps and modified for environmental and land-use exclusions (as outlined in Tables B-8 and B-9). These maps are the most recent available from the Wind Powering America (WPA) initiative (EERE) and individual state programs. The maps depict estimates of the wind resource at 50 m above the ground.

The WinDS base case (Denholm and Short 2006) used only two data sources, the WPA maps validated by NREL and the *Wind Energy Resource Atlas of the United States* (PNL 1987). For this report, however, the WinDS model uses recent wind maps from individual state programs where available (instead of maps from the 1987 PNL atlas) and new WPA state maps.

Using the recent maps offers an advantage in that modern mapping techniques and recent measurement data are incorporated into the mapping process, resulting in a finer horizontal resolution (1 km or smaller size grid cells) of the wind resource. The disadvantage is that not all updated maps were created using the same technique. The difference in techniques leads to a “patchwork quilt” pattern in some regions. The differences also result in notable resource discontinuities at state borders. For this project, several 50 m state maps were adjusted to produce more interstate compatibility. Table B-8 summarizes the state sources and land-use exclusions for the land-based wind resource data used in WinDS, and Table B-9 presents the same information for offshore wind.

Most state maps were completed with direct support from WPA and cost-sharing from individual states and regional partners. Under the WPA initiative, state wind resource maps were produced as described here. The preliminary resource map was produced by AWS Truewind (AWST; Albany, New York). NREL validated this map in cooperation with private consultants who had access to proprietary data, special data, and knowledge of wind resources in each state, or both. The validation results were used to modify the preliminary map and to create a final wind map. NREL mapped three states—Illinois, North Dakota, and South Dakota—before AWST became involved. An important difference between the NREL and AWST maps is that the NREL mapping technique assumed low surface roughness (equivalent to short grasslands); AWST used digital land cover data sets for surface roughness values. Increases in surface roughness generally decreases the estimated 50 m wind resource, so the NREL maps might overestimate the wind resource in areas that do not have low surface roughness. The 50 m wind power classes for individual grid cells on the WPA maps were used to determine available windy land for the WinDS model.

Individual state programs have updated other (non-WPA) maps, which were created using a variety of mapping techniques. NREL has not, however, validated these

Table B-8. Data sources for land-based wind resource and environmental exclusions

Onshore Wind Resource Data Used in WinDS (10/23/2006)

Resource Data (50 m height):

State	Data Source*		State	Data Source*		State	Data Source*
Arizona	2003, N/AWST		Maine	2002, N/AWST		Ohio[a]	2004, N/AWST
Alabama	1987, PNL		Maryland	2003, N/AWST		Oklahoma[a]	2002, OTH
Arkansas	2006, N/AWST**		Massachusetts	2002, N/AWST		Oregon	2002, N/AWST
California	2003, N/AWST		Michigan[a]	2005, N/AWST		Pennsylvania[a]	2003, N/AWST
Colorado	2003, N/AWST		Minnesota	2006, OTH		Rhode Island	2002, N/AWST
Connecticut	2002, N/AWST		Mississippi	1987, PNL		South Carolina	2005, AWST
Delaware	2003, N/AWST		Missouri[a]	2004, N/AWST		South Dakota	2000 NREL
Florida	1987, PNL		Montana	2002, N/AWST		Tennessee	1987, PNL
Georgia	2006, AWST		Nebraska[a]	2005, N/AWST		Texas	2004, OTH/2000, NREL
Idaho	2002, N/AWST		Nevada	2003, N/AWST		Utah	2003, N/AWST
Illinois	2001, NREL		New Hampshire	2002, N/AWST		Vermont	2002, N/AWST
Indiana[a]	2004, N/AWST		New Jersey	2003, N/AWST		Virginia	2003, N/AWST
Iowa	1997, OTH		New Mexico	2003, N/AWST		Washington	2002, N/AWST
Kansas	2004, OTH		New York[a]	2004, AWST		West Virginia	2003, N/AWST
Kentucky	1987, PNL		North Carolina	2003, N/AWST		Wisconsin	2003, OTH
Louisiana	1987, PNL		North Dakota	2000 NREL		Wyoming	2002, N/AWST

* YrSource

Yr = Year produced (1987 to present); Source = PNL, NREL, N/AWST (NREL with AWS TrueWind), AWST (AWS TrueWind alone not validated by NREL) or OTH (data from other sources)

PNL data resolution is 1/4 degree of latitude by 1/3 degree of longitude, each cell has a terrain exposure percent (5% for ridgecrest to 90% for plains) to define base resource area in each cell. Ridgecrest areas have 10% of the area assigned to the next higher power class.

NREL data was generated with the WRAMS model, and does not account for surface roughness. Resolution is 1 km.
Texas includes the Texas mesas study area updated by NREL using WRAMS.

N/AWST data was generated by AWS TrueWind and validated by NREL. Resolution is 400 m for the northwest states (WA, OR, ID, MT, and WY) and 200 m everywhere else. These data consider surface roughness in their estimates.

N/AWST** data was generated by AWS TrueWind, and will be validated by NREL. Data used is preliminary.

OTH data from other sources. The methods, resolution, and assumptions vary. These results have not been validated by NREL
For most states, the data was taken at face value. However, some datasets were not available as 50 m power density. In those cases, assumptions were made to adjust the data to 50 m power density.

[a] In these states, the class 2, 3 and 4 wind power class estimates were adjusted upwards by 1/2 power class to better represent the likely wind resource at wind turbine height. For Nebraska, only the portion of the state east of 102 degrees longitude was adjusted.

Wind Resource Onshore Exclusions (last revised Jan 2004)

Criteria for Defining Available Windy Land (numbered in the order they are applied):

Environmental Criteria	*Data/Comments:*
2) 100% exclusion of National Park Service and Fish and Wildlife Service managed lands	USGS Federal and Indian Lands shapefile, Jan 2005
3) 100% exclusion of federal lands designated as park, wilderness, wilderness study area, national monument, national battlefield, recreation area, national conservation area, wildlife refuge, wildlife area, wild and scenic river or inventoried roadless area.	USGS Federal and Indian Lands shapefile, Jan 2005
4) 100% exclusion of state and private lands equivalent to criteria 2 and 3, where GIS data is available.	State/GAP land stewardship data management status 1, from Conservation Biology Institute Protected Lands database, 2004
8) 50% exclusion of remaining USDA Forest Service (FS) lands (incl. National Grasslands)***	USGS Federal and Indian Lands shapefile, Jan 2005
9) 50% exclusion of remaining Dept. of Defense lands***	USGS Federal and Indian Lands shapefile, Jan 2005
10) 50% exclusion of state forest land, where GIS data is available***	State/GAP land stewardship data management status 2, from Conservation Biology Institute Protected Lands database, 2004
Land Use Criteria	
5) 100% exclusion of airfields, urban, wetland and water areas.	USGS North America Land Use Land Cover (LULC), version 2.0, 1993; ESRI airports and airfields (2003)
11) 50% exclusion of non-ridgecrest forest***	Ridge-crest areas defined using a terrain definition script, overlaid with USGS LULC data screened for the forest categories.
Other Criteria	
1) Exclude areas of slope > 20%	Derived from elevation data used in the wind resource model.
6) 100% exclude 3 km surrounding criteria 2-5 (except water)	Merged datasets and buffer 3 km
7) Exclude resource areas that do not meet a density of 5 km^2 of class 3 or better resource within the surrounding 100 km^2 area.	Focalsum function of class 3+ areas (not applied to 1987 PNL resource data)

***50% exclusions are not cumulative. If an area is non-ridgecrest forest on FS land, it is just excluded at the 50% level one time.

Table B-9. Data sources for offshore wind resource and environmental exclusions

Offshore Wind Resource Data Used in WinDS (10/23/2006)							
Resource Data (50 m height):							
State	Data Source*		State	Data Source*		State	Data Source*
Alabama	2006, NREL3		Maine	2002, NREL1		North Carolina	2003, NREL1
California	2003, NREL1		Maryland	2003, NREL1		Ohio	2006, NREL2
Connecticut	2002, NREL1		Massachusetts	2003, NREL1		Oregon	2002, NREL1
Delaware	2003, NREL1		Michigan	2006, NREL2		Pennsylvania	2006, NREL2
Florida	2006, NREL3		Minnesota	2006, NREL2		Rhode Island	2002, NREL1
Georgia	2006, NREL3		Mississippi	2006, NREL3		South Carolina	2006, NREL3
Illinois	2006, NREL2		New Hampshire	2002, NREL1		Texas	2006, NREL3
Indiana	2006, NREL2		New Jersey	2003, NREL1		Virginia	2003, NREL1
Louisiana	2006, NREL3		New York	2003, NREL1		Washington	2002, NREL1
						Wisconsin	2006, NREL2
* YrSource							
Yr = Year produced (2002 to present); Source = NREL with different methods enumerated below							
NREL1: Validated near-shore data was supplemented with offshore resource data from earlier, preliminary runs which extended further from shore. In most cases, this still did not fill the modeling area of interest of 50 nm from shore. The resource estimates were extended linearly to obtain full coverage at 50 nm with little or no change in spatial pattern.							
NREL2: Similar to NREL1, but available resource data estimates and areas not covered by validated and preliminary data were evaluated by NREL meteorologist to establish a best estimate of resource distribution based on expert knowledge and available measured/modeled data sources.							
NREL3: No validated resource estimates existed to provide a baseline. NREL meteorologists generated an initial best estimate of resource distribution to be used in the model, based on expert knowledge and available measured/modeled data sources.							
Wind Resource Offshore Exclusions							
No exclusions were applied to the offshore resource data. It is characterized by power class and depth (0-30 m and >30m)							

maps, which do not necessarily show the 50 m wind power classes on the maps or the 50 m classes in geographic information system (GIS) format. For two states (Minnesota and Wisconsin) where the 50 m power classes for individual grid cells were unavailable, a methodology that applies basic assumptions to calculate wind power classes for each grid cell was used. This methodology calculates a combination of wind speed at the grid cells (direct or interpolated), extrapolates to adjust the wind speeds from map height(s) to 50 m, plots common wind speed frequency distribution, and takes air density into consideration. Next, environmental and land-use exclusions were applied to arrive at the final windy land area totals.

Updated wind resource maps were unavailable for six southeastern states—Alabama, Florida, Kentucky, Louisiana, Mississippi, and Tennessee. The underlying 50 m wind power class data from the maps contained in the 1987 atlas (PNL 1987) were used to calculate windy land area for these states. The horizontal resolution of the atlas maps is quite a bit larger (approximately 25 km grid cells) than that of the updated state maps, which feature 1 km or smaller grid cells. To compensate for the low resolution, landform classifications and environmental and land use exclusions were used to calculate the available windy land for these states.

As mentioned previously, several state maps were adjusted to produce more interstate compatibility. The Texas map was adjusted to include wind resources currently being developed on the mesas in western Texas. Because the mesas are relatively small terrain features, adequately depicting the available resources on these features is difficult. As a result, the Texas map underestimates the power class on the mesas where considerable wind energy development has taken place. In adjusting the maps, the power class values for the mesas were increased based on anemometer measurements, leading to a more realistic representation of the wind energy available. The maps for eight states—Oklahoma, Missouri, Nebraska (the eastern two-thirds of the state), Indiana, Michigan, Ohio, Pennsylvania, and New York—were adjusted because their 50 m wind power class maps underestimate the potential resource at modern turbine hub heights. The available resource increase results from the high wind speed shear that is present in these states. The available windy land in these states was increased based on the wind power density values of individual grid cells. Grid cells in classes 2, 3, and 4 that had 50 m power density values greater than the midpoint of the associated wind power class were adjusted to the next highest class. The these adjustments increased the estimated amount of land with class 3, 4, and 5 wind resources.

For each of the 358 WinDS regions, the total available land area corresponding to a particular wind resource power class was multiplied by an assumed turbine density of 5 megawatts per square kilometer (MW/km^2). This calculation yields the total wind-generation capacity available within each WinDS region for each wind power class.

The patchwork quilt effect that results from the varied resource input data affects the selection of wind energy capacity in the WinDS model. If a state's resource is underestimated, the WinDS model may select less wind energy capacity than is currently being developed in a given state. Similarly, if a state's resource is overestimated, the actual wind energy capacity could be significantly less than that calculated by the model.

All these resource maps were based on wind power estimates at 50 m above ground level. Today's wind turbines, however, have hub heights as high as 80 m to 100 m. As turbine technology improves and hub heights increase, wind resources could be significantly different. Many states that show poor wind capability for electricity generation at the 50 m level may have significantly improved wind speeds at heights of 80 m to 100 m. As an example, even though Missouri is currently developing several hundred megawatts of wind energy, WinDS does not specify significant wind energy capacity for the state.

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B.3.3 WinDS Seasonal and Diurnal Capacity Factor Calculations

For each region and wind power class (classes 3 to 7), 16 time slices represent four seasons and four time periods (see Table B-3). The diurnal and seasonal variations of the wind are portrayed as the ratio of the average wind turbine output during the time slice with the annual average wind turbine output. Average CFs are calculated for each of the 358 WinDS regions for each power class.

Monthly and hourly wind variations were obtained from two databases:

- AWST text supplemental database files
- National Commission on Energy Policy/National Center for Atmospheric Research (NCEP/NCAR) global reanalysis mean values (Kalnay et al. 1996).

For states with AWST data, annual and monthly average wind speeds and power were selected from the fine map grid (400 m resolution in Washington, Oregon, Idaho, Montana, and Wyoming; 200 m resolution in all other states), and hourly wind speed profiles by season from the coarse map grid (10 km in Washington, Oregon, Idaho, Montana, and Wyoming; 2 km in all other states). States with AWST data are identified in Table B-8.

For monthly input data, only one 3 × 3 km cell for each region and power class was used. This cell was chosen because it has the lowest cost, based on the existing grid usage optimization that is normally done as an input to WinDS (Sabeff et al. 2004). The resulting monthly pattern is the average of the monthly values within the 3 × 3 km cell for all map points in the desired power class (plus or minus one class). For hourly input data, the closest grid point from the coarse grid for each 3 × 3 km cell was used. The hourly pattern is the average of hourly values for up to twenty 3 × 3 km cells for each region/power class combination. There are four patterns, one for each season. Seasons are three-month periods (March–May, June–August, September–November, and December–February).

For states without AWST data and for certain offshore regions, NCEP/NCAR reanalysis data were used. Reanalysis uses a dynamic data assimilation model to create worldwide data sets of wind, temperature, and other variables on a 208 km resolution grid, four times daily, throughout the depth of the atmosphere. Average values of wind speed, wind power, and air density were used, by month and by day (four times daily), over a 46-year period of record. Reanalysis wind characteristics from 120 m above ground level have been found to have the best correlation with measured wind data and wind maps. Reanalysis data, however, is suitable for use only over fairly level terrain at lower elevations. Fortunately, AWST data is available for most states that are not suitable for reanalysis.

For regions that use reanalysis, the reanalysis grid point closest to the geographic center of the region was chosen. For some offshore locations, the center of the offshore region was computed and the closest reanalysis grid point was used.

Using the AWST and NCEP/NCAR databases, input data sources were used to populate matrices of average wind speed, wind power, and air density by month and hour of day (24 hours × 12 months). The 24 × 12 array of wind speed, wind power, and air density was then divided into desired seasonal and diurnal time slices (see Table B-3). For each time slice, the power output of the General Electric International (GE) 1.5 MW wind turbine as a function of air density was estimated, and a histogram of wind speed probability as a function of wind speed and Weibull *k* factor was calculated.

The data was then combined to calculate the wind turbine CF for each time slice. In the AWST data, wind power is available only by month, so the Weibull *k* factor was calculated only once for each season. All times of day use the same Weibull *k* for calculating CF. Finally, a weighted average of CFs from the four time slices was used to revise nighttime values into a "nights and weekends" capacity factor. Time-slice CFs were then normalized by the total annual CF, resulting in values representing the ratio of power produced in the current time slice to annual average power produced. This is the desired input into the WinDS model.

This process creates a desired array of CF ratios only for regions and wind power classes with data. With reanalysis, each region has data from only one power class. A final data processing step is to populate the entire array of 358 regions × 5 power classes with results. If a power class is missing, data from the next-lower power class are chosen. If there are no available data from a lower power class, the next-higher power class is chosen. For reanalysis regions, all five power classes are given the same array of CF ratios.

B.3.4 Wind Technology Cost and Performance

Black & Veatch analysts (in consultation with AWEA industry experts) developed wind technology cost and performance projections for this report (Black & Veatch, forthcoming 2008). Costs for turbines, towers, foundations, installation, profit, and interconnection fees are included. Capital costs are based on an average installed capital cost of $1,775 per kilowatt (kW) in 2007. After adjusting for inflation and removing the construction financing charge, this reduces to $1,650/kW for 2006. Additional costs reflecting terrain slope and regional population density are described later in this subsection.

Technology development is projected to reduce future capital costs by 10%.Black & Veatch used historical capacity factor data to create a logarithmic best-fit line, which is then applied to each wind power class to project future performance improvements.[17] Black & Veatch's experience indicate that variable and fixed operations and maintenance (O&M) costs represent an average of recent project costs. Approximately 50% of variable O&M cost is the turbine warranty. These costs are expected to decline as turbine reliability improves and the scale of wind turbines increases. Other variable O&M expenses are tied to labor rates, royalties, and other costs that are expected to be stable. Fixed O&M costs, including insurance, property taxes, site maintenance, and legal fees, are projected to stay the same because they are not affected by technology improvements. Table B-10 lists cost and performance projections for land-based wind systems (Black & Veatch 2007).

Table B-11 lists cost and performance projections prepared by Black & Veatch for shallow offshore wind technology (in water shallower than 30 m). Capital costs for 2005 were based on publicly available cost data for European offshore wind farms. Capital costs are assumed to decline 12.5% as a result of technology development and a maturing market. The capacity factor projection, which is based on the logarithmic best-fit lines generated for land-based turbines, we increased 15% to account for larger rotor diameters and reduced wind turbulence over the ocean. By 2030 this adjustment factor is reduced to 5% as land-based development allows larger turbines to be used in turbulent environments. O&M costs are assumed to be three times those of land-based turbines (Musial and Butterfield 2004) with a learning rate commensurate to that projected by the U.S. Department of Energy (DOE; NREL 2006).

A number of adjustments, including financing, interest during construction, terrain slope, population density, and rapid growth were applied to the capital cost. Although financing has not been treated explicitly, it is assumed to be captured by the weighted cost of capital (real discount rate) of 8.5%.

A slope penalty that increases one-fourth of the capital cost by 2.5% per degree of terrain slope was used to represent expected costs associated with installations on mesas or ridge crests. Costs associated with installation represent 25% of the capital cost. Wiser and Bolinger (2007) present regional variations in installed capital cost for projects constructed in 2006. Applying a multiplier related to population density within each of the WinDS regions results in regional variations similar to the observed data. An additional 20% must be applied to the base capital cost in New

[17]Capacity factors for 2000 and 2005 fit to actual data. For the higher wind power classes (6 and 7), however, limited data are available for operating plants, so capacity factors were extrapolated from the linear relationships between wind classes.

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Table B-10. Land-based wind technology cost and performance projections (US$2006)

Wind Resource Power Class at 50 m	Year Installed	Capacity Factor (%)	Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
3	2005	32	1,650	11.5	7.0
3	2010	35	1,650	11.5	5.5
3	2015	36	1,610	11.5	5.0
3	2020	38	1,570	11.5	4.6
3	2025	38	1,530	11.5	4.5
3	2030	38	1,480	11.5	4.4
4	2005	36	1,650	11.5	7.0
4	2010	39	1,650	11.5	5.5
4	2015	41	1,610	11.5	5.0
4	2020	42	1,570	11.5	4.6
4	2025	43	1,530	11.5	4.5
4	2030	43	1,480	11.5	4.4
5	2005	40	1,650	11.5	7.0
5	2010	43	1,650	11.5	5.5
5	2015	44	1,610	11.5	5.0
5	2020	45	1,570	11.5	4.6
5	2025	46	1,530	11.5	4.5
5	2030	46	1,480	11.5	4.4
6	2005	44	1,650	11.5	7.0
6	2010	46	1,650	11.5	5.5
6	2015	47	1,610	11.5	5.0
6	2020	48	1,570	11.5	4.6
6	2025	49	1,530	11.5	4.5
6	2030	49	1,480	11.5	4.4
7	2005	47	1,650	11.5	7.0
7	2010	50	1,650	11.5	5.5
7	2015	51	1,610	11.5	5.0
7	2020	52	1,570	11.5	4.6
7	2025	52	1,530	11.5	4.5
7	2030	53	1,480	11.5	4.4

Note: MWh = megawatt-hour
Source: Black & Veatch (2007)

England to reflect observed capital cost variations. Slope and population density penalties have been applied to the capital cost listed in Tables B-10 and B-11 within the model to represent topographical and regional variations across the United States.

If the demand for new wind capacity significantly exceeds the amount supplied in the previous year, WinDS assumes that the price paid per unit of wind capacity can rise above the capital costs of Tables B-10 and B-11 as well as the multiplier factors**.**. In particular, installing more than 20% new wind generation over the preceding year, will increase capital costs by 1% for each 1% growth above 20% per year (EIA 2004).

Table B-11. Shallow offshore wind technology cost and performance projections (US$2006)

Wind Resource Power Class at 50 m	Year Installed	Capacity Factor (%)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
3	2005	34	2,400	15	21
3	2010	37	2,300	15	18
3	2015	38	2,200	15	16
3	2020	39	2,150	15	14
3	2025	40	2,130	15	13
3	2030	40	2,100	15	11
4	2005	38	2,400	15	21
4	2010	41	2,300	15	18
4	2015	43	2,200	15	16
4	2020	44	2,150	15	14
4	2025	45	2,130	15	13
4	2030	45	2,100	15	11
5	2005	42	2,400	15	21
5	2010	45	2,300	15	18
5	2015	46	2,200	15	16
5	2020	47	2,150	15	14
5	2025	48	2,130	15	13
5	2030	48	2,100	15	11
6	2005	46	2,400	15	21
6	2010	48	2,300	15	18
6	2015	50	2,200	15	16
6	2020	51	2,150	15	14
6	2025	51	2,130	15	13
6	2030	51	2,100	15	11
7	2005	50	2,400	15	21
7	2010	52	2,300	15	18
7	2015	54	2,200	15	16
7	2020	55	2,150	15	14
7	2025	55	2,130	15	13
7	2030	55	2,100	15	11

Source: Black & Veatch (2007)

B.4 Conventional Generation

U.S. conventional energy generation included in the WinDS model, and most likely to be built in the United States, has been included in EIA's data reports (2007). Table B-12 illustrates expected construction time and schedules for conventional energy technologies.

WinDS considers outage rates when determining the net capacity available for energy (as described in Section 2), and also when determining the capacity value of each technology. Planned outages are assumed to occur in all seasons except summer. Table B-12 shows outage rates for each conventional technology.

Table B-12. General assumptions for conventional generation technologies

Technology Modeled	Capability for new builds in WinDS	Construction Time (years) (1)	Construction Schedule (2) Fraction of Cost in Each Year						Forced Outage Rate (%) (3)	Planned Outage Rate (%) (3)	Emissions Rates (4) (lbs/MMBTU fuel input)				Lifetime (years)
			1	2	3	4	5	6			SO_2	NO_x	Hg	CO_2	
Conventional Hydropower - Hydraulic Turbine	No	NA	-	-	-	-	-	-	2.0%	5.0%	0	0	0	0	100
Natural Gas Combustion Turbine	Yes	3	0.8	0.1	0.1	-	-	-	10.7%	6.4%	0.0006	0.08	0	33.2877	30
Combined Cycle Natural Gas Turbine	Yes	3	0.5	0.4	0.1	-	-	-	5.0%	7.0%	0.0006	0.02	0	33.2877	30
Conventional Pulverized Coal Steam Plant (No SO_2 Scrubber)	No-Scrubbers may be added to meet SO_2 constraints. Existing plants may also switch to low-sulfur coal.	6	0.1	0.2	0.2	0.2	0.2	0.1	7.9%	9.8%	0.2355	0.448	4.6E-06	55.77131	60
Conventional Pulverized Coal Steam Plant (With SO_2 scrubber)	No-see above	6	0.1	0.2	0.2	0.2	0.2	0.1	7.9%	9.8%	1.57	0.448	4.6E-06	55.77131	60
Advanced Supercritical Coal Steam Plant (with SO_2 and No_x Controls)	Yes	4	0.4	0.3	0.2	0.1	-	-	7.9%	9.8%	0.157	0.02	4.6E-06	55.77131	60
Integrated Coal Gasification Combined Cycle Turbine	Yes	4	0.4	0.3	0.2	0.1	-	-	7.9%	9.8%	0.0184	0.02	4.6E-06	55.77131	60
Oil/Gas Steam Turbine	No -Assumes Gas-CT or Gas-CC will be built instead.	NA	-	-	-	-	-	-	7.9%	9.8%	0.026	0.1	0	33.2877	50
Nuclear	Yes	6	0.1	0.2	0.2	0.2	0.2	0.1	5.0%	5.0%	0	0	0	0	30
Geothermal	No	NA	-	-	-	-	-	-	5.0%	5.0%	0	0	0	0	20
Biomass (as Thermal Steam Generator)	No	NA	-	-	-	-	-	-	5.0%	5.0%	0	0	0	0	45
Concentrating Solar Power with Storage	Yes	3	0.5	0.4	0.1	-	-	-	35.0%	5.0%	0.00015	0.02	0	8.321926	30
Municipal Solid Waste / Landfill Gas	No	NA	-	-	-	-	-	-	5.0%	5.0%	0	0	0	0	30

Emission rates are estimated in Table B-12 for SO_2, NO_x, mercury, and CO_2 and provides input-specific emission rates (in pounds per million British thermal units) for plants that use combustible fuel. Output emission rates (in pounds per megawatt-hour) are calculated by multiplying input emission rate by heat rate.

B.4.1 Conventional Generation Cost and Performance

Table B-13 also gives capital cost values, heat rates (efficiency), and fixed and variable O&M costs for conventional technologies that might be added to the electric system. Cost and performance values for natural gas, nuclear, and coal technologies are based on recent project costs according to Black & Veatch experience. Pulverized coal plants continue to operate in WinDS, and SO_2 scrubbers can be added to unscrubbed coal plants for $200/kW. Oil, gas, steam, and unscrubbed coal plants cannot be added to the electric system, but those currently in operation are maintained until retired. WinDS sites conventional generation technology where it is least expensive (generally adjacent to load centers) and does not require new transmission. California is the exception because its legislative requirements prohibit siting new coal plants.

Capital costs for 2005, 2010, and 2015 are based on proposed engineering, procurement, and construction (EPC) estimates for plants that will be commissioned in 2010, 2015, and 2020. A wet scrubber is included in the EPC costs for new pulverized coal plants. Owners' costs of 20% for coal, nuclear, and combined-cycle gas plants and 10% for simple-cycle gas plants provide an "all-in" cost. These owners' costs are based on national averages and include transmission and interconnection, land, permitting, and other costs. As with wind systems, an additional 20% of the capital costs listed in Table B-13 is applied to coal and nuclear generation technology in New England, representing siting difficulties.

B.4.2 Fuel Prices

Fuel prices for natural gas and coal are derived from reference projections from the AEO (EIA 2007b). These tables provide the prices in each census region, which are then assigned to a NERC subregion in WinDS. Prices in the AEO are projected to 2030. Beyond 2030, WinDS projects that fuel prices will increase at the same national annual average rate as the AEO's 2030 projection.

Figure B-4 illustrates the projected fossil fuel prices in constant $US2005. The 20% Wind Scenario uses the reference AEO fuel price forecast for coal because government agencies and the private sector regularly use that forecast to make planning and investment decisions. The New York Mercantile Exchange futures prices for natural gas for May 2007 through 2012 exceed the AEO's high fuel price forecast over that period. Also, under the current set of technology cost and performance assumptions, the WinDS model tends to select natural gas-fueled technology over coal-fueled technology. To provide a conservative estimate while representing a more traditional mix of conventional generation technology, the AEO high natural gas price forecast has been implemented.

The price of uranium fuel in WinDS is constant at $0.5/MMBtu (Denholm and Short 2006).

Table B-13. Cost and performance characteristics for conventional generation (US$2006)

	Install Date	Capital Cost ($/kW)	Fixed O&M ($/MW/yr)	Variable O&M ($/MWh)	Heat Rate (Btu/kWh)
Gas CT	2005	625	7,700	12.0	11,560
	2010	750	6,600	2.8	8,900
	2015	750	6,600	2.8	8,900
	2020	750	6,600	2.8	8,900
	2030	750	6,600	2.8	8,900
Gas-CC	2005	780	14,400	3.0	6,870
	2010	780	14,400	3.0	6,870
	2015	780	14,400	3.0	6,870
	2020	780	14,400	3.0	6,870
	2030	780	14,400	3.0	6,870
New Coal (SC)	2005	2,120	35,300	1.7	9,470
	2010	2,180	35,300	1.7	9,200
	2015	2,240	35,300	1.7	9,100
	2020	2,240	35,300	1.7	9,000
	2030	2,240	35,300	1.7	9,000
Coal - IGCC	2005	2,750	38,100	3.9	9,000
	2010	2,840	38,100	3.9	9,000
	2015	2,840	38,100	3.9	8,900
	2020	2,840	38,100	3.9	8,800
	2030	2,840	38,100	3.9	8,580
Nuclear	2005	3,260	90,000	0.5	10,400
	2010	3,170	90,000	0.5	10,400
	2015	3,020	90,000	0.5	10,400
	2020	2,940	90,000	0.5	10,400
	2030	2,350	90,000	0.5	10,400

Notes: New nuclear plants may not be constructed before 2010. O&M costs do not include fuel. Heat rate is net heat rate (including internal plant loads).

Source: Black & Veatch 2007

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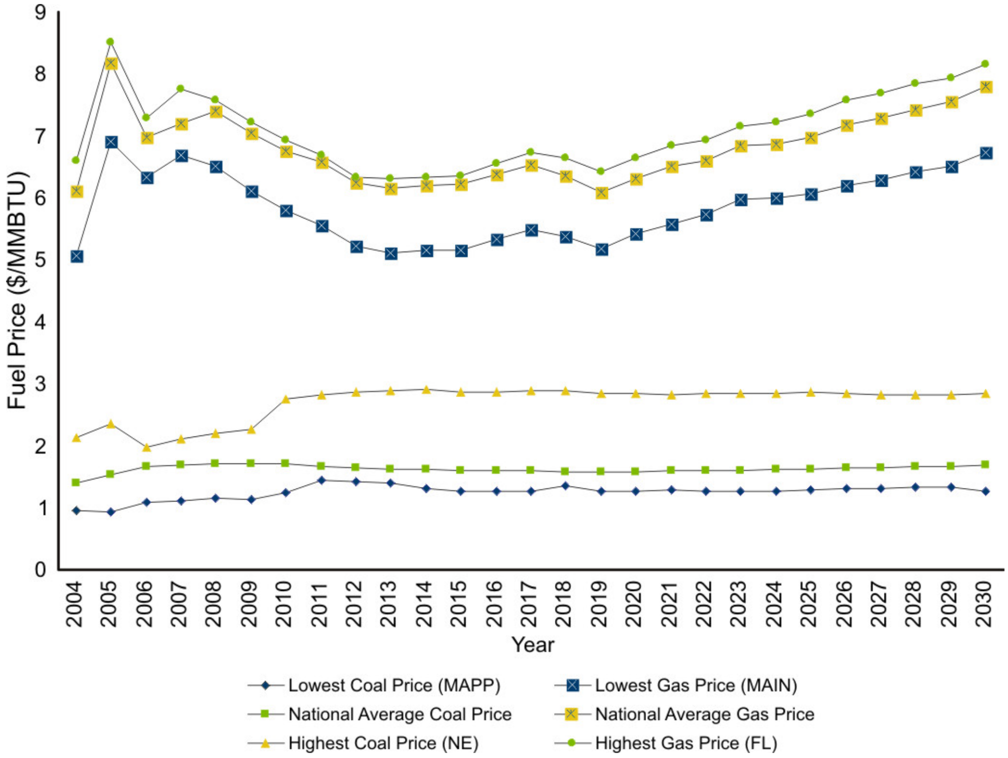
Figure B-4. Projected coal and natural gas prices in WinDS to 2030



B.5 Transmission

Three types of transmission systems can be used to transport wind power around the country:

- **Existing grid:** It is assumed that 10% of the existing grid can be used for new wind capacity, either by improving the grid or by tapping existing unused capacity. A GIS optimization determines the distance at which a particular wind farm will have to be built to connect to the grid (based on the assumption that the closest wind installation will access the grid first at the least cost). In this way, a supply curve of costs to access the grid is created for each class of wind in each region. Additionally, the model assumes a pancake-type fee may be charged for crossing between balancing areas . The supply curves described earlier are based on this type of transmission and the GIS optimization described here. In the near term, one can expect that most wind will be built and will use the existing grid without needing to build excessive amounts of new transmission lines, but as higher penetration levels are reached, the existing grid will be insufficient.

  Existing transmission capacity is estimated using a database of existing lines (length and voltage) from RDI/Platts (Platts Energy Market Data; see http://www.platts.com). This database is translated into a megawatt capacity as a function of kilovolt (kV) rating and length (Weiss and Spiewak 1998).

- **New lines:** The model has the ability to build straight-line transmission lines between any of the 358 wind regions. The line is built exactly to the size necessary to transmit the desired megawatts and the cost of building that transmission line is accounted for in the model.

  AWEA experts indicate that new transmission line capacity might be constructed for any generation technology for an average cost of $1,600/MW-mile. Based on input from the AWEA expert panel, regional transmission cost variations include an additional 40% in New England and New York; 30% in PJM East (New Jersey and Delaware); 20% in PJM West (Maryland, West Virginia, Pennsylvania, Ohio, parts of Illinois, Indiana, and Virginia); and 20% in California.

  The WinDS model assumes that 50% of the cost of new transmission is borne by the generation technology for which the new transmission is being built (wind or conventional); the other half is borne by the ratepayers within a region (because of the reliability benefits to all users associated with new transmission). This 50–50 allocation, which is common in the industry, was recently adopted for the 15-state Midwest Independent Transmission System Operator (Midwest ISO) region. New wind transmission lines that carry power across the main interconnects are not cost-shared with other technology. In the WinDS model, this sharing of costs is implied by reducing the cost of new transmission associated with a particular capacity by 50%. This means that the relative costs of transmission and capacity capital are in line with the model's assumption. The remaining 50% of transmission costs are integrated into the final cost value outputs from the model, resulting in accurate total transmission costs.

- **In-region transmission:** Within any of the 358 wind regions, the model can build directly from a wind resource location to a load within the same region. A second GIS-generated supply curve is used within the model to assign a cost for this transmission.

A fourth type of transmission, used predominantly by conventional capacity and called general transmission, can be built as well. This is limited because conventional capacity can generally be built in the region where it is needed, thereby obviating the need for new transmission.

WinDS uses a transmission loss rate of 0.236 kW/MW-mile. This value is based on the loss estimates for a typical transmission circuit (Weiss and Spiewak 1998). The assumed typical line is a 200-mile, 230-kV line rated at 170 megavolt amperes (MVA; line characteristics derived from EPRI [1983]).

To emulate large regional planning structures based on that of the Midwest ISO, there is essentially no wheeling fee between balancing areas used in this analysis (although the model has the capability to model such a fee). The wind penetration is limited to 25% energy in each of the three interconnects: Western, Eastern, and ERCOT.

B.6 Treatment of Resource Variability

The variability of wind resources can impact the electrical grid in several ways. One useful way to examine these impacts is to categorize them in terms of time, ranging from multiyear planning issues to small instantaneous fluctuations in output.

At the longest time interval, a utility's capacity expansion plans might call for the construction of more nameplate generation capacity. To meet this need, planners can plan to build conventional dispatchable capacity or wind. The variability of wind output precludes the planners from considering 1 MW of nameplate wind capacity to be the same as 1 MW of nameplate dispatchable capacity. The wind capacity cannot be counted on to be available when electricity demand is at its peak. Actually, conventional capacity cannot be considered 100% available, either. The difference is in the degree of availability. Conventional generators are available 80% to 98% of the time. However, wind energy is available at varying levels that average about 30% to 45% of the time, depending on the quality of the wind site. For planning purposes, this lack of availability can be handled in the same way—a statistical treatment that calculates how much more load can be added to the system for each megawatt of additional nameplate wind or conventional capacity or effective load carrying capability (ELCC).

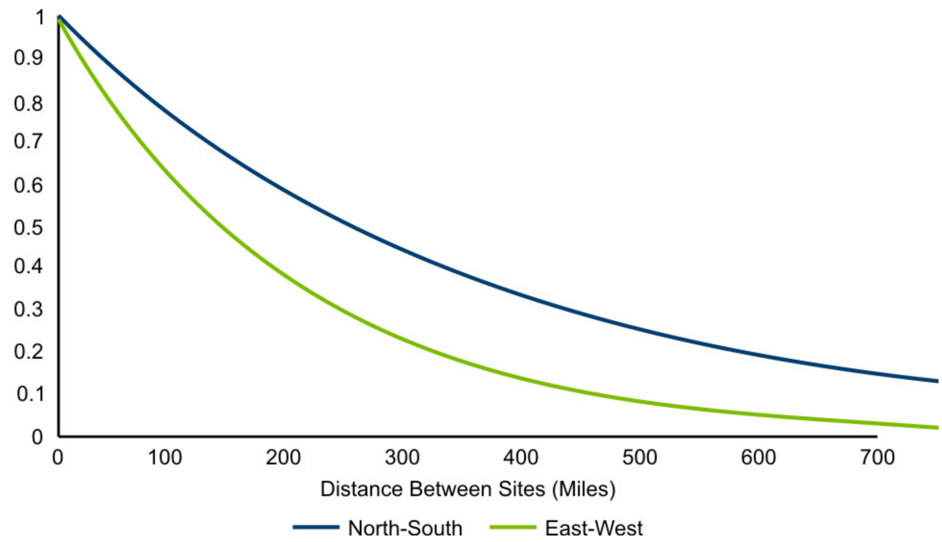
Wind's ELCC is less than that of conventional capacity because (1) the wind availability is less conventional fuel availability and (2) at any given instant, energy output from a new wind farm can be heavily correlated with the output from existing wind farms. In other words, if the wind is not blowing at one wind site, there is a reasonable chance that it is not blowing at another nearby site. On the other hand, there is essentially no correlation between the outputs of any two conventional generation plants.

Fortunately, there are ways to partly mitigate both the low availability of the wind resource and its correlation between sites. In the past 20 years, the capacity factors of new wind installations have improved considerably. This is attributable to better site exploration and characterization and to improvements in the wind turbines (largely higher towers).

The correlation in wind output between sites can also be reduced. Increasing the distance between sites and the terrain features that separate them reduces the chance that two sites will experience the same wind at the same time. Figure B-5 shows this correlation as a function of distance between sites in an east–west direction and in a north–south direction (Simonsen and Stevens 2004). With its multiple regions, WinDS is able to approximate the distance between sites and, therefore, the correlation between their outputs. WinDS uses the correlation between sites to estimate the variation in wind output from the total set of wind farms supplying power to a particular region.

Between each two-year optimization period and for each demand region, WinDS updates its estimate of the marginal ELCC associated with adding wind of each resource class in each wind supply region to meet demand within a NERC region. This marginal ELCC is a strong function of the wind capacity factor and the distance from the existing wind systems to the new wind site. It is also a weak function of the demand region's LDC and the size and forced outage rates of conventional capacity. This marginal ELCC is assumed to be the capacity value of each megawatt of that

Figure B-5. Distance between wind sites and correlation with power output



wind class added in the next period in that wind supply region to serve the NERC region's demand.

All other factors being equal, when expanding wind capacity, WinDS will select the next site in a region that is as far from the existing sites as possible to ensure the lowest correlation and the highest ELCC for the next wind site. (From a practical standpoint, all factors are never "equal," and WinDS considers the trade-offs between ELCC and wind site quality, transmission availability and cost, and local siting costs.)

Generally, for the first wind site supplying a demand region, these capacity values (ELCCs) are almost equal to the peak season capacity factor. As the wind penetrates to higher levels, though, the ELCC can decline to almost zero in an individual wind supply region.

The next time frame of major interest is the day ahead. Utilities generally make decisions on which generating units to commit to generation the day before they are actually committed. To comply with these unit-commitment procedures, independent power plant owners can be expected to bid for firm capacity a day ahead. This can be problematic for wind generator owners. For example, if the wind owner bids to provide firm capacity and the wind does not blow as forecast, the owner may have to make up the difference by purchasing power on the real-time market. If the purchased power costs more per kilowatt-hour than the owner is being paid for the day-ahead bid, the owner will lose money.

Not all of today's electric grid systems operate day-ahead and real-time markets. California, for example, allows a monthly balancing of bid and actual wind generation that is much more tolerant of the inaccuracies in forecasting wind a day ahead of time. In all cases, however, the imbalances can be offset with adequate operating reserves. To capture the essence of the unit-commitment issue, WinDS estimates the impact of wind variability on the need for operating reserves (which include quick-start and spinning reserves) that can rapidly respond to changes in wind output. The operating reserves are assumed to be a linear function of the variance in the sum of generation (both wind and conventional) minus load. Because the variability of wind is statistically independent of load variability and forced outages, the total variance can be calculated as the sum of the variance associated with the normal (i.e., no wind) operating reserve and the total variance (over all the wind supply regions) in the wind output over the reconciliation period.

Before each two-year optimization, WinDS calculates the marginal operating reserve additions required by the next unit of wind added in a particular wind supply region from a particular wind class. The resulting value is the difference between the operating reserve required by the total system with the new wind and the operating reserve required by the total system if there were no new wind installations in that region. This value is then used throughout the next two-year linear program optimization as the marginal operating reserve requirement induced by the next megawatt of wind addition in that region of that wind resource class.

In the shortest time interval, regulation reserves must compensate for instantaneous changes in wind output. Regulation reserves are normally provided by automatic generation control of conventional generators whose output can be automatically adjusted to compensate for small voltage changes on the grid. Fortunately, these instantaneous changes in wind output do not all occur at the same time, even from wind turbines within the same wind farm. This lack of correlation over time and the ease with which conventional generators can respond allows this second-order cost to be reasonably ignored.

WinDS assumes that the wind generated energy delivered to a specific demand region in a specific time slice in excess of the total load for that region/time slice will be lost. In addition, WinDS also statistically accounts for surplus wind lost within a time slice because of variations in load and wind within the time slice.

WinDS includes three options for mitigating the impact of resource variability. The first option is to add conventional generators that can provide spinning reserve (e.g., gas-CC) and quick-start capabilities (combustion turbines). The second, and usually least costly, option is to allow the dispersion of new wind installations to reduce the correlation of the outputs from different wind sites. Finally, the model can allow for storage of electricity at the wind site, which is usually the most costly option. The storage option was not available within this analysis and is currently being developed for the model.

B

B.7 Federal and State Energy Policy

The WinDS accounts for all currently enacted federal and state emission standards, renewable portfolio standards (RPS), and tax credits.

B.7.1 Federal Emission Standards

WinDS provides the ability to add a national cap on **CO_2** emissions from electricity production. WinDS can also account for a tax for CO_2 emissions. However, neither a carbon cap nor a tax is implemented in the 20% Wind Scenario.

Emissions of **SO_2** are capped at the national level. WinDS uses a cap that corresponds roughly to the 2005 Clean Air Interstate Rule (CAIR), replacing the previous limits established by the 1990 Clean Air Act Amendments (CAAA). The CAIR rule divides the United States into two regions. WinDS uses the U.S. Environmental Protection Agency's (EPA) estimate of the effective national cap on

SO_2 resulting from the CAIR rule (EPA 2005). Table B-14 shows the SO_2 cap used in WinDS.

Table B-14. National SO_2 emission limit schedule in WinDS

Year	2003	2010	2015	2020	2030
National SO_2 Emissions (Million Tons)	10.6	6.1	5.0	4.3	3.5

(EPA 2005)

WinDS currently allows unrestrained **NO_x** emissions. . The NO_x cap from CAIR can be added, but the net effect on the overall competitiveness of coal is expected to be relatively small (EIA 2003).

WinDS currently allows unrestrained **Mercury** emissions. The Clean Air Mercury Rule (see http://www.epa.gov/camr/index.htm) is a cap and trade regulation, which is expected to be met largely by the CAIR requirements. Control technologies for SO_2 and NO_x that are required for CAIR are expected to capture enough mercury to largely meet the cap goals. As a result, the incremental cost of mercury regulations is very low and is not modeled in WinDS (EIA 2003).

B.7.2 Federal Energy Incentives

Several classes of incentives have been applied to wind systems at the federal level. These incentives generally have the effect of reducing the cost of producing energy from renewable sources. A production tax credit (PTC) offsets the tax liability of companies based on the amount of energy produced. This analysis assumes that the current PTC will be available for wind through 2008 (see Table B-15).

Table B-15. Federal renewable energy incentives

Name	Value	Notes and Source
Renewable Energy PTC	$19/MWh	Applies to wind. No limit to the aggregated amount of incentive. Value is adjusted for inflation to US$2006. Expires end of 2008.

(U.S. Congress 2005)

B.7.3 State Energy Incentives

Several states also offer production and investment incentives for renewable energy resource development. Table B-16 lists the values used in WinDS. However, in the 20% Wind Scenario these incentives are overwhelmed by the specification of wind energy generation in each year through 2030.

Table B-16. State renewable energy incentives

State	PTC $/ MWh	ITC	Assumed State Corporate Tax Rate
Iowa		5.00%	10.0%
Idaho		5.00%	7.60%
Minnesota		6.50%	9.8%
New Jersey		6.00%	9.0%
New Mexico	10		7.0%
Oklahoma	2.5		6.0%
Utah		4.75%	5.0%
Washington		6.50%	0.0%
Wyoming		4.00%	0.0%

Investment and production tax credit data from IREC 2006
Tax rates from: www.taxadmin.org/fta/rate/corp_inc.html

B.7.4 State Renewable Portfolio Standards

A number of states have developed Renewable Portfolio Standards (RPS), and states can put capacity mandates in place as an alternative or supplement to an RPS (see Table B-17). A capacity mandate requires a utility to install a certain fixed capacity of renewable energy generation. Unless prohibited by law, a state might also meet requirements by importing electricity.

Table B-17. State RPS requirements as of August 2005

State	RPS Start Year[2]	RPS Full Imple-mentation[3]	Penalty in $/MWh	WinDS Assumed RPS Fraction[4]	Legislated RPS Fraction (%)	Load Fraction[5]
Arizona	2001	2025	50	0.0079	1.1	1
California	2003	2017	5	0.034	20	0.63
Colorado	2007	2015	50	0.044	10	0.69
Connecticut	2004	2010	55	0.013	10	0.94
Delaware	2007	2019	25	0.056	10	0.75
Illinois	2004	2013	10	0.062	15	0.92
Massachusetts	2003	2009	50	0.026	4	0.85
Maryland	2006	2019	20	0.045	7.5	0.8
Minnesota	2002	2015	10	0.072	1,125 MW	1
Montana	2008	2015	10	0.075	15	0.9
New Jersey	2005	2008	50	0.029	6.5	1
New Mexico	2006	2011	10	0.026	10	0.53
Nevada	2003	2015	10	0.133	20	0.89
New York	2006	2013	5	0.035	25	0.84
Oklahoma	2005	2016	50	0.05	See Note 6	1
Oregon	2002	2020	5	0.078	See Note 6	1
Pennsylvania	2007	2020	45	0.014	8	0.98
Rhode Island	2007	2019	55	0.069	15	0.99
Texas	2003	2015	50	0.01	5,880 MW	1
Vermont	2005	2012	10	0.05	See Note 6	1
Wisconsin	2001	2011	10	0.006	2.2	0.75

Notes:
1) RPS data as of 8/16/05. Source: IREC 2006.
2) RPS Start Year is the "beginning" of the RPS program. The RPS is ramped linearly to the full implementation year.
3) RPS Full Implementation is the year that the full RPS fraction must be met. WinDS assumes the fraction met is ramped up linearly between the start year and the full implementation year.
4) WinDS Assumed RPS Fraction is the fraction of state demand that must be met by wind by the full implementation year. This value is based on the total state RPS requirement and adjusted to estimate the fraction actually provided by wind since WinDS does not currently include other renewables such as biomass cofiring and certain hydro projects.
5) Load fraction is the fraction of the total state load that must meet the RPS. In certain locations, municipal or cooperative power systems may be exempt from the RPS.
6) Several states have special funds set aside to promote renewables. The net increase in wind due to these funds was estimated and applied as an effective RPS.

B.8 Electricity Sector Direct Cost Calculation

The objective of the electricity sector direct cost calculation is to determine the difference in system-wide costs where 20% wind penetration is required compared to the case where no new wind generation is installed after 2006. The goal was to estimate the cost per kilowatt-hour of wind produced and the cost per kilowatt-hour of the total load met. The resulting numbers for both scenarios are reported in Appendix A.

To gather necessary costs from the WinDS model, it was programmed to calculate costs incurred in each year of the simulation from 2008 through 2030 for both cases (with and without wind). These costs are then broken into subgroups, including wind capital costs; conventional energy capital costs; wind and conventional transmission build costs (including the full transmission cost, not just the portion shared by each generator); and conventional fuel costs.

Because the impacts of reduced fuel demand and wind turbines installed in the years immediately preceding 2030 are not evident until after 2030, the cost impacts beyond 2030 are estimated. To arrive at the estimate, the model assumes that wind generation would linearly decay from 2030 to 2050 and that the conventional fuel and O&M savings would also linearly decay to 0 from 2030 to 2050. This is a conservative approach because it assumes that the wind farms are retired linearly.

Finally, all costs (including the approximated costs after 2030) are discounted back to 2006. The WinDS model is run with an 8.5% real weighted cost of capital to represent a typical utility perspective. In evaluating a policy such as an RPS, a social discount rate of 7% should be used in accordance with Office of Management and Budget guidelines (OMB 1992). This lower rate effectively places higher (higher than a utility's 8.5% discount rate) value on benefits and costs encountered further in the future. The total cost difference then becomes the difference in the present value of the two cost streams. To find the cost per kilowatt-hour (levelized cost) of wind produced, the total cost difference is levelized to satisfy the following formula:

$\sum \text{wind generation}_t * LC/(1+d)^t$ = PV of costs in 20% case – PV of costs in no wind case

As a second result, to find the cost per kilowatt-hour of total generation, replace wind generation with total generation in the preceding formula. The complete equation to calculate the present value of costs used in the preceding equation is as follows:

$$PV_{Costs} = a + b + c$$

$$a = \sum_{t=2006}^{2030} \left(\left(CapCostNewCapacity_t + CapCostNewTransmission_t + O\&MCost_t + FuelCost_t \right) / (1 + d)^{(t-2006)} \right)$$

$$b = \sum_{t=2031}^{2050} \left(WindO\&MCostsCapBuiltBy2030_t \; / \; (1 + d)^{(t-2006)} \right)$$

$$c = \sum_{t=2031}^{2050} \left(\left(\left(ConvO\&M_{2030} + Fuel_{Cost,2030} \right) FractionNotRetiredWind \right) / \left(1 + d^{(t-2006)} \right) \right)$$

where

FractionNotRetiredWind = Fraction of wind generation remaining from wind capacity installed prior to 2031 in the 20% wind case

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Notes: Many of the assumptions about conventional generation and fuel prices are drawn from the EIA's National Energy Modeling System. This information is published in the AEO, which consists of three documents: the main AEO (which focuses on results); the supplemental tables (which contain additional details on results at the regional level); and the assumptions (which presents input details). Several sources for emissions data are available from the EPA, including the AP-42 series of documents. Detailed emissions estimates for different combustion technologies and emissions controls can be found in the AP-42 series. The eGRID database estimates emissions rates from existing plants, based on measured fuel use and continuous emissions monitoring system data measurement.

B

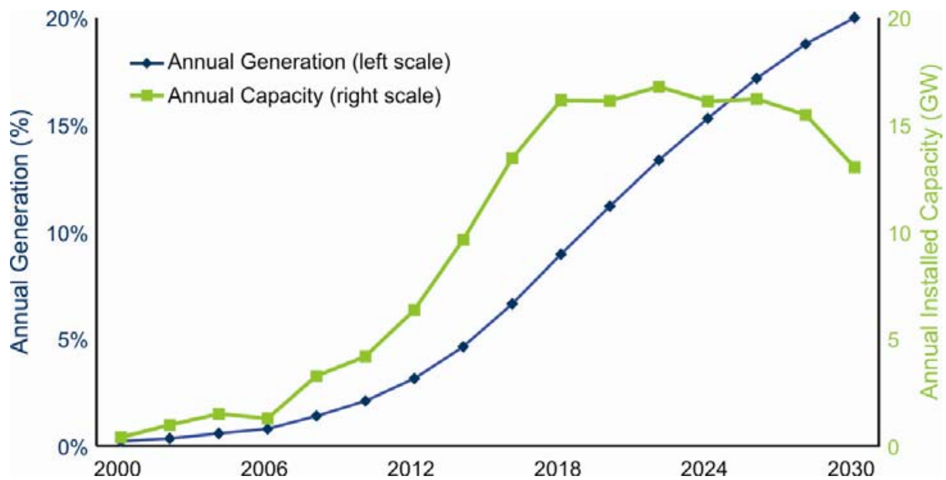
Appendix C. Wind-Related Jobs and Economic Development

This appendix details the economic model used to project the employment and economic development impacts of the 20% Wind Scenario described in Appendix A. Ramping up wind capacity and electricity output from wind would displace jobs and economic activity elsewhere. However, identifying such transfers accurately would be very difficult. Therefore, the impacts cited here do not constitute impacts to the U.S. economy overall but are specific to the wind industry and related industries. The impacts were calculated using the Jobs and Economic Development Impacts (JEDI) model, based in part on data from the Wind Deployment System (WinDS) model (developed by the National Renewable Energy Laboratory [NREL]). Appendix A summarizes the WinDS modeled scenario, and specific assumptions are described in Appendix B. Cost and performance projections for this analysis were supplied by Black & Veatch (Black & Veatch 2007) and are detailed in Appendix B.

The 20% Wind Scenario was constructed by specifying annual wind energy generation for every year from 2007 to 2030. The specifications were based on a trajectory proposed in an NREL study (Laxson, Hand, and Blair 2006). The NREL study forced the WinDS model to reach the 20% level for wind-generated electricity by 2030. The investigators evaluated aggressive near-term growth rates followed by sustainable levels of wind capacity installations that would maintain electricity generation levels at 20% and accommodate the repowering of aging wind installations beyond 2030. The 20% wind by 2030 trajectory was implemented in WinDS by calculating the percentage of annual energy production from wind at an increase of approximately 1% per year. Figure C-1 illustrates the energy generation trajectory proposed by the NREL study with the corresponding annual wind capacity installations that the WinDS model projects will meet these energy-generation percentages.

The combined cost, technology, and operational assumptions in the WinDS model show that an annual installation rate of about 16 gigawatts per year (GW/year) reached by 2018 could result in generation capacity capable of supplying 20% of the nation's electricity demand by 2030. This annual installation rate is affected by the quality of wind resources selected for development as well as future wind turbine performance. The declining annual installed capacity after 2024 is an artifact of the prescribed energy generation from the NREL study, which did not consider technology improvement and wind resource variation. The NREL study provides an upper level of about 20 GW/year, because turbine performance is unchanged over time and only one wind resource power class was assumed. Based on the wind resource data and the projected wind technology improvements presented in this report, sustaining a level of annual installations at approximately 16 GW/year beyond 2030 would accommodate the repowering of aging wind turbine equipment along with increased electricity demand, so that the nation's energy demand would

Figure C-1. Prescribed annual wind technology generation as a percentage of national electricity demand from Laxson, Hand, and Blair (2006) and corresponding annual wind capacity installation for 20% Wind Scenario from WinDS model.



continue to be met by 20% wind. This installation level could maintain energy production of 20% of the nation's demand. Additionally, this scenario shows that this level of wind development could accommodate the repowering of aging wind turbine equipment. Specific policy incentives necessary for this growth, such as a production tax credit (PTC) or carbon regulation policy, are not modeled.

To obtain 20% of U.S. electricity from wind by 2030, changes in the wind power and electricity industries would need to be made. These changes, which are discussed in the body of this report, include advances in domestic manufacturing of wind turbine components; training, labor, and materials for installation of wind farms and operations and maintenance (O&M) functions; and improvements in wind technology and electric power system infrastructure. This appendix covers the output from the JEDI model, which shows the potential employment impacts from this scenario along with other impacts to the United States associated with new wind installations.

C

C.1 The JEDI Model

C.1.1 Model Description

The JEDI model was developed in 2002 for NREL to demonstrate the state and local economic development impacts associated with developing wind power plants in the United States. These impacts include employment numbers created in the wind power sector, and the increase in overall economic activity associated with the construction and operating phases of new wind power. The JEDI spreadsheet-based model for wind is free and available to the public. It can be downloaded from the Wind Powering America website: www.windpoweringamerica.gov. Documentation is listed on the same site. For questions, please contact Marshall Goldberg at mrgassociates@earthlink.net or Suzanne Tegen at suzanne_tegen@nrel.gov.

JEDI was initially designed to estimate economic impacts to state economies. Subsequent enhancements made the model capable of performing county, regional, and national analyses as well. This particular analysis focuses primarily on economic impacts for the United States as a whole, although some state and regional results are presented.

To calculate economic impacts, the model relies on investment and expenditure data from the 20% Wind Scenario for the period between 2007 and 2030. The model also uses industry multipliers that trace supply linkages in the economy. For example, the analysis shows how wind turbine purchases benefit not only turbine manufacturers, but also the fabricated metal industries and other businesses that supply inputs (goods and services) to those manufacturers.

The model evaluates three separate impacts for each expenditure: direct, indirect, and induced.

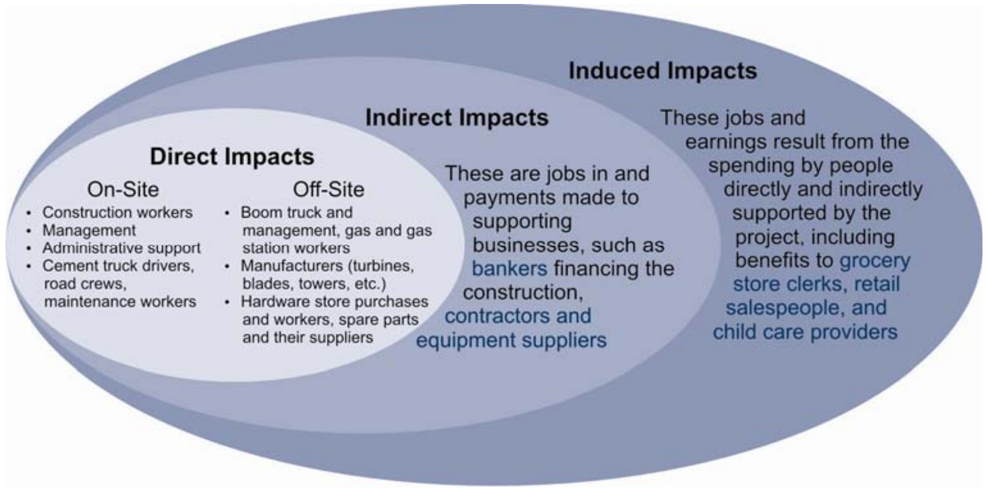
- **Direct impacts** are the on-site or immediate effects created by spending money for a new wind project. In the JEDI model, the construction phase includes the on-site jobs of the contractors and crews hired to construct the plant as well as their managers and staffs. Direct impacts also include jobs at the manufacturing plants that build the turbines as well as the jobs at the factories that produce the towers and blades.[18]
- **Indirect impacts** refer to the increase in economic activity that occurs, for example, when a contractor, vendor, or manufacturer receives payment for goods or services and in turn is able to pay others who support their business. This includes the banker who finances the contractor and the accountant who keeps the contractor's books, as well as the steel mills, electrical part manufacturers, and suppliers of other necessary materials and services.
- **Induced impacts** are the changes in wealth that result from spending by people directly and indirectly employed by the project. For example, when plant workers and other local workers receive income from expenditures related to the plant, they in turn purchase food, clothing, and other goods and services from local business.

The sum of these three impacts is the total impact from the turbine's construction. Figure C-2 illustrates this ripple effect, from direct impacts to induced impacts. This figure excludes the impacts on other energy sectors as wind power displaces other sources of energy.

JEDI relies on U.S.-specific multipliers and personal expenditure patterns. These multipliers—for patterns of employment, wage and salary income, output (economic activity), and personal spending (expenditure)—are adapted from the IMPLAN Professional Software model (Minnesota IMPLAN Group, Inc., Stillwater, Minnesota; see http://www.implan.com). The IMPLAN® model is based on U.S. industry and census data. Spending from new investments (e.g., purchases of equipment and services) to construct and operate wind plants is matched with the appropriate multipliers for each industry sector (e.g., construction, electrical

[18] When an impact analysis is conducted in this manner, the definitions of *direct* and *indirect* are changed somewhat. Typically, the change in final demand to an industry (in this instance the wind industry) is seen as the direct effect. In the JEDI model, the direct effect includes what are usually called first-round indirect effects (e.g., demand to manufacturers and other goods and service suppliers). The JEDI indirect effects are all subsequent rounds of the industry indirect effects.

Figure C-2. Wind's economic ripple effect



equipment, machinery, professional services, and others) affected by the change in expenditure.

Outputs from the JEDI model are reported for two distinct phases: the construction phase and the annual operations phase. The construction period outputs represent the entire construction period (typically one year for a utility-scale wind project, although this can vary depending on the size of the project). The outputs for the operating period represent the jobs and economic impacts created for one year of operation.

C.1.2 Caveats

Before noting the specific economic impacts from the 20% Wind Scenario, it is important to underscore several caveats about the JEDI model.

First, the model is considered static. As such, it relies on inter-industry relationships and personal consumption patterns at the time of the analysis. The model does not account for feedback through demand, increases, or reductions that could result from price changes. Similarly, the model does not account for feedback from inflationary pressures or potential constraints on local labor and money supplies. In addition, the model assumes that adequate local resources and production and service capabilities are available to meet the level of local demand identified in the model's assumptions. For new power plants, the model does not automatically take into account improvements in industry productivity over time, changes during construction, or changes in O&M processes (e.g., production recipe for labor, materials, and service cost ratios). To adjust for advancements in technology or changes in wages and salaries, the model is run with new cost assumptions (e.g., once with a construction cost of $1,650/kW and again with a construction cost – excluding construction financing - of $1,610/kW).

Second, the intent of using the JEDI model is to construct a reasonable profile of investments (e.g., wind power plant construction and operating costs) to demonstrate the economic impacts that will likely result during the construction and operating periods. Given the potential for future changes in wind power plant costs beyond those identified, and potential changes in industry and personal consumption patterns in the economy noted earlier, the analysis is not intended to provide a precise forecast, but rather an estimate of overall economic impacts in the wind energy sector from specific scenarios.

Third, because the analysis and results are specific to developing new land-based and offshore wind power plants only, this is considered a gross analysis. The results do not reflect the net impacts of construction or operation of other types of electricity-generating power plants or replacement of existing power generation resources to meet growing needs.

Fourth, the analysis assumes that the output from the wind power plants and the specific terms of the power purchase agreements generate sufficient revenues to accommodate the equity and debt repayment and annual operating expenditures.

And finally, the analysis period is 2007 through 2030; additional impacts beyond these years are not considered.

C.2 Wind Scenario Inputs

To assess the economic development from the addition of 293 GW of wind technology in the United States, the authors relied on inputs from the WinDS model. The detailed cost and performance projections can be found in Appendix B of this report.

Table C-1 summarizes the wind data assumptions used in the JEDI model. The cost data are allocated into expenditure categories. Each category includes the portion of the expenditure that goes to the local area, which in this case is the entire United States.

Table C-1. JEDI wind modeling assumptions

Category	Land-Based	Shallow Offshore	Total
Period of Analysis	2007-2030	2007-2030	
Nameplate Capacity	239.5 GW	53.9 GW	293.4 GW
Number of Turbines	79,130	17,976	97,106
Turbine Size	1500–5000 kW	3000 kW	
Technology Cost[1] per kW			
2007	$1650	$2400	
2010	$1650	$2300	
2015	$1610	$2200	
2020	$1570	$2150	
2025	$1530	$2130	
2030	$1480	$2100	
O&M Costs			
Fixed[2]	$11.50/kW	$15.00/kW	
Variable[3]			
2004	$7.00/MWh	$21.00/MWh	
2010	$5.50/MWh	$18.00/MWh	
2015	$5.00/MWh	$16.00/MWh	
2020	$4.60/MWh	$14.00/MWh	
2025	$4.50/MWh	$13.00/MWh	

Category	Land-Based	Shallow Offshore	Total
2030	$4.40/MWh	$11.00/MWh	
U.S. Spending			
Labor	100%	100%	
Materials and Services	100%	100%	
Equipment (Manufacturing Transition)[4]			
Major Components			
Blades	50% in 2007 to 80% in 2030		
Towers	26% in 2007 to 50% in 2030		
Machine Heads	20% in 2007 to 42% in 2030		
Sub-Components	10% in 2007 to 30% in 2030		

Notes: 1. All dollar values are 2006 dollars. Technology costs exclude construction financing costs and regional cost variations that result from increased population density, elevation, or other considerations that are included in the WinDS model. Thus, the cumulative investment costs presented in this study are lower than those presented in Appendix A. 2. Fixed costs include land lease cost. 3. Variable costs include property taxes. 4. Refers to U.S. manufacturing/assembly for turbines, blades and towers. For purposes of this modeling, the transition (percentage of U.S. manufacturing/assembly) is assumed to occur at an average annual rate over the 24-year period.

As explained earlier, the JEDI model uses project expenditures—or spending—for salaries, services, and materials to calculate the total economic impacts. Table C-2 summarizes the expenditure data used in the analysis.

Table C-2. Wind plant expenditure data summary (in millions)

Category	Onshore	Offshore	All Wind
Total Cumulative Construction Cost (2007-2030)	$379,343	$115,790	$495,133
Domestic Spending	$200,192	$94,690	$294,882
Total Annual Operational Expenses in 2030 (300 GW)	$63,618	$20,765	$84,383
Direct O&M Costs	$4,394	$2,861	$7,255
Other Annual Costs	$59,224	$17,904	$77,128
Property Taxes	$1,533	$345	$1,877
Land Lease	$639	$144	$783

Notes: All dollar values are 2006 dollars. All dollars represent millions of dollars. Though some of the money spent during construction leaves the country, all O&M spending is domestic.

C.3 Findings

As Table C-3 indicates, developing 293 GW of new land-based and offshore wind technologies from 2007 to 2030 could have significant economic impacts for the entire United States. Cumulative economic activity from the construction phase alone will reach more than $944 billion for direct, indirect, and induced activity in the nation. This level of economic activity stimulates an annual average of more than 250,000 workers required for employment in the wind power and related sectors from 2007 forward. Of these average annual positions, the wind industry supports 70,000 full-time workers in construction-related sectors, including more than 47,000 full-time workers directly in construction and 22,000 workers in manufacturing. As noted earlier, this estimate does not take into account the offsetting effects on employment in other energy sectors.

Table C-3. U.S. construction-related economic impacts from 20% wind

Average Annual Impacts	Jobs	Earnings	Output	
Direct Impacts	72,946	$5,221	$12,217	
Construction Sector Only	47,020	$3,547		
Manufacturing Sector Only	22,346	$1,446		
Other Industry Sectors	3,580	$228		
Indirect Impacts	66,035	$3,008	$11,377	
Induced Impacts	119,774	$4,483	$15,749	
Total Impacts (Direct, Indirect, Induced)	258,755	$12,712	$39,343	
Total Construction Impacts 2007-2030	**Jobs**	**Earnings**	**Output**	**NPV of Output**
Direct Impacts	1,750,706	$125,305	$293,197	$111,153
Construction Sector Only	1,128,479	$85,129		
Manufacturing Sector Only	536,305	$34,706		
Other Industry Sectors	85,922	$5,471		
Indirect Impacts	1,584,842	$72,197	$273,057	$103,541
Induced Impacts	2,874,582	$107,591	$377,984	$143,367
Total Impacts (Direct, Indirect, Induced)	6,210,129	$305,093	$944,238	$358,061

Note: All dollar values are millions of 2006 dollars. Average annual Jobs are full-time equivalent for each year of the construction period. Cumulative jobs are total full-time equivalent for the 24-year construction period from 2007 through 2030. The NPV column shows the net present value of the output column with a discount rate of 7%, per guidance from the Office of Management and Budget.

Under this scenario, the wind industry would produce 305 GW/year. By 2020, the economic activity generated from annual operations of the wind turbines would exceed $27 billion/year. The number of wind plant workers alone would grow to more than 28,000/year, and total wind-related employment would exceed 215,000 workers (see Table C-4).

Table C-4. U.S. operations-related economic impacts from 20% wind

Operation of 300 GW in 2030	Jobs	Earnings	Output	
Direct Impacts	76,667	$3,643	$8,356	
Plant Workers Only	28,557	$1,617		
Nonplant Workers	48,110	$2,026		
Indirect Impacts	37,785	$1,624	$5,642	
Induced Impacts	102,126	$3,822	$13,429	
Total Impacts (Direct, Indirect, Induced)	216,578	$9,090	$27,427	

Total Operation Impacts 2007-2030	Jobs	Earnings	Output	NPV of Output
Direct Impacts	1,163,297	$55,907	$122,463	$26,072
Property Tax			$1,877	$760
Land Lease			$783	$317
Other Direct Impacts			$119,804	$24,996
Plant Workers Only	482,578	$27,458		
Nonplant Workers	680,719	$28,449		
Indirect Impacts	561,107	$24,118	$84,008	$17,674
Induced Impacts	1,591,623	$59,572	$209,286	$42,569
Total Impacts (Direct, Indirect, Induced)	3,316,027	$139,596	$415,757	$86,315

Note: All dollar values are millions of 2006 dollars. Operation jobs in 2030 are full-time equivalent for operation of the 305 GW fleet existing in 2030. Cumulative jobs are total full-time equivalent for the 24-year construction period from 2007 through 2030. The NPV column shows the net present value of the output column with a discount rate of 7%, per guidance from the Office of Management and Budget.

Figure C-3 shows the economic impacts from direct, indirect, and induced impacts .

Figure C-3. Annual direct, indirect and induced economic impacts from 20% scenario

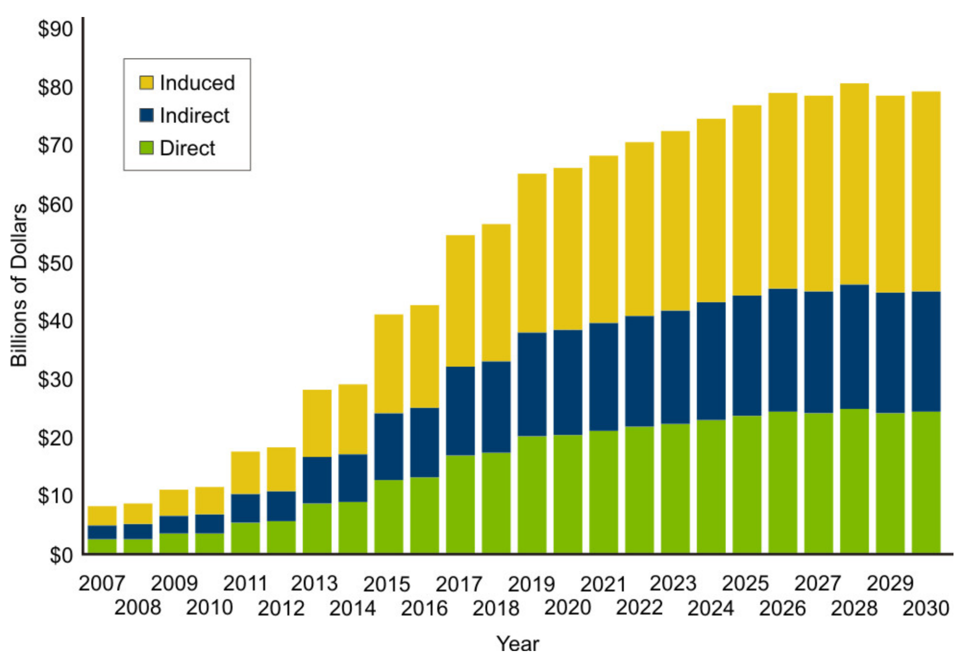
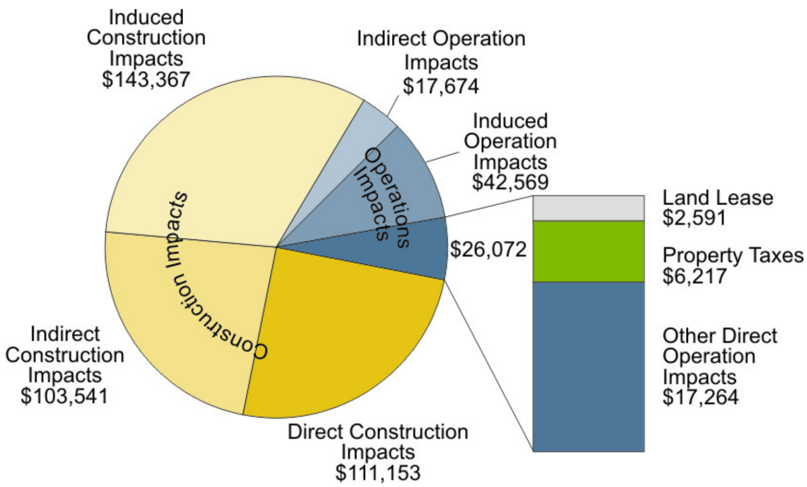


Figure C-4 displays the total economic impacts on a relative basis. The impacts of both the construction and the operation phases are included for the entire period from 2007 through 2030.

The 20% Wind Scenario shows the U.S. wind industry growing from its current 3 GW/year in 2007 to a sustained 16 GW/year by around 2018. In the following sections, employment impacts in the wind industry are divided into three major industry sectors: manufacturing, construction, and operations. Each sector is

C

Figure C-4. Total economic impacts of 20% wind energy by 2030 on a relative basis



described during the year of its maximum employment supported by the wind industry.

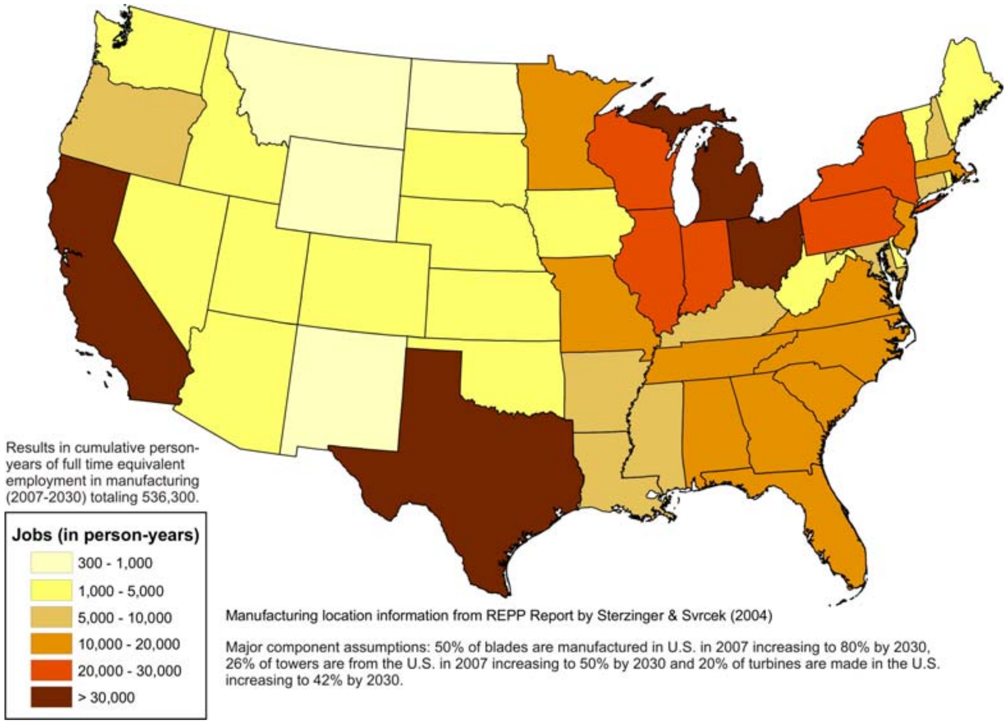
The JEDI model estimates the number of jobs supported by one project throughout the economy, as well as the total economic output from the project. Results from the JEDI model do not include macroeconomic effects. Instead, the model focuses on jobs and impacts supported by specific wind projects. In other words, the employment estimates from the JEDI model look only at gross economic impacts from this 20% Wind Scenario.

C.4 Manufacturing Sector

The 20% Wind Scenario includes the prospect of significantly expanding wind power manufacturing capabilities in the United States. In 2026, this level of wind development supports more than 32,000 U.S. manufacturing full-time workers, including land-based and offshore wind projects. These employment impacts are directly related to producing the major components and subcomponents for the turbines, towers, and blades installed in the United States. Although the level of domestic wind installations declines after 2021 in the scenario modeled, the manufacturing and construction industries have the potential to maintain a high level of employment and expand further to meet increasing global demand.

To estimate the potential location for manufacturing jobs, data from a non-governmental organization, Renewable Energy Policy Project (REPP), report were used (Sterzinger and Svrcek 2004). The REPP report identified existing U.S. companies with the technical potential to enter the wind turbine market. The map in Figure C-5 was created using the percentages of manufacturing capability in each state and JEDI's manufacturing jobs output. Again, these potential manufacturing jobs from the REPP report are based on technical potential existing in 2004, without assuming increased productivity or expansion over time. The data also assumes that existing facilities that manufacture components similar to wind turbine components are modified. Most of the manufacturing jobs in this scenario are located in the Great Lakes region, where manufacturing jobs are currently being lost. Even states

Figure C-5. Potential manufacturing jobs created by 2030



without a significant wind resource can be impacted economically from new manufacturing jobs (e.g., southeastern US).

C.5 Construction Sector

The year 2021 represents the height of the wind plant construction period, with 16.7 GW of wind having been brought online. In that year, more than 65,000 construction industry workers are assumed to be employed and $54.5 billion is generated in the U.S. economy from direct, indirect, and induced construction spending.

To reach the 20% Wind Scenario, today's wind power industry would have to grow from 9,000 annual construction jobs in 2007 to 65,000 new annual construction jobs in 2021. Construction jobs could be dispersed throughout the United States. Assuming the 16 GW/year capacity can be maintained into the future, including the replacement of outdated wind plants, the industry could maintain 20% electricity from wind as demand grows. In this scenario, the construction sector would experience the largest increase in jobs, followed by the operations sector, and then by the manufacturing sector. Figure C-6 shows the direct employment impact on the construction sector, the manufacturing sector and the operations sector (plant workers only).

Figure C-7 shows employment impacts during the same years, but adds the indirect and induced jobs. The bottom three bars (manufacturing, construction, and operations—including plant workers and other direct jobs) are direct jobs only. This chart depicts the large impact from the indirect and induced job categories, compared to the initial direct expenditures in the direct categories.

Figure C-6. Direct manufacturing, construction, and operations jobs supported by the 20% Wind Scenario

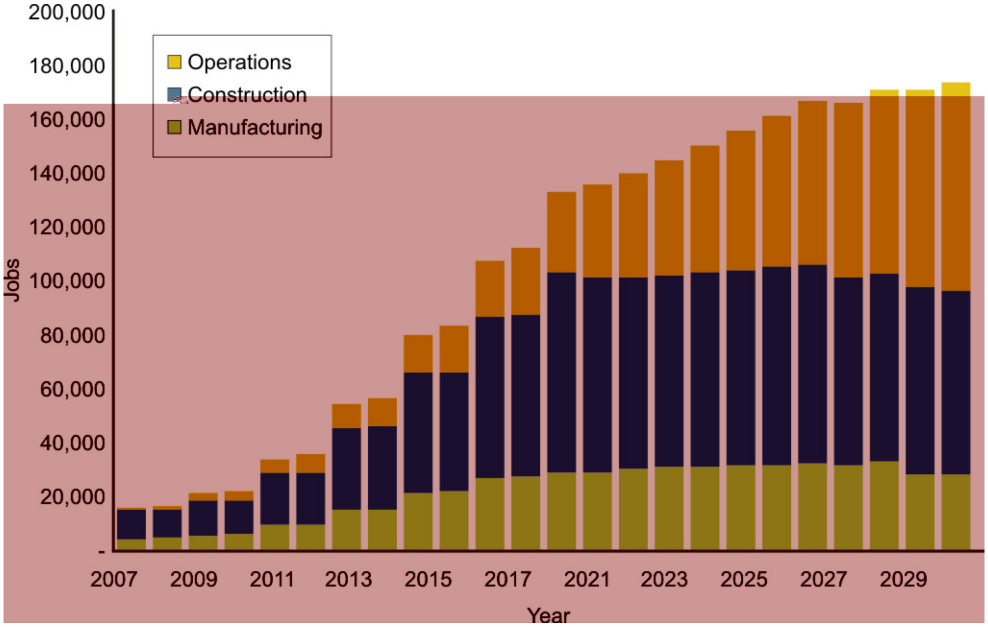
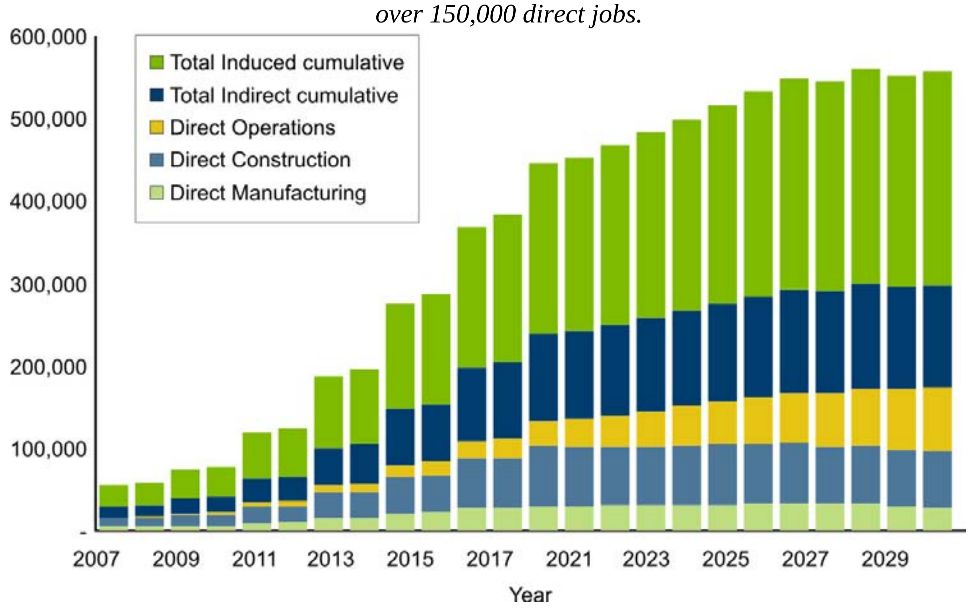


Figure C-7. Jobs per year from direct, indirect, and induced categories

In the last ten years of the scenario, the wind industry could support 500,000 jobs, including over 150,000 direct jobs.



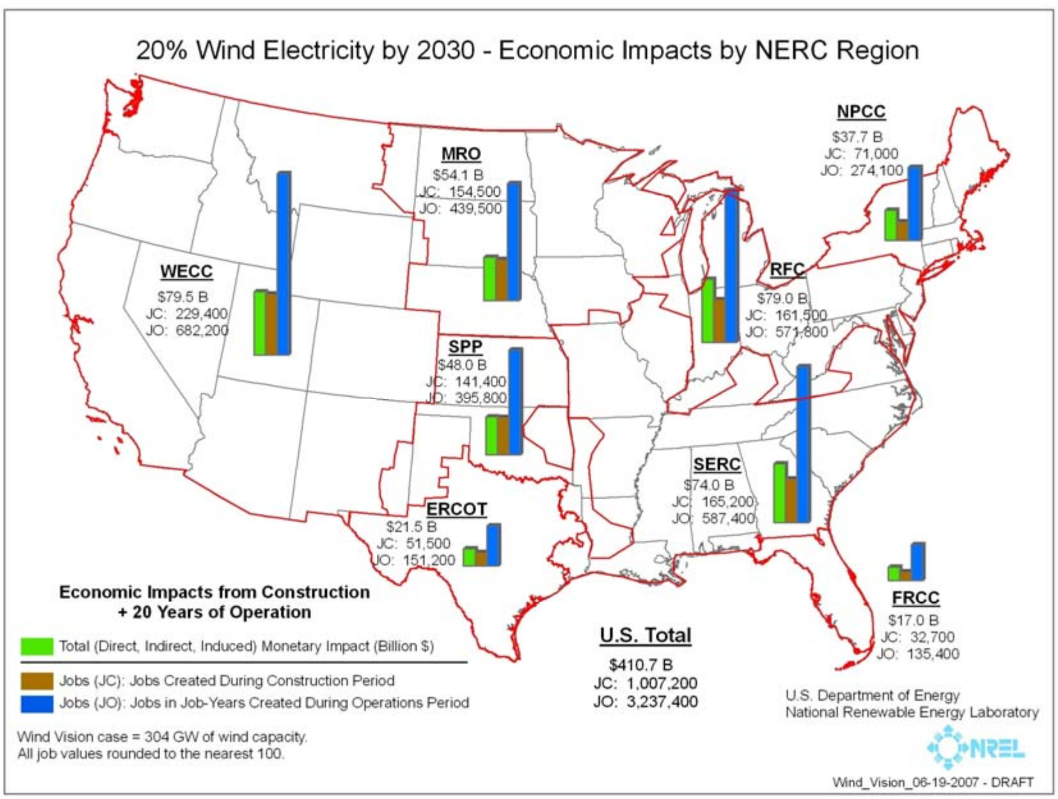
C.6 Operations Sector

JEDI predicts that in 2030, employment of more than 215,000 total operations workers (direct, indirect, and induced) will exist to maintain 293 GW of wind capacity. This includes more than 28,000 direct O&M jobs and 48,000 other direct jobs related to operating a wind plant (e.g., utility services and subcontractors). JEDI predicts that in 2030, land-based and offshore wind project operations will have a total economic impact of $27 billion. Operations employment would be dispersed across the country and is likely to be near wind installations. Rural Americans, in particular, could realize significant positive impacts from this scenario in the form of landowner payments and property taxes. Counties use property taxes to improve roads and schools, along with other vital infrastructure. More than $8.8 billion is estimated in property taxes and land lease payments between 2007 and 2030, which could be an important boost for rural communities.

Figure C-8 shows the results of JEDI analysis, performed on a state-by-state basis, in the form of impacts to each North American Electric Reliability Corporation (NERC) region. The individual state impacts were summed to calculate the NERC region impacts. These total impacts are lower than those from the JEDI analysis for the entire country because any job or dollar flowing out of state is considered monetary leakage (in the U.S. analysis, the model considers the whole country to be "local").

Figure C-8 shows jobs in job-years, which are FTE jobs counted in each year in which they exist. For example, if a maintenance worker holds one job for 20 years, this is shown as 20 job-years. For this figure, jobs during construction are assumed to last for one year. Jobs during the operations period are assumed to last for 20 years. Economic impacts are direct, indirect, and induced. Because it represents impacts from 305 GW of new wind starting in 2004 and ending in 2030, Figure C-8 shows three additional years when compared to other results.

Figure C-8. Jobs and economic impacts by NERC region



C.7 Conclusion

As a nation, the United States has made much progress recently in developing its wind resources. However, advancements in wind technologies and the projected increasing demand for electricity, will provide significant opportunities to further develop this domestic renewable resource. Actions toward this goal, as identified in the 20% Wind Scenario, offer residents and businesses in the rural and urban United States potential for economic development opportunities and potential for employment.

The United States is a prime location for developing wind resources and new wind manufacturing facilities. At the same time, relocating or expanding existing industries can give businesses opportunities to meet many of the material needs associated with wind technology manufacturing, installation, and facility operation.

In many areas of the country, renewable resources provide an opportunity to boost the local economy significantly. Wind plants offer employment during construction and continue to support permanent jobs during operation. Today, tax revenues from wind plants help to fund local schools, hospitals, and government services.

Based on the scenario presented in this report, a new and expanding wind manufacturing industry can meet 20% of our domestic electricity needs through 2030.

C.8 References

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Workshops and Outreach

Two strategic workshops took place during the course of this work. At the first of these, held August 17–18, 2006, attendees developed the initial statement of the 20% Wind Scenario and defined work plans. At the second, held November 9–10, 2006, participants shared and discussed preliminary results and obtained input from a group of invited individuals from key stakeholder sectors. Previously, these

[*] Lead authors and advisors for each chapter are shown in **bold.** Task force members are underlined and Task Force chairpersons are identified with an asterisk. Reviewers are shown in *italics*.

individuals had been external to the effort. Many of the authors, reviewers, and task force members listed in this appendix attended one or both of these workshops.

The invited participants at the November workshop brought along important feedback and perspectives from their respective sectors that have helped to shape this report. Some also reviewed sections of the report. Their participation is not meant to imply that they or their respective organizations either agree or disagree with the findings of the effort. These participants are listed below:

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On November 28, 2006, a topical outreach workshop was held with representatives from nongovernmental organizations concerned about wildlife conservation and the environment. Participants discussed the early findings of the Environment and Siting Task Force and offered insights into issues important to their organizations. Workshop attendees are listed below. Their participation is not meant to imply that they or their respective organizations either agree or disagree with the findings of the effort.

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Appendix E. Glossary

Area control error (ACE): The instantaneous difference between net actual and scheduled interchange, taking into account the effects of frequency deviations.

Balancing area (balancing authority area): The collection of generation, transmission, and loads within the metered boundaries of the balancing authority. The balancing authority maintains load-resource balance within this area.

Before-and-after control impact (BACI): A schematic method used to trace environmental effects from substantial anthropogenic changes to the environment. The overall aim of the method is to estimate the state of the environment before and after any change and the specific objectives is to compare changes at reference sites (or control sites) with the actual area of impact.

Bus: An electrical conductor that serves as a common connection for two or more electrical circuits.

Bus-bar: The point at which power is available for transmission.

Cap and trade: An established policy tool that creates a marketplace for emissions. Under a cap and trade program, the government regulates the aggregate amount of a type of emissions by setting a ceiling or cap. Participants in the program receive allocated allowances that represent a certain amount of pollutant and must purchase allowances from other businesses to emit more than their given allotment.

Capability: The maximum load that a generating unit, generating station, or other electrical apparatus can carry under specified conditions for a given period of time without exceeding approved limits of temperature and stress.

Capacity: The amount of electrical power delivered or required for which manufacturers rate a generator, turbine, transformer, transmission circuit, station, or system.

Capacity factor (CF): A measure of the productivity of a power plant, calculated as the amount of energy that the power plant produces over a set time period, divided by the amount of energy that would have been produced if the plant had been running at full capacity during that same time interval. Most wind power plants operate at a capacity factor of 25% to 40%.

Capacity penetration: The ratio of the nameplate rating of the wind plant capacity to the peak load. For example, if a 300-megawatt (MW) wind plant is operating in a zone with a 1,000 MW peak load, the capacity penetration is 30%. The capacity penetration is related to the energy penetration by the ratio of the system load factor to the wind plant capacity factor. For example, say that the system load factor is 60% and the wind plant capacity factor is 40%. In this case, and with an energy penetration of 20%, the capacity penetration would be 20% × 0.6/0.4, or 30%.

Capital costs: The total investment cost for a power plant, including auxiliary costs.

Carbon dioxide (CO_2): A colorless, odorless, noncombustible gas present in the atmosphere. It is formed by the combustion of carbon and carbon compounds (such as fossil fuels and biomass); by respiration, which is a slow form of combustion in animals and plants; and by the gradual oxidation of organic matter in the soil. CO_2 is a greenhouse gas that contributes to global climate change.

Carbon monoxide (CO): A colorless, odorless, but poisonous combustible gas. Carbon monoxide is produced during the incomplete combustion of carbon and carbon compounds, such as the fossil fuels coal and petroleum.

Circuit: An interconnected system of devices through which electrical current can flow in a closed loop.

Competitive Renewable Energy Zones (CREZ): A mechanism of the renewable portfolio standard in Texas designed to ensure that the electricity grid is extended to prime wind energy areas. The designation of these areas directs the Electric Reliability Council of Texas to develop plans for transmission lines to these areas that will connect them with the grid. See also "Electric Reliability Council of Texas" and "renewable portfolio standard."

Conductor: The material through which electricity is transmitted, such as an electrical wire.

Conventional fuel: Coal, oil, and natural gas (fossil fuels); also nuclear fuel.

Cycle: In AC electricity, the current flows in one direction from zero to a maximum voltage, then back down to zero, then to a maximum voltage in the opposite direction. This comprises one cycle. The number of complete cycles per second determines the frequency of the current. The standard frequency for AC electricity in the United States is 60 cycles.

Dispatch: The physical inclusion of a generator's output onto the transmission grid by an authorized scheduling utility.

Distribution: The process of distributing electricity. Distribution usually refers to the series of power poles, wires, and transformers that run between a high-voltage transmission substation and a customer's point of connection.

Effective load-carrying capability (ELCC): The amount of additional load that can be served at the target reliability level by adding a given amount of generation. For example, if adding 100 MW of wind could meet an increase of 20 MW of system load at the target reliability level, the turbine would have an ELCC of 20 MW, or a capacity value of 20% of its nameplate value.

E

Electricity generation: The process of producing electricity by transforming other forms or sources of energy into electrical energy. Electricity is measured in kilowatt-hours.

Electric Reliability Council of Texas (ERCOT): One of the 10 regional reliability councils of the North American Electric Reliability Council. ERCOT is a membership-based 501(c)(6) nonprofit corporation, governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT manages the flow of electric power to approximately 20 million customers in Texas, representing 85% of the state's electric load and 75% of the Texas land area. See also "North American Electric Reliability Council."

Energy: The capacity for work. Energy can be converted into different forms, but the total amount of energy remains the same.

Energy penetration: The ratio of the amount of energy delivered from one type of resource to the total energy delivered. For example, if 200 megawatt-hours (MWh) of wind energy supplies 1,000 MWh of energy consumed, wind's energy penetration is 20%.

Externality: A consequence that accompanies an economic transaction, where that consequence affects others beyond the immediate economic actors and cannot be limited to those actors.

Feed-in law: A legal obligation on utilities to purchase electricity from renewable sources. Feed-in laws can also dictate the price that renewable facilities receive for their electricity.

Frequency: The number of cycles through which an alternating current passes per second, measured in hertz.

Gearbox: A system of gears in a protective casing used to increase or decrease shaft rotational speed.

Generator: A device for converting mechanical energy to electrical energy.

Gigawatt (GW): A unit of power, which is instantaneous capability, equal to one million kilowatts.

Gigawatt-hour (GWh): A unit or measure of electricity supply or consumption of one million kilowatts over a period of one hour.

Global warming: A term used to describe the increase in average global temperatures caused by the greenhouse effect.

Green power: A popular term for energy produced from renewable energy resources.

Greenhouse effect: The heating effect that results when long-wave radiation from the sun is trapped by greenhouse gases produced by natural and human activities.

Greenhouse gases (GHGs): Gases such as water vapor, CO_2, methane, and low-level ozone that are transparent to solar radiation, but opaque to long-wave radiation. These gases contribute to the greenhouse effect.

Grid: A common term that refers to an electricity transmission and distribution system. See also "power grid" and "utility grid."

Grid codes: Regulations that govern the performance characteristics of different aspects of the power system, including the behavior of wind plants during steady-state and dynamic conditions. These fundamentally technical documents contain the rules governing the operations, maintenance, and development of the transmission system and the coordination of the actions of all users of the transmission system.

Heat rate: A measure of the thermal efficiency of a generating station. Commonly stated as British thermal units (Btu) per kilowatt-hour. *Note:* Heat rates can be expressed as either gross or net heat rates, depending whether the electricity output is gross or net generation. Heat rates are typically expressed as net heat rates.

Instantaneous penetration: The ratio of the wind plant output to load at a specific point in time, or over a short period of time.

Investment tax credit (ITC): A tax credit that can be applied for the purchase of equipment such as renewable energy systems.

Kilowatt (kW): A standard unit of electrical power, which is instantaneous capability equal to 1,000 watts.

Kilowatt-hour (kWh): A unit or measure of electricity supply or consumption of 1,000 watts over a period of one hour.

Leading edge: The surface part of a wind turbine blade that first comes into contact with the wind.

Lift: The force that pulls a wind turbine blade.

Load (electricity): The amount of electrical power delivered or required at any specific point or points on a system. The requirement originates at the consumer's energy-consuming equipment.

Load factor: The ratio of the average load to peak load during a specified time interval.

Load following: A utility's practice in which more generation is added to available energy supplies to meet moment-to-moment demand in the utility's distribution system, or in which generating facilities are kept informed of load requirements. The goal of the practice is to ensure that generators are producing neither too little nor too much energy to supply the utility's customers.

Megawatt (MW): The standard measure of electricity power plant generating capacity. One megawatt is equal to 1,000 kilowatts or 1 million watts.

Megawatt-hour (MWh): A unit or energy or work equal to1,000 kilowatt-hours or 1 million watt-hours.

Met tower: A meteorological tower erected to verify the wind resource found within a certain area of land.

Modified Accelerated Cost Recovery System (MACRS): A U.S. federal system through which businesses can recover investments in certain property through depreciation deductions over an abbreviated asset lifetime. For solar, wind, and geothermal property placed in service after 1986, the current MACRS property class is five years. With the passage of the Energy Policy Act of 2005, fuel cells, microturbines, and solar hybrid lighting technologies became classified as five-year property as well.

Nacelle: The cover for the gearbox, drivetrain, and generator of a wind turbine.

Nameplate rating: The maximum continuous output or consumption in MW of an item of equipment as specified by the manufacturer.

Nondispatchable: The timing and level of power plant output generally cannot be closely controlled by the power system operator. Other factors beyond human control, such as weather variations, play a strong role in determining plant output.

Nitrogen oxides (NO_x): The products of all combustion processes formed by the combination of nitrogen and oxygen. NO_x and sulfur dioxide (SO_2) are the two primary causes of acid rain.

Power: The rate of production or consumption of energy.

Power grid: A common term that refers to an electricity transmission and distribution system. See also "utility grid."

Power marketers: Business entities engaged in buying and selling electricity. Power marketers do not usually own generating or transmission facilities, but take ownership of the electricity and are involved in interstate trade. These entities file with the Federal Energy Regulatory Commission (FERC) for status as a power marketer.

Power Purchase Agreement (PPA): A long-term agreement to buy power from a company that produces electricity.

Power quality: Stability of frequency and voltage and lack of electrical noise on the power grid.

Public Utility Commission: A governing body that regulates the rates and services of a utility.

Public Utility Regulatory Policies Act (PURPA) of 1978: As part of the National Energy Act, PURPA contains measures designed to encourage the conservation of energy, more efficient use of resources, and equitable rates. These measures included suggested retail rate reforms and new incentives for production of electricity by cogenerators and users of renewable resources.

Production tax credit (PTC): A U.S. federal, per-kilowatt-hour tax credit for electricity generated by qualified energy resources. Originally enacted as part of the Energy Policy Act of 1992, the credit expired at the end of 2001, was extended in March 2002, expired at the end of 2003, was renewed on October 4, 2004 and was then extended through December 31, 2008.

Radioactive waste: Materials remaining after producing electricity from nuclear fuel. Radioactive waste can damage or destroy living organisms if it is not stored safely.

Ramp rate: The rate at which load on a power plant is increased or decreased. The rate of change in output from a power plant.

Renewable energy: Energy derived from resources that are regenerative or that cannot be depleted. Types of renewable energy resources include wind, solar, biomass, geothermal, and moving water.

Regional Greenhouse Gas Initiative (RGGI): An agreement among 10 northeastern and mid-Atlantic states to reduce CO_2 emissions. Through the initiative, the states will develop a regional strategy to control GHGs. Fundamental to the agreement is the implementation of a multistate cap and trade program to induce a market-based emissions controlling mechanism.

Renewable energy credit (REC) or certificate: A mechanism created by a state statute or regulatory action to make it easier to track and trade renewable energy. A single REC represents a tradable credit for each unit of energy produced from qualified renewable energy facilities, thus separating the renewable energy's environmental attributes from its value as a commodity unit of energy. Under a REC regime, each qualified renewable energy producer has two income streams—one from the sale of the energy produced, and one from the sale of the RECs. The RECs can be sold and traded and their owners can legally claim to have purchased renewable energy.

Renewable portfolio standard (RPS): Under such a standard, a certain percentage of a utility's overall or new generating capacity or energy sales must be derived from renewable resources (e.g., 1% of electric sales must be from renewable energy in the year 200x). An RPS most commonly refers to electricity sales measured in megawatt-hours, as opposed to electrical capacity measured in megawatts.

Restructuring: The process of changing the structure of the electric power industry from a regulated guaranteed monopoly to an open competition among power suppliers.

Rotor: The blades and other rotating components of a wind turbine.

Solar energy: Electromagnetic energy transmitted from the sun (solar radiation).

Sulfur dioxide (SO_2): A colorless gas released as a by-product of combusted fossil fuels containing sulfur. The two primary sources of acid rain are SO_2 and NO_x.

Trade wind: The consistent system of prevailing winds occupying most of the tropics. Trade winds, which constitute the major component of the general circulation of the atmosphere, blow northeasterly in the northern hemisphere and southeasterly in the southern hemisphere. The trades, as they are sometimes called, are the most persistent wind system on Earth.

Turbine: A term used for a wind energy conversion device that produces electricity. See also "wind turbine."

Turbulence: A swirling motion of the atmosphere that interrupts the flow of wind.

Utility grid: A common term that refers to an electricity transmission and distribution system. See also "power grid."

Variable-speed wind turbines: Turbines in which the rotor speed increases and decreases with changing wind speeds. Sophisticated power control systems are required on variable-speed turbines to ensure that their power maintains a constant frequency compatible with the grid.

Volt (V): A unit of electrical force.

Voltage: The amount of electromotive force, measured in volts, between two points.

Watt (W): A unit of power.

Watt-hour (Wh): A unit of electricity consumption of one watt over the period of one hour.

Wind: Moving air. The wind's movement is caused by the sun's heat, the earth, and the oceans, which force air to rise and fall in cycles.

Wind energy: Energy generated by using a wind turbine to convert the mechanical energy of the wind into electrical energy. See also "wind power."

Wind generator: A wind energy conversion system designed to produce electricity.

Wind power: Power generated by using a wind turbine to convert the mechanical power of the wind into electrical power. See also "wind energy."

Wind power density: A useful way to evaluate the wind resource available at a potential site. The wind power density, measured in watts per square meter, indicates the amount of energy available at the site for conversion by a wind turbine.

Wind power class: A scale for classifying wind power density. There are seven wind power classes, ranging from 1 (lowest wind power density) to 7 (highest wind power density). In general, sites with a wind power class rating of 4 or higher are now preferred for large-scale wind plants.

Wind power plant: A group of wind turbines interconnected to a common utility system.

Wind resource assessment: The process of characterizing the wind resource and its energy potential for a specific site or geographical area.

Wind speed: The rate of flow of wind when it blows undisturbed by obstacles.

Wind speed profile: A profile of how the wind speed changes at different heights above the surface of the ground or water.

Wind turbine: A term used for a device that converts wind energy to electricity.

Wind turbine rated capacity: The amount of power a wind turbine can produce at its rated wind speed.

Windmill: A wind energy conversion system that is used primarily to grind grain. Windmill is commonly used to refer to all types of wind energy conversion systems.

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Produced for the U.S. Department of Energy by the
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DOE/GO-102008-2567 • July 2008

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Biomass Energy

Wood residues such as chips left from pulp and paper manufacturing and lumber mills, are economic sources of biomass fuel.

Biomass is plant matter such as trees, grasses, agricultural crops, and other living plant material. Biomass can be used in its solid form for heating applications or electricity generation, or it can be converted into liquid or gaseous fuels.
Biomass fuels are converted to heat and electricity with technologies similar to those used when converting fossil fuels, like coal, to heat and electricity. The mechanical device turns a generator that produces electricity. There are four primary types of biomass power systems: direct-fired, cofired, gasification, and modular systems.

The focus of this discussion is on biomass-fueled electricity generation systems. This discussion does not include landfill gas electricity generation. For more information on landfill gas, visit the U.S. Environmental Protection Agency (EPA) Landfill Methane Outreach Program.

Biomass used for energy purposes includes:

- Leftover materials from the wood products industry
- Wood residues from municipalities and industry
- Forest debris and thinnings
- Agricultural residues
- Fast-growing trees and crops
- Animal manures.

These materials can be renewable and

sustainable sources for fueling many of today's energy needs.

Next to hydropower, more electricity is generated from biomass than any other renewable energy resource in the United States. A key attribute of biomass is its availability on demand: much like fossil fuels, the energy is stored by nature in the biomass until it is needed. Technologies have now been developed that can generate electricity from the energy in biomass fuels at scales small enough to be used on a farm or in remote villages, or large enough to provide power for a small city.

Biomass is plentiful in various forms across the country. Certain forms of biomass are more plentiful in specific regions where climate conditions are more favorable for their growth. The most economical forms of biomass for generating electricity are residues. Residues are the organic by-products of food, fiber, and forest production such as sawdust, rice husks, wheat straw, corn stalks, and bagasse (the residue remaining after juice has been extracted from sugar cane).

Wood is the most commonly used biomass fuel for heat and power. The most economic sources of wood fuels are usually wood residues from manufacturers, discarded wood products diverted from landfills, and nonhazardous wood debris from construction and demolition activities. Generating energy with these materials can recoup the energy value in the material and avoid the environmental and monetary costs of disposal or open burning.

In the future, fast-growing energy crops may become the biomass fuels of choice. These energy crops will be carefully selected plants that are fast growing, drought resistant, and readily harvested to allow competitive prices when used as fuel.

Economic sources of biomass are also common near population and manufacturing centers where residues in the form of clean wood waste materials are available in large quantities. Examples are woody yard trimmings and discarded pallets and crates.

Biomass Power Systems

Most of today's biopower plants are direct-fired systems that are similar to most fossil fuel-fired power plants. The biomass fuel is burned in a furnace or boiler. The heat is used to produce high-pressure steam. This steam is introduced into a steam turbine where it flows over a series of aerodynamic turbine blades, causing the turbine to rotate. The turbine shares a common shaft with an electric generator, so as the steam flow causes the turbine to rotate, the electric generator is also turned and electricity is produced. The efficiency of direct-fired biopower facilities is typically 20%-24%.

Cofiring involves substituting biomass for a portion of coal in a power plant furnace. It is the most economic option for the near future to introduce new biomass power generation. Because much power plant equipment can be used without major modifications, cofiring is far less expensive than building a new biopower facility. Since the larger coal-fired facilities are usually more efficient than direct-fired biopower facilities, the biomass used in a cofiring application is converted to electricity with 33%-37% efficiency.

Biomass gasifiers operate by heating biomass in an environment where the solid biomass breaks down to form a flammable gas. This offers advantages over directly burning the biomass. The biogas can be cleaned and filtered to remove problem chemical compounds before it is burned. This will allow use of a wider range of biomass fuels. Also, the gas can be used in more efficient power generation systems called combined cycles, which combine gas turbines and steam turbines to produce electricity. The efficiency of gasification-based biopower systems can reach 60%.

Modular systems employ some of the same technologies mentioned above, but do so on a smaller scale that is more applicable to villages, farms, and small industry. These distributed energy systems are now under development and could be most useful in remote areas where biomass is abundant and electricity is scarce.

Biomass Benefits and Costs

As a renewable energy source, biopower offers an attractive alternative to conventional energy sources in the form of rural economic growth, national energy security, and environmental benefits. Although biopower is also generated through a combustion process, in most cases, it produces fewer emissions than conventional, fossil-fuel sources. It can actually improve environmental quality by offsetting fossil fuel use and related emissions and by using wastes that are creating land use problems.

Biopower growth can also create new markets and employment for farmers and foresters, many of whom currently face economic hardship. It can establish new processing, distribution, and service industries in rural communities.

The cost to generate electricity from biomass varies depending on the type of technology used, the size of the power plant, and the cost of the biomass fuel supply. Currently, the most economically attractive technology for biomass is cofiring. These projects require small capital investments per unit of power generation capacity. Cofiring systems range in size from 1 MW to 30 MW of biopower capacity. When low-cost biomass fuels are used, cofiring systems can result in payback periods as low as 2 years.

A typical coal-fueled power plant produces power for about $0.023/kilowatt-hour (kWh). Cofiring inexpensive biomass fuels can reduce this cost to $0.021/kWh, while the cost of generation would be increased if biomass fuels were obtained at prices at or above the power plant's coal prices. In today's direct-fired biomass power plants, generation costs are about $0.09/kWh. In the future, advanced technologies such as gasification-based systems could generate power for as little as $0.05/kWh. For comparison, a new combined-cycle power plant using natural gas can generate electricity for about $0.04-$0.05/kWh at fall 2000 gas prices.

For biomass to be economical as a fuel for electricity, the source of biomass must be located near to where it is used for power generation. This reduces transportation costs — the preferred system has transportation distances less than 100 miles. The most economical conditions are when the energy use is located at the site where biomass residues are generated, such as at a paper mill, sawmill, or sugar mill.

For more information, visit the DOE Biomass Program Web site.

The Biomass Research and Development Initiative, a multi-agency effort to coordinate and accelerate all federal biobased products and bioenergy research and development, is a good source of biomass news and information.

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Fuel Cell Technology Challenges

Cost and durability are the major challenges to fuel cell commercialization. However, hurdles vary according to the application in which the technology is employed. Size, weight, and thermal and water management are barriers to the commercialization of fuel cell technology. In transportation applications, these technologies face more stringent cost and durability hurdles. In stationary power applications, where cogeneration of heat and power is desired, use of PEM fuel cells would benefit from raising operating temperatures to increase performance. The key challenges include:

- **Cost.** The cost of fuel cell power systems must be reduced before they can be competitive with conventional technologies. Currently, the costs for automotive internal-combustion engine power plants are about \$25–\$35/kW; for transportation applications, a fuel cell system needs to cost \$30/kW for the technology to be competitive. For stationary systems, the acceptable price point is considerably higher (\$400–\$750/kW for widespread commercialization and as much as \$1000/kW for initial applications). For more information, see *Cost Analysis of Fuel Cell Systems for Transportation* (PDF 531 KB), presentation by the Fuel Cell Tech Team, TIAX LLC, October 20, 2004. Download Adobe Reader.

- **Durability and Reliability.** The durability of fuel cell systems has not been established. For transportation applications, fuel cell power systems will be required to achieve the same level of durability and reliability of current automotive engines [i.e., 5,000-hour lifespan (150,000 miles)] and the ability to function over the full range of vehicle operating conditions (40°C to 80°C). For stationary applications, more than 40,000 hours of reliable operation in a temperature at -35°C to 40°C will be required for market acceptance.

- **System Size.** The size and weight of current fuel cell systems must be further reduced to meet the packaging requirements for automobiles. This applies not only to the fuel cell stack, but also to the ancillary components and major subsystems (i.e., fuel processor, compressor/expander, and sensors) making up the balance of power system.
- **Air, Thermal, and Water Management.** Air management for fuel cell systems is a challenge because today's compressor technologies are not suitable for automotive fuel cell applications. In addition, thermal and water management for fuel cells are issues because the small difference between the operating and ambient temperatures necessitates large heat exchangers.
- **Improved Heat Recovery Systems.** The low operating temperature of PEM fuel cells limits the amount of heat that can be effectively utilized in combined heat and power (CHP) applications. Technologies need to be developed that will allow higher operating temperatures and/or more-effective heat recovery systems and improved system designs that will enable CHP efficiencies exceeding 80%. Technologies that allow cooling to be provided from the low heat rejected from stationary fuel cell systems (such as through regenerating dessiccants in a desiccant cooling cycle) also need to be evaluated.

A detailed list of the barriers to fuel cell commercialization and the technical targets to meet these challenges and guide the development of fuel cell technologies and systems for transportation, stationary, and portable applications are presented in the Fuel Cell Section of the *Program's Multi-Year Research* (PDF 678 KB), Development, and Demonstration Plan. Download Adobe Reader.

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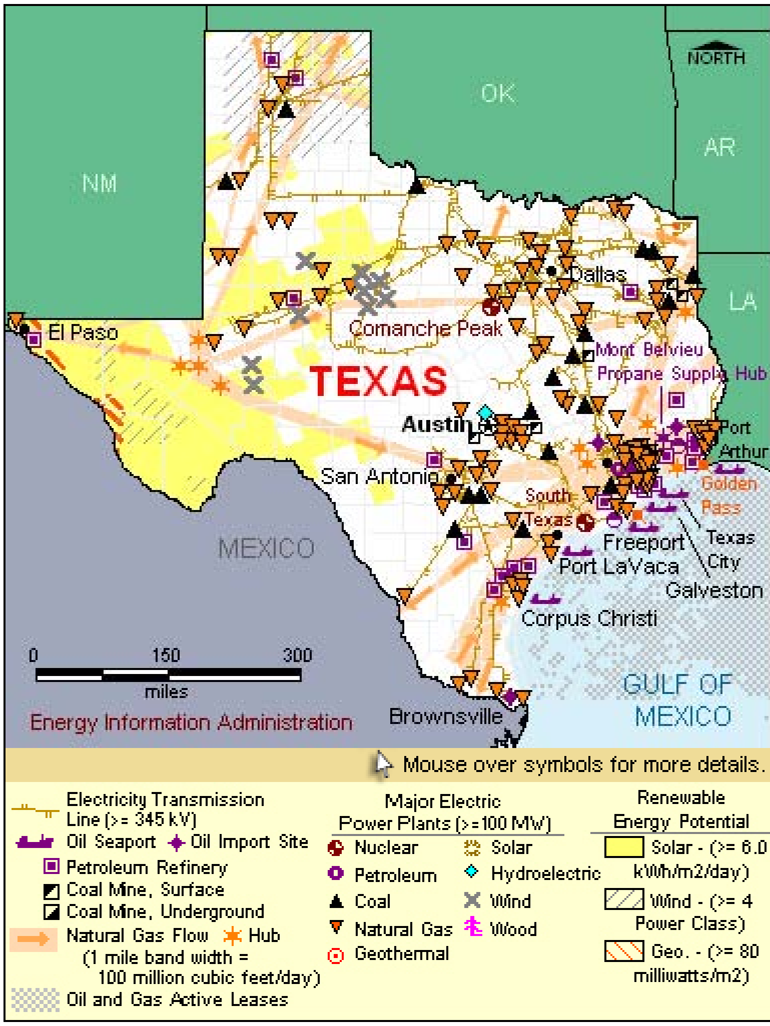

Texas Quick Facts

- Texas is the leading crude oil-producing State in the Nation (excluding Federal offshore areas, which produce more than any single State).
- The State's signature crude oil type, known as West Texas Intermediate (WTI), remains the major benchmark of crude oil in the Americas.
- Texas's 26 petroleum refineries can process nearly 4.8 million barrels of crude oil per day, and they account for more than one-fourth of total U.S. refining capacity.
- More than one-fourth of total U.S. natural gas production occurs in Texas, making it the Nation's leading natural gas producer.
- Texas also leads the Nation in wind-powered generation capacity; there are over 2,000 wind turbines in West Texas alone.
- Texas produces and consumes more electricity than any other State, and per capita residential use is significantly higher than the national average.

Overview

Resources and Consumption

Texas leads the Nation in fossil fuel reserves and in non-hydropower renewable energy potential. Texas crude oil reserves represent almost one-fourth of total U.S. oil reserves, and Texas natural gas reserves account for almost three-tenths of total U.S. natural gas reserves. Although Texas's oil reserves are found throughout the State in several geologic basins, the largest remaining reserves are concentrated in the Permian Basin of West Texas, which contains more than 20 of the Nation's top 100 oil fields. Similarly, deposits of natural gas are found in abundance in several Texas production basins, with the largest fields heavily concentrated in the East Texas Basin in the northeastern part of the State. Texas's fossil fuel reserves also include substantial deposits of lignite coal, found in narrow bands in the Gulf Coast region, and bituminous coal, found in north central and southwestern Texas.

Texas is also rich in renewable energy potential, including wind, solar, and biomass resources. Wind resource areas in the Texas Panhandle, along the Gulf Coast south of Galveston, and in the mountain passes and ridgetops of the Trans-Pecos offer Texas some of the greatest wind power potential in the United States. Solar power potential is also among the highest in the country, with high levels of direct solar radiation (suitable to support large-scale solar power plants) concentrated in West Texas. Due to its large agricultural and forestry sectors, Texas has an abundance of biomass energy resources. Although Texas is not known as a major hydropower State, substantial untapped potential exists in several river basins, including the Colorado River of Texas and the Lower Red.

Due to its large population and an energy-intensive economy, Texas leads the Nation in energy consumption, accounting for more than one-tenth of total U.S. energy use. Energy-intensive industries in Texas include aluminum, chemicals, forest products, glass, and petroleum refining.

Petroleum

Texas leads the United States in both crude oil production and refining capacity. Texas's first major oil boom began in 1901 with the discovery of the Spindle Top oil field in the upper Gulf Coast basin. Since then, major discoveries have been made in East Texas, West Texas, and offshore in the Gulf of Mexico. Texas oil production increased until 1972, when it peaked at more than 3.4 million barrels per day. Afterward, production declined rapidly, and in recent years Texas crude oil output has fallen to less than one-third of its 1972 peak.

Although Texas oil production is in decline, the State's signature crude oil type, known as West Texas Intermediate (WTI), remains the major benchmark of crude oil in the Americas. Because of its light consistency and low-sulfur content, the quality of WTI is considered to be high, and it yields a large fraction of gasoline when refined. Most WTI crude oil is sent via pipeline to Midwest refining centers, although much of this crude oil is also refined in the Gulf Coast region.

Texas's 26 petroleum refineries can process nearly 4.8 million barrels of crude oil per day, and they account for more than one-fourth of total U.S. refining capacity. Most of the State's refineries are clustered near major ports along the Gulf Coast, including Houston, Port Arthur, and Corpus Christi. These coastal refineries have access to local Texas production, foreign imports, and oil produced offshore in the Gulf of Mexico, as well as the U.S. government's Strategic Petroleum Reserve, which operates two large storage facilities in Bryan Mound and Big Hill, Texas. Many of Texas's refineries are sophisticated facilities that use additional refining processes beyond simple distillation to yield a larger quantity of lighter, higher value products, such as gasoline. Because of this downstream capability, Texas refineries often process a wide variety of crude oil types from around the world, including heavier, lower value varieties.

Refineries in the Houston area, including the Baytown refinery, the Nation's largest refinery, make up the largest refining center in the United States. From Houston, refined product pipelines spread across the country, allowing Texas petroleum products to reach virtually every major consumption market east of the Rocky Mountains. This network includes the Colonial Pipeline system (Koch), which is the largest petroleum product pipeline system in the United States and is vital for supplying markets throughout the South and East Coast.

Texas's total petroleum consumption is the highest in the Nation, and the State leads the country in consumption of asphalt and road oil, distillate fuel oil, jet fuel, liquefied petroleum gases (LPG), and lubricants. Texas LPG use is greater than the LPG consumption of all other States combined, due primarily to the State's active petrochemical industry, which is the largest in the United States. Four separate motor gasoline blends are required in Texas to meet the diverse air quality needs of different parts the State, including reformulated motor gasoline blended with ethanol required in the metropolitan areas of Houston and Dallas-Forth Worth. The agriculture-rich Texas Panhandle has several corn- and milo-based ethanol plants that are operational or under construction.

Natural Gas

Texas is the Nation's leading natural gas producer, accounting for more than one-fourth of total U.S. natural gas production. In the early days of Texas oil production, natural gas found with oil was largely considered a nuisance and was often flared (burned off) at the wellhead. Although some Texas cities and towns located near oil fields began using natural gas for energy, it was not until the State banned flaring after World War II that oil producers began to find new markets for natural gas. Two pipelines that once carried crude oil to the East Coast were converted to carry natural gas and a new natural gas pipeline to California was built, setting the stage for strong natural gas production growth in the 1950s and 60s. Texas natural gas production reached its peak in 1972 at more than 9.6 billion cubic feet of annual production. Since then, output has declined steadily to less than three-fifths of that level.

Today, an expansive network of interstate natural gas pipelines extends from Texas, reaching consumption markets from coast to coast, including those in California, the Midwest, the East Coast, and New England. Texas has 10 natural gas market hubs located in both East and West Texas, more than any other State, and its natural gas storage capacity is among the highest in the Nation. Most of Texas's 34 active storage facilities are depleted oil and gas fields converted for storage use, although many sites have also been developed in salt dome formations. These storage facilities allow Texas to store its natural gas production during the summer when national demand is typically lower and to ramp up delivery quickly during the winter months when markets across the country require greater volumes of natural gas to meet their home heating needs. However, due to the growing use of natural gas for electricity generation in the United States, Texas has occasionally withdrawn natural gas from storage during the summer months to help meet peak electricity demand for air-conditioning use.

Texas consumes more natural gas than any other State and accounts for about one-fifth of total U.S. natural gas consumption. Texas natural gas demand is dominated by the industrial and electric power sectors, which together account for more than four-fifths of State use. Because Texas demand is high, and because the State's natural gas infrastructure is well connected to consumption markets throughout the country, several companies have proposed building liquefied natural gas (LNG) import terminals along the Gulf Coast in Texas.

Coal, Electricity, and Renewables

Natural gas-fired power plants typically account for about one-half of the electricity produced in Texas and coal-fired plants account for much of the remaining generation. Although Texas produces a substantial amount of coal from 13 surface mines, including five of the 50 largest in the United States, the State relies on rail deliveries of subbitiminous coal from Wyoming for the majority of its supply. Nearly all of the coal mined in Texas is lignite coal, the lowest grade of coal, and all of it is consumed in the State, mostly in arrangements where a single utility operates both the mine and an adjacent coal-fired power plant. Although lower in energy content than other varieties of coal, lignite coal is also low in sulfur, an important consideration in the State's efforts to lower emissions. Texas consumes more coal than any other State and its emissions of carbon dioxide and sulfur dioxide are among the highest in the Nation.

Texas is a major nuclear power generating State. Two nuclear plants, Comanche Peak and South Texas Project, typically account for about one-tenth of the State's electric power production. Until the recent uprating (capacity improvement) of the Number 2 reactor at Palo Verde in Arizona, the two South Texas Project nuclear reactors were the largest in the Nation.

Although renewable energy sources contribute minimally to the Texas power grid, Texas leads the Nation in wind-powered generation capacity, and substantial new wind generation capacity is under construction in Texas. Texas surpassed California as the country's largest wind energy producer in 2006. Currently, there are over 2,000 wind turbines in West Texas alone, and the numbers continue to increase as development costs continue to drop and wind turbine technology improves. At 736 MW, the Horse Hollow Wind Energy Center in central Texas is the largest wind power facility in the world.

Texas produces and consumes more electricity than any other State. Despite large net interstate electricity imports in some areas, the Texas Interconnect power grid is largely isolated from the integrated power systems serving the eastern and western United States, and most areas of Texas have little ability to export or import electricity to and from other States. Texas per capita residential use of electricity is significantly higher than the national average, due to high demand for electric air-conditioning during hot summer months and the widespread use of electricity as the primary energy source for home heating during typically mild winter months.

Data

Economy

Population and Employment	Texas	U.S. Rank	Period
Population	24.3 million	2	2008
Civilian Labor Force	11.9 million	2	Dec-08
Per Capita Personal Income	$37,187	22	2007

Industry	Texas	U.S. Rank	Period
Gross Domestic Product by State	$1142.0 billion	2	2007
Land in Farms	129.9 million acres	1	2002
Market Value of Agricultural Products Sold	$14.1 billion	2	2002

Prices

Petroleum	Texas	U.S. Avg.	Period
Domestic Crude Oil First Purchase	$55.65/barrel	$53.7/barrel	Nov-08
No. 2 Heating Oil, Residential	—	$2.759/gal	Nov-08
Regular Motor Gasoline Sold Through Retail Outlets (Excluding Taxes)	$1.518/gal	$1.585/gal	Nov-08
State Tax Rate on Motor Gasoline (other taxes may apply)	$0.2/gal	$0.2159/gal	Aug-08
No. 2 Diesel Fuel Sold Through Retail Outlets (Excluding Taxes)	—	$2.318/gal	Nov-08
State Tax Rate on On-Highway Diesel (other taxes may apply)	$0.2/gal	$0.2214/gal	Aug-08

Natural Gas	Texas	U.S. Avg.	Period
Wellhead	$6.98/thousand cu ft	$6.37/thousand cu ft	2007
City Gate	$7.73/thousand cu ft	$7.75/thousand cu ft	Nov-08
Residential	$12.31/thousand cu ft	$13.73/thousand cu ft	Nov-08

Coal	Texas	U.S. Avg.	Period
Average Open Market Sales Price	$19.47/short ton	$26.20/short ton	2007
Delivered to Electric Power Sector	$ 1.68/million Btu	$ 2.17 /million Btu	Oct-08

Electricity	Texas	U.S. Avg.	Period
Residential	13.44 cents/kWh	11.86 cents/kWh	Oct-08
Commercial	10.58 cents/kWh	10.49 cents/kWh	Oct-08
Industrial	8.96 cents/kWh	7.24 cents/kWh	Oct-08

See more Price data for all States

Reserves & Supply

Reserves	Texas	Share of U.S.	Period
Crude Oil	5,122 million barrels	24.0%	2007
Dry Natural Gas	72,091 billion cu ft	30.3%	2007
Natural Gas Liquids	3,658 million barrels	40.0%	2007
Recoverable Coal at Producing Mines	737 million short tons	3.9 %	2007

Rotary Rigs & Wells	Texas	Share of U.S.	Period
Rotary Rigs in Operation	898	47.8%	2008
Crude Oil Producing Wells	144,660	28.9%	2007
Natural Gas Producing Wells	76,436	16.9%	2007

Production	Texas	Share of U.S.	Period
Total Energy	10,997 trillion Btu	15.5%	2006
Crude Oil	31,705 thousand barrels	21.4%	Sep-08

Natural Gas - Marketed	6,091,724 million cu ft	30.4%	2007
Coal	41,948 thousand short tons	NA	2007
Capacity	**Texas**	**Share of U.S.**	**Period**
Crude Oil Refinery Capacity (as of Jan. 1)	4,751,746 barrels/calendar day	27.2%	2008
Electric Power Industry Net Summer Capability	101,938 MW	10.2%	2007
Net Electricity Generation	**Texas**	**Share of U.S.**	**Period**
Total Net Electricity Generation	30,624 thousand MWh	9.6%	Oct-08
Petroleum-Fired	5 thousand MWh	0.3%	Oct-08
Natural Gas-Fired	14,729 thousand MWh	20.3%	Oct-08
Coal-Fired	11,736 thousand MWh	7.7%	Oct-08
Nuclear	2,352 thousand MWh	3.7%	Oct-08
Hydroelectric	68 thousand MWh	0.4%	Oct-08
Other Renewables	1,393 thousand MWh	14.3%	Oct-08
Stocks	**Texas**	**Share of U.S.**	**Period**
Motor Gasoline (Excludes Pipelines)	9,185 thousand barrels	15.1%	Nov-08
Distillate Fuel Oil (Excludes Pipelines)	13,891 thousand barrels	13.7%	Nov-08
Natural Gas in Underground Storage	580,789 million cu ft	7.7%	Nov-08
Petroleum Stocks at Electric Power Producers	1,081 thousand barrels	2.7 %	Oct-08
Coal Stocks at Electric Power Producers	15,567 thousand tons	9.9%	Oct-08

Production Facilities	**Texas**
Major Coal Mines	Jewett Mine/Texas Westmoreland Coal Co. • Beckville Strip/Luminant Mining • South Hallsville No. 1/Sabine Mining Co. • Three Oaks/Luminant Mining • Oak Hill Strip/Luminant Mining
Petroleum Refineries	Age Refining Inc (San Antonio) • Alon USA Energy Inc (Big Springs) • BP Products North America Inc (Texas City) • Citgo Refining & Chemical Inc (Corpus Christi) • ConocoPhillips Company (Sweeny) • Deer Park Refining LTD Partnership (Deer Park) • Delek Refining LTD (Tyler) • Equistar Chemicals LP (Channelview) • ExxonMobil Refining & Supply Co (Baytown) • ExxonMobil Co (Beaumont) • Flint Hills Resources LP (Corpus Christi) • Houston Refining LP (Houston) • Marathon Petroleum Co LLC (Texas City) • Motiva Enterprises LLC (Port Arthur) • Pasadena Refining Systems Inc (Pasadena) • Premcor Refining Group Inc (Port Arthur) • South Hampton Resources Inc (Silsbee) • Total Petrochemicals Inc (Port Arthur) • Trigeant LTD (Corpus Christi) • Valero Energy Corporation (Sunray) • Valero Energy Corporation (Three Rivers) • Valero Refining Co Texas LP (Corpus Christi) •Valero Refining Co Texas LP (Houston) • Valero Refining Co Texas LP (Texas City) • Western Refining Company LP (El Paso) • WRB Refinging LLC (Borger)
Major Non-Nuclear Electricity Generating Plants	W A Parish (NRG Texas LLC) • Cedar Bayou (NRG Texas LLC) • Martin Lake (TXU Generation Co LP) • P H Robinson (NRG Texas LLC) • Sabine (Entergy Gulf States Inc)
Nuclear Power Plants	South Texas Project (STP Nuclear Operating Co) • Comanche Peak (TXU Generation Co LP)

See more Reserves and Supply data for all States

Distribution & Marketing

Distribution Centers	Texas
Oil Seaports/Oil Import Sites	Houston • Port Arthur • Corpus Christi • Texas City • Freeport • Beaumont • Brownsville • Galveston • Port LaVaca
Natural Gas Market Centers	Agua Dulce Hub (Production Center) • Carthage Hub (Market Hub) • Katy Hub (Market Hub) • Katy Storage Center (Market Hub) • Moss Bluff Hub (Market Hub) • Spindletop Storage Hub (Market Hub) • Waha (Lonestar) Hub • Waha (Encina) Hub • Waha (DEFS) Hub • Waha (EPGT) Texas Hub.

Major Pipelines	Texas
Crude Oil	All American • Amoco • Arco • Camden • Celex • Chevron • Coastal • Conoco • Duke • EOTT Energy • ETML • Exxon • Farmland • Fina • Genesis • Jayhawk • Koch • Matador • Mobil • Natural Gas Clearinghouse • Pactex • Phillips • Pride • Scurlock-Permian • Seaway • Shell • Sun • Texaco • Texas-New Mexico • Ultramar-Diamond Shamrock • Unocal • West Texas Gulf.
Petroleum Product	ATA • Chevron • Citgo • Coastal • Conoco • DSE • Explorer • Exxon • Koch • Longhorn • Magellan • Mobil • Navajo • Phillips • Pride • Shell • Sigmor • SFPP • TEPPCO • Texaco • River • STOP • Trust • UDS.
Liquefied Petroleum Gases	Chevron • Coastal • Conoco • Dettco • Dixie • Dow • DSE • Duke • Dynegy • Exxon • Highlands • Koch • MAPCO • Mitchell • Mobil • NuStar • Oxy • Phillips • Pride • Rio Grande • Sea Gull • Seadrift • Seminole • TEPPCO • Texas Eastman • Tejas • UPR • Valero.
Interstate Natural Gas Pipelines	ANR Pipeline Co. • Centerpoint Energy Gas Transmission Co. • Colorado Interstate Gas • El Paso Natural Gas Co. • Enbridge Pipelines (East Texas) • Florida Gas Transmission Co. • Gulf South Pipeline Co. • KM Interstate Gas Co. • Mississippi River Transmission Corp. • Natural Gas Pipeline Company of America • Northernal Natural Gas Co. • Oneok Westek Pipeline Co. • Oneok Gas Transportation Systems • Panhandle Eastern Pipeline Co. • Southern Natural Gas Co. • Southern Star Central Gas Pipeline Co. • Tennessee Gas Pipeline Co. • Texas Eastern Transmission Corp. • Texas Gas Transmission Co. • Transcontinental Gas Pipeline Co. • Transok Inc. • Transwestern Pipeline Co. • Trunkline Gas Co.

Fueling Stations	Texas	Share of U.S.	Period
Motor Gasoline	13,760	8.4%	2007
Liquefied Petroleum Gases	485	23.0%	2009
Compressed Natural Gas	17	2.2%	2009
Ethanol	36	2.1%	2009
Other Alternative Fuels	59	4.7%	2009

See more Distribution and Marketing data for all States

Consumption

per Capita	Texas	U.S. Rank	Period
Total Energy	502 million Btu	5	2006
by Source	**Texas**	**Share of U.S.**	**Period**
Total Energy	11,744 trillion Btu	11.8%	2006
Total Petroleum	1,199,918 thousand barrels	15.9%	2006
Motor Gasoline	290,606 thousand barrels	8.6%	2007

	Texas	Share of U.S.	Period
Distillate Fuel	141,350 thousand barrels	9.3%	2006
Liquefied Petroleum Gases	422,776 thousand barrels	56.4%	2006
Jet Fuel	75,409 thousand barrels	12.7%	2007
Natural Gas	3,515,902 million cu ft	15.3%	2007
Coal	103,763 thousand short tons	9.3%	2006
by End-Use Sector	**Texas**	**Share of U.S.**	**Period**
Residential	1,579,620 billion Btu	7.6%	2006
Commercial	1,375,315 billion Btu	7.8%	2006
Industrial	5,926,088 billion Btu	18.4%	2006
Transportation	2,863,361 billion Btu	9.9%	2006
for Electricity Generation	**Texas**	**Share of U.S.**	**Period**
Petroleum	NM	NA	Oct-08
Natural Gas	121,110 million cu ft	21.1%	Oct-08
Coal	8,054 thousand short tons	10.0%	Oct-08
for Home Heating (share of households)	**Texas**	**U.S. Avg.**	**Period**
Natural Gas	43%	51.2%	2000
Fuel Oil	0%	9.0%	2000
Electricity	49%	30.3%	2000
Liquefied Petroleum Gases	6%	6.5%	2000
Other/None	2%	1.8%	2000

See more Consumption data for all States

Environment

Special Programs	Texas		
Clean Cities Coalitions	The Alamo Area (San Antonio) • Central Texas (Austin) • Dallas/Ft. Worth • East Texas • Houston-Galveston • South East Texas (Beaumont-Port Arthur) •		
Alternative Fuels	**Texas**	**Share of U.S.**	**Period**
Alternative-Fueled Vehicles in Use	92,968	15.7%	2006
Ethanol Plants	0	0.0%	2008
Ethanol Plant Capacity	0 million gal/year	0.0%	2008
Ethanol Use in Gasohol	28,734 thousand gal	0.8%	2004
Electric Power Industry Emissions	**Texas**	**Share of U.S.**	**Period**
Carbon Dioxide	257,552,160 metric tons	10.5%	2006
Sulfur Dioxide	558,355 metric tons	5.9%	2006
Nitrogen Oxide	260,052 metric tons	6.8%	2006

See more Environment data for all States

— = No data reported; NA = Not available; W = Withheld to avoid disclosure of individual company data.
NM = Not meaningful due to large relative standard error or excessive percentage change.

Update on Feb. 12, 2009

New statistics for 2009:
• Alternative fuel stations
New statistics for 2007:
• Consumption of motor gasoline and jet fuel

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  tables that provide time series data from 1990 forward for key electricity indicators by State
- State Renewable Electricity Profiles
  tables that provide data for the most recent year on capacity and generation of electricity from renewable sources
- State Compendium of Nuclear Power Plants
  State-by-State reports on the nuclear industry
- Natural Gas Residential Choice Programs
  written overviews of the status of natural gas industry restructuring in each State, focusing on the residential customer class
- Status of Electricity Restructuring by State
  annotated map showing details of the status of electricity restructuring in each State
- Regional Energy Profiles
  reports and maps that explore regional variations in U.S. energy consumption

Electric Power Annual

Electric Power Annual with data for 2007
Report Released: January 21, 2009
Next Release Date: October 2009

Electric Power Industry 2007: Year in Review

Overview

In 2007, average retail electricity prices increased 2.6 percent from 8.9 to 9.1 cents per kilowatthour (kWh) This followed a 3-year period during which average fossil fuel prices for electricity generation increased a cumulative 30.2 percent. As fuel prices increased 30.2 percent, the National average retail price of electricity increased 17.0 percent from 7.6 cents per kWh in 2004 to 8.9 per kWh in 2006. Fossil fuel prices increased an additional 7.0 percent in 2007, contributing to the 2.6 percent average retail electricity rate.

Both the number of residential and commercial customers increased 1.2 percent over 2006 levels. Residential and commercial customer growth, along with a modest increase in average consumption per residential and commercial customer, resulted in a 3.0 percent increase in residential electricity sales and a 2.8 percent increase in commercial electricity sales in 2007. Residential and commercial sales accounted for 69.5 percent of total retail sales. When all sales to ultimate consumers are considered (e.g., residential, commercial, industrial, transportation, other and direct use), electricity sales increased by 2.8 percent in 2007. In 2006, total sales increased only 0.2 percent from the prior year.

In response to the 2.8 percent increase in sales to ultimate customers, electric power generation increased 2.3 percent, from 4,065 million megawatthours (MWh) in 2006 to 4,157 MWh in 2007. The remaining energy requirements were met by imports from Canada and Mexico. Although electric power generation increased by 2.3 percent in 2007, net summer capacity increased by 8,673 megawatts (MW) or 0.9 percent. Since more than half of the new capacity was non-dispatchable wind capacity, the 2.3 percent increase in net generation was achieved primarily through the increased performance of existing coal-fired, natural gas-fired and nuclear capacity. All three of these types of capacity set net production levels, and increased average capacity factors, in 2007.

In 2007, for the first time, renewable energy sources, other than conventional hydroelectric capacity, accounted for the largest portion of capacity additions. Total net summer capacity increased 8,673 MW in 2007. Wind capacity accounted for 5,186 MW of this new capacity. Natural gas-fired generation accounted for 4,582 MW. Two new coal-fired plants with summer capacity totaling 1,354 MW were placed in service in 2007. However, retirements and

(entire report also available in printer-friendly format)

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downward adjustments to existing capacity resulted in a 217 MW net reduction in coal-fired capacity.

Summer peak demand (noncoincident) fell from 789,475 MW in 2006 to 782,227 MW in 2007. Winter peak demand (noncoincident), which is always smaller than summer peak demand, decreased in 2007, falling a modest 0.5 percent from 640,981 MW in 2006 to 637,905 in 2007.

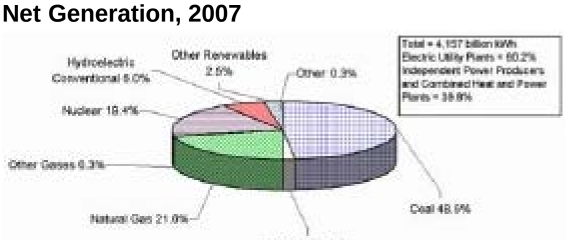
While the National average retail price for electricity for all customer classes increased by 2.6 percent to an average of 9.1 cents per kilowatthour, regional variations were significant. For example, the average retail price in the West South Central Census Division declined in 2007, whereas the average price increased in all other Census Divisions. The East North Central Census Division experienced the largest average price increase at 6.9 percent. This increase was primarily the result of the lifting of rate caps in Illinois that were put in place with retail restructuring in 1997. Average prices increased by 4.0 percent in the New England Census Division, 3.4 percent in the East South Central Census Division and 3.3 percent in the Middle Atlantic Census Division.

Unlike 2006, when carbon dioxide, sulfur dioxide and nitrogen oxides emission declined, carbon dioxide emissions from conventional electric generation and combined heat and power plants increased 2.3 percent in 2007. Sulfur dioxide and nitrogen oxides decreased 5.1 percent and 3.9 percent, respectively. Since 1997, sulfur dioxide and nitrogen oxides emission have been reduced by 32.9 percent and 43.8 percent, respectively.

Generation

Net generation of electric power increased 2.3 percent in 2007, to 4,157 million megawatthours (MWh) from 4,065 million MWh in 2006 (Figure ES1). According to the Bureau of Economic Analysis, the U.S. real gross domestic product increased 2.0 percent in 2007.[1] The Federal Reserve Board reported a 1.7 percent increase in total industrial production.[2] Thus, the increase in electricity demand corresponded with economic growth in 2007. Weather also appears to have been a contributing factor to electricity demand. According to the National Oceanic and Atmospheric Administration (NOAA), heating degree days in 2007 were 6.5 percent higher and cooling degree days were 2.2 percent higher than they were in 2006. Thus, the combination of moderate economic growth and weather-related electricity demand appears to have contributed to the 2.3 percent increase in net generation, as compared to the relatively flat 0.2 percent growth observed in 2006.

Figure ES 1. US Electric Power Industry Net Generation, 2007



Sources: Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and predecessor form(s) including Energy Information Administration, Form EIA-906, "Power Plant Report;"

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and Form EIA-920, "Combined Heat and Power Plant Report."

The three primary energy sources for generating electric power in the United States are coal, natural gas, and nuclear energy. These three sources consistently provided between 84.6 and 89.5 percent of total net generation during the period 1997 through 2007. Petroleum's relative share of total net generation was unchanged in 2007 from 2006 at 1.6 percent. Conventional hydroelectric power continues to decline as a share of total net generation. In 2007, conventional hydroelectric generating capacity accounted for 6.0 percent of total net generation, as compared to 10.2 percent in 1997. Renewable energy sources, excluding conventional hydroelectric generation, contributed 2.5 percent of total net electric generation in 2007. This marks the fourth consecutive year in which renewables' share of total net generation has increased.

In 2007, electricity generation from coal-fired capacity increased 1.3 percent, reversing the decline from 2005 to 2006. Coal-fired generation increased from 1,991 million MWh in 2006 to 2,016 million MWh in 2007. This is a new record, exceeding the previous all-time high of 2,013 million MWh set in 2005. The record level of coal-fired generation reflects a one percentage point increase in the average capacity factor of coal-fired generation to 73.6 percent. Additionally, two coal-fired power plants located in the Pacific Northwest returned to service during 2007. The Boardman Plant, located in Oregon returned to service in May 2006 following a series of outages that began in October 2005. Net generation from the Transalta Centralia Generating Plant, located in Washington State, increased in 2007 following a reduced level of production in 2006, when the plant conducted a test burn of Powder River Basin coal. Coal-fired electricity production was further enhanced by the commencement of commercial operations at the Walter Scott, Jr. Energy Center Unit No. 4, located in Council Bluffs, Iowa (923 MW nameplate rating) and the Cross Generating Station No. 3 located in South Carolina (591 MW nameplate rating).

In spite of setting a record level for generation in 2007, coal's share of total net generation continued its downward trend in 2007. It accounted for 48.5 percent of total net generation in 2007 as compared to 49.0 percent in 2006 and 52.8 percent in 1997. Nevertheless, it remains the primary source of baseload generation. The decline in coal's share of total net generation in 2007 was attributable to continued increase in the share of total net generation produced by natural gas-fired and nuclear capacity, as well as renewable sources, other than conventional hydroelectric capacity.

Net generation from natural gas-fired capacity increased 9.8 percent, from 816 million MWh to 897 million MWh in 2007. This was the second largest 1-year increase in natural-gas fired generation since the 10.8 percent increase that occurred in 1998. Natural gas-fired generation accounted for 21.6 percent of total net generation in 2007 as compared to 20.1 percent in 2006. For the second consecutive year, natural-gas fired generation was the second leading contributor to total net generation, surpassing nuclear generation, which historically was the second leading source of total net generation after coal.

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Net generation at nuclear plants increased 2.4 percent in 2007 to 806 million MWh. Between 1996 and 2007, nuclear generation ranged from an 18.0-20.6 percent share of total net generation with an annual average growth in net generation of 1.6 percent from 1996 through 2007, despite the fact that no new nuclear units have been constructed. The continued growth in nuclear generation is due to improved capacity utilization, and in 2007, the resumption of commercial operations at the Tennessee Valley Authority's Browns Ferry Unit 1 after a 22-year shutdown. Since 1996, average capacity factors for nuclear plants increased from 76.2 percent to 91.8 percent (Table A6). In 2007, nuclear power plants operated at their highest average capacity factor, once again setting a record for net generation. In past years, growth in nuclear generation was the result of both improved capacity factors and uprates of existing plants. In 2007, the increase in nuclear generation appears to be primarily a function of improved plant performance. In 2007, nuclear plant operators reported a 47 MW increase in net winter capability and a 68 MW decrease in net summer capability. This is the first year since 1999 in which the net summer capability of nuclear plants declined, a significant departure from the annual increases in net summer capacity of existing nuclear plants that occurred between 1999 and 2006. During this period net summer capability of existing nuclear plants increased by 2,293 MW, which equates to an average annual increase of 418 MW of net summer capability.

Net generation from conventional hydroelectric plants declined 14.4 percent from 289 million MWh in 2006 to 248 million MWh in 2007. The decline in conventional hydroelectric generation is consistent with the drought conditions, which according to the National Climatic Data Center (NCDC) prevailed over the West and Southeast for much of the year. According to NCDC, evaporation caused by above normal summer temperatures exacerbated drought conditions in these regions. Moreover, precipitation was below average in the Southeast and the mountain snowpack in the Rocky Mountain and Western States was significantly below normal levels.[3]

Petroleum-fired generation increased 2.5 percent, to 66 million MWh. Its share of total net generation remained unchanged from 2006 at 1.6 percent.

Net generation produced by renewable energy sources, excluding hydroelectric generation, grew by 9.0 percent as compared to 10.5 percent growth in 2006. Renewable energy accounted for 2.5 percent or 105 million MWh of total net generation in 2007. Wood and wood derived fuels accounted for 39 million MWh or 0.9 percent of total net generation. Wind generation was the second largest renewable energy source, contributing 34 million MWh or 0.8 percent of total net generation in 2007. Geothermal power plants supplied 15 million MWh of net generation and other biomass 17 million MWh. Each of these renewable sources accounted for approximately 0.4 percent of total net generation in 2007. In 2007, wood and wood derived fuels continued to be the largest sources of renewable generation, accounting for 37.1 percent of total net renewable generation, excluding conventional hydroelectric generation. Wind generation is rapidly gaining a larger share of total renewable generation. In 2007, wind accounted for 32.7 percent of total net generation from non-hydroelectric renewable sources, as compared to 4.3 percent in 1997. The annual growth in solar thermal and photovoltaic generation has

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been sufficient for this renewable source to account, on average, for 0.5 percent of all non-hydroelectric renewable energy. Wood and wood derived fuels and geothermal have maintained fairly stable output levels averaging 38 million MWh and 15 MWh per year, respectively. Other biomass generation has declined from a 23 million MWh peak in 2000 to 17 million MWh in 2007.

Generation from other gases (refinery gases, blast furnace gas, etc.) and other miscellaneous sources accounted for the remaining net generation. Net generation from these sources declined from 27 million MWh in 2006 to 26 million MWh. Finally, net energy requirements for pumped-storage hydroelectric generation increased 0.3 million MWh in 2007.

Fossil Fuel Stocks at Electric Power Plants

End-of-year coal stocks for 2007 increased 7.3 percent from 141 million tons to 151 million tons. The build in coal stocks in 2007 was considerably less than the 39.4 percent increase that occurred in 2006. This appears to be the result of the increase in coal-fired generation relative to 2006, and a reduction in coal purchases in response to rising coal prices. While coal consumption at electric power plants increased 16 billion tons receipts declined by 25 billion tons in 2007. The increase in end-of-year stocks is consistent with the finding in the North American Electric Reliability Corporation’s (NERC) 2007/2008 Winter Reliability Assessment that power plant inventories were ahead of historical normal levels, with inventory levels approaching 45 days as compared to 40 days.[4] While NERC concluded that coal stocks are satisfactory, it has identified longer-term market risks that could impact the security of supply in the long-run. These include capacity constraints on rail lines, particularly from the Powder River Basin and rolling stock shortages. NERC also indicated that rising coal prices may cause power plant owners to reduce on-site fuel supply in order to minimize carrying costs.[5]

Inventories of petroleum decreased from 51.6 million barrels at the end of 2006 to 47.2 million barrels by year end 2007. The decline in petroleum inventories is a function of increased consumption caused by the 2.5 percent increase in petroleum-fired generation, and a 12.6 million barrel reduction in petroleum receipts at power plants, which is likely attributable to the 13.1 percent increase in petroleum prices.

Capacity

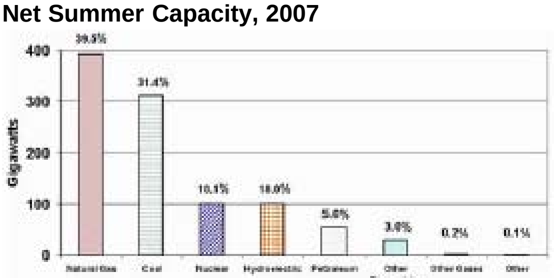
Total U.S. net summer generating capacity as of December 31, 2007 was 994,888 MW, an increase of 1.0 percent from January 1, 2007 (Figure ES2). During the year, net summer generating capacity increased 8,673 MW, after accounting for retirements, deratings (i.e., a reduction in power plant generating capability) and other adjustments. For the first time, non-hydroelectric, renewable energy capacity additions exceeded total fossil fuel capacity additions. Natural gas-fired generating units accounted for 4,582 MW or 52.8 percent of net summer capacity additions.

On December 31, 2007, natural gas-fired generating capacity represented 392,876 MW or 39.5 percent of total net summer generating capacity (Figure ES2). Although new natural gas-fired combined-cycle plants produce electricity more efficiently than older fossil-fueled plants, high natural gas prices can work against full utilization of these plants if such prices adversely affect economic dispatch. Since 1996, net summer natural gas-fired capacity has increased 218,741 MW net of retirements and adjustments. Natural gas capacity additions during this period were virtually equal to the 218,998 MW total increases in net summer capability. During this period coal, petroleum and nuclear capacity decreased by a net 17,612 MW, along with 783 MW of non-hydroelectric renewable capacity. That is, after additions and uprates, net summer capability associated with these types of resources collectively declined over the past 10 years. Since 1997, natural gas-fired additions in effect offset net retirements across all fuel types, with the cumulative net increase in capacity equal to 14,760 MW of non-hydroelectric, renewable capacity and 3,111 MW of other gases, hydroelectric and other capacity.

Petroleum-fired capacity totaled 56,068 MW, down 2,029 MW from 2006. Petroleum-fired capacity accounted for 5.6 percent of all generating capacity.

Coal-fired generating capacity remained essentially unchanged at 312,738 MW, or 31.4 percent of total generating capacity. This share of total capacity represents a slight decline from 2006. Retirements of and other adjustments to existing coal-fired capacity reported by operators in 2007 exceeded the 1,354 MW of net summer capacity of the 2 new plants placed in service by 1,514 MW. Since 1996, net summer coal-fired capacity has declined 644 MW after accounting for new additions, upgrades and other adjustments reported by operators. Nevertheless, net generation from the Nation's coal-fired plants continues to increase due to gains in operating efficiency.

Figure ES 2. U.S. Electric Power Industry Net Summer Capacity, 2007



Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Wind generating capacity totaled 16,515 MW in 2007, which amounts to a 45.8 percent increase over the 11,329 MW in operation during 2006. Of the 8,673 MW total increase in net summer capability in 2007, wind generating capacity accounted for 5,186 MW. Texas continues to lead the Nation in wind power development with 1,752 MW of new wind capacity placed in service in 2007, increasing its share of Nation's wind capacity currently in operation to 27.2 percent. California has the second highest share of total installed wind generating capacity at 2,312 MW. The remainder of the top five wind producing States includes Iowa at 7.1 percent, Washington at 7.0 percent and Minnesota at 6.9 percent of the Nation's total installed wind generating capacity. Collectively, 10,273 MW or 62.2 percent of total wind generating capacity is located in these 5 States. Wind power development has accelerated in Colorado, Illinois, Oklahoma and Oregon with the addition of 1,794 MW of capacity. Over the last three years 10,059 MW of wind generating capacity has been placed in service. The electric generating capacity from non-hydroelectric renewable energy sources increased 24.7 in 2007. Wind capacity accounted for 87.1 percent of the 5,596 MW of non-hydro renewable energy sources placed in service in 2007.

Nuclear net summer generating capacity totaled 100,266 MW or 10.1 percent of total capacity. Uprates totaling 179 MW of nameplate capacity were made at the Duane Arnold Energy Center and R. E. Ginna plant. However, nuclear plant operators reported that net summer capacity declined by 68 MW and net winter capacity increased by 47 MW. Thus, continued improvement in plant performance was the primary factor supporting the increase in nuclear generation in 2007, with a large share of that increase stemming from the resumption of output from the Browns Ferry 1 unit in Alabama, which returned to service in June 2007 after a two-decade hiatus.

Conventional hydroelectric generating capacity accounted for 7.8 percent of total capacity with a summer net generating capacity of 77,885 MW. Pumped storage hydroelectric generating capacity totaled 21,886 MW. Combined, conventional and pumped storage generating capacity accounted for 10.0 percent of total capacity. Like coal and nuclear, hydroelectric generating capacity has remained relatively unchanged over the last 10 years.

The year 2007 was the fourth year in which EIA has collected data on distributed and dispersed generating facilities. In 2004, 9,579 MW of dispersed and distributed generators were reported. By year-end 2007, the amount of dispersed and distributed generators has increased to 20,999 MW.[6] Of this total, 59.1 percent is internal combustion capacity. While internal combustion capacity is the predominant form of dispersed and distributed generating capacity, wind capacity has grown significantly. In 2004, there were 0.1 MW of dispersed and distributed wind capacity. As of 2007, there is 1,462 MW.

As of December 31, 2007, reported planned additions scheduled to start commercial operation between 2008 and 2012 have total nameplate capacity of 92,996 MW. This compares with 87,109 MW of planned capacity reported on December 31, 2006, for the 5-year period through 2011. The data also show that over the next two years there will be a significant increase in planned additions relative to the past 2 years, if additions are completed as planned. In 2006 and 2007, the industry added 28,381 MW of nameplate capacity. Planned capacity additions projected to be placed in service during calendar years 2008 and 2009 total 44,701 MW. Given the recent turmoil in financial markets, which has affected both the cost and access to capital, and slowdown in economic activity, it is likely that some of this capacity will be deferred. The data also reveal a shift in the fuel mix. New coal-fired and renewable energy sources are projected to play a more significant role over the next 5 years. The industry reports that it is planning to add 23,347 MW of coal-fired capacity over the next 5 years. In terms of net summer capacity, planned coal-fired additions account for 25.7 percent of planned additions over the next 5 years, which is an amount equivalent to 6.9 percent of existing coal-fired capacity. Renewable energy sources, excluding hydroelectric, are 19.5 percent of planned new net summer capacity. Natural gas-fired capacity is projected to be the dominant primary fuel for electricity generation with planned additions totaling 48,100 MW, or 51.7 percent of all planned additions for the 5-year period.

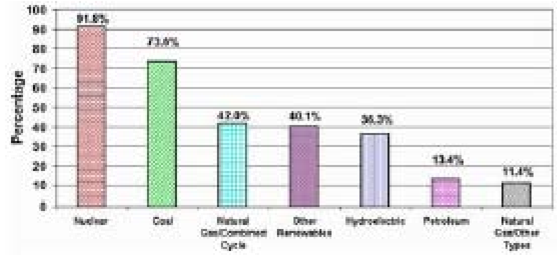
As expected, nuclear and coal-fired generation have the highest average capacity factors at 91.8 percent and 73.6 percent, respectively (Figure ES3). This is consistent with the economies of scale that these forms of capital intensive and energy efficient generation provide to serve energy requirements. Accordingly, coal and nuclear capacity serve baseload energy requirements, which are reflected by higher average capacity factors relative to other forms of generation. The average capacity factor for coal-fired generation reflects a one percentage point increase over the 72.6 percent average capacity factor achieved in 2006. The average capacity factor for nuclear generation increased from 89.6 percent to 91.8 percent. This compares to the 89.7 percent average over the past five years and the low of 72.0 percent that occurred in 1997. Because the industry continues to rely on new combined cycle natural gas generation to meet rising demand, average capacity factors for natural gas generation have been calculated for both combined cycle generation and simple cycle natural gas generation.[7] In 2007, the capacity factor for combined cycle generating capacity factor was 42.0 percent. In 2003, the average capacity factor for combined cycle generation was 33.5 percent. The 8.4 percentage point improvement in the average capacity factor reflects both the increased reliance on combined cycle generation to meet energy requirements and further efficiency gains in combined cycle generation technology. In 2007 the average capacity factor for simple cycle natural gas-fired generation was 11.4 percent.

The more recent emphasis placed on wind capacity, which is not a dispatchable resource, is reflected in the reduced performance of renewable resources in aggregate as measured by a composite capacity factor. Renewable generation other than hydroelectric had a 40.1 percent capacity factor in 2007. In 1999, the average capacity factor for other renewable generation was 56.9 percent. The continuous decline in the average capacity factor for all non-hydroelectric renewable resources is consistent with the significant growth of wind capacity relative to other forms of renewable electricity generation. Wind is a non-dispatchable resource that is available for generation subject to prevailing wind conditions. It is expected to have a lower capacity factor relative to solid and liquid biomass generating capacity (e.g., landfill gas, municipal solid waste, black liquor and wood waste solids), which have greater continuity in the receipt of primary fuel supply for electricity generation. The primary factor limiting the capacity factor of biomass generating capacity is its position in the economic dispatch order relative to load.

Wind generating capacity exceeds all forms of non-hydroelectric renewable energy sources. In 2007, wind capacity accounted for 16,515 MW of net summer capacity. Wood and wood derived fuels contributed the second largest share of renewable capacity at 6,704 MW. The growth of this source of renewable energy has fluctuated between net increases and decreases in capacity over time. Since 1996, the amount of wood and wood derived fuels capacity has fallen by 104 MW. Wind generating capacity is the fastest growing renewable energy source. In 2007, 5,186 MW of new capacity was placed in service increasing total wind capacity to 16,515 MW. New wind capacity accounted for 87.1 percent of the 5,956 MW of total renewable capacity (other than conventional hydroelectric capacity) placed in service in 2007. As a result the average capacity factor for renewable energy declined as expected.

Conventional hydroelectric generation had an average capacity factor of 36.3 percent in 2007 as compared to 42.4 percent in 2006. The decline in conventional hydroelectric generation is a result of drought conditions in the Southeast, Rocky Mountains and West.

Figure ES 3. Average Capacity Factor by Energy Source, 2007



Source: Energy Information Administration, Form EIA-860, “Annual Electric Generator Report;” Form EIA-923, "Power Plant Operations Report.”

Fuel Switching Capacity

The total amount of net summer capacity reporting natural gas as the primary fuel in 2007 was 392,876 MW, of which 123,862 MW (31.5 percent) reported a current operational capability to switch to fuel oil as an alternative fuel. This means that the capacity had in working order all necessary equipment, including fuel storage, to switch from gas to petroleum-fired operation. However, most of this capacity is subject to environmental regulatory limits on the use of oil, such as restrictions on how many hours per year a unit is allowed to burn oil. Of the 123.862 MW of gas-fired capacity that reported the ability to switch to oil, only 39,817 MW (32.1 percent) reported no environmental regulatory constraints or other factors that would limit oil-fired operations.

“Switchable” capacity is spread across the major generating technologies. Combustion turbine peaking units account for 43.7 percent (54,135 MW) of this capacity. Steam-electric generators (33,553 MW) and combined cycle units (35,270 MW) account for 27.1 percent and 28.4 percent, respectively. Internal combustion engines make up the remaining 0.7 percent. When running on fuel oil the net summer capability of the 33,553 MW of steam-electric generating capacity is 18,245 MW. The 54,135 MW of gas turbine capacity has an achievable net summer capacity of 15,358 MW when running on oil.

Over time, the achievable net summer capacity for natural-gas fired capacity when run on fuel oil has declined. Through 1974, the net achievable summer capacity for gas-fired capacity running on oil was 51.6 percent of all switchable natural gas-fired capacity. This ratio has gradually declined to 32.1 percent by the end of 2007.

Interconnection Costs

During 2007, 269 generators representing a total nameplate capacity of 14,061 MW were connected for the first time to the electric grid. The interconnection costs are presented by producer type (Table 2.12) and by distribution, subtransmission and transmission voltage class (Table 2.13). Total cost for individual generator interconnection varies based on its components. The components of the total cost may vary based on whether or not an interconnection infrastructure was already in place, and the type of equipment for which costs were incurred, along with other factors associated with the generator technology. Though the amount of capacity connected to the grid was about the same for both independent power producers (IPP) and electric utilities, the total cost for the IPP sector was significantly greater due in part to the interconnection of several large wind plants. Typically sited in relatively remote locations, wind plants usually require the construction of longer transmission line extensions to the plant sites than might be required for conventional power plants.

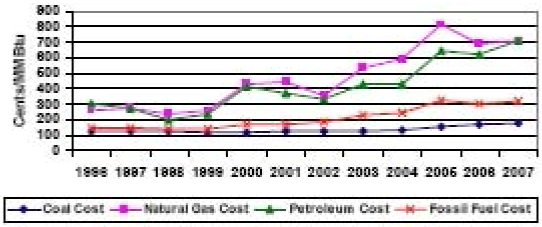
Fuel Costs

The 2007 average delivered cost for all fossil fuels used at electric power plants (coal, petroleum, and natural gas combined) for electricity generation was \$3.23 per million British thermal units (MMBtu) (Figure ES4) as compared to \$3.02 per MMBtu in 2006, an increase of 6.9 percent. Between 2003 and 2007, the average cost of all fossil fuels has increased 41.7 percent. The price of all fossil fuels increased in 2007. The cost of natural gas at electric power plants in 2007 increased 2.4 percent to \$7.11 per MMBtu. Since 2002, natural gas prices have increased 99.7 percent, with more than half of the total increase occurring between 2002 and 2003.

The cost of petroleum increased 15.1 percent, from $6.23 per MMBtu in 2006 to $7.17 MMBtu in 2007. This increase was caused by increased global demand for petroleum and tight supply. Petroleum-fired generation increased in spite of the significant increase in petroleum prices. This appears to be the result of petroleum capacity being used partially to offset the decline in conventional hydroelectric generation.

The 2007 delivered cost of coal increased 4.7 percent, from $1.69 per MMBtu in 2006 to $1.77 MMBtu in 2007. This marked the seventh straight year that coal prices have increased. Since 2000 the delivered cost of coal has increased 47.5 percent (Figure ES4).

Figure ES 4. Fuel Costs for Electricity Generation, 1996- 2007



Source: Energy Information Administration, Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report," Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants," “Annual Electric Generator Report;” Form EIA-923, "Power Plant Operations Report.”

Emissions

The estimated carbon dioxide, sulfur dioxide and nitrogen oxide emissions for electricity are based on the fossil fuels consumed by electric power plants for electric power generation, and fossil fuels consumed by combined heat and power plants for the generation of electric power and useful thermal output. The emissions factors used in the estimation methodology are described in the discussion of Air Emissions in the Technical Notes, and are summarized in Tables A1, A2, and A3.

Estimated carbon dioxide emissions by U.S. electric generators and combined heat and power facilities increased by 2.3 percent from 2006 to 2007 (from 2,460 million metric tons to 2,517 million metric tons). This reverses the decline in carbon dioxide emissions reported for 2006. Total net generation of electricity from fossil fuels increased to meet the increase in demand in 2007. Coal-fired generation increased 1.3 percent and coal consumed for electric generation and by combined heat and power facilities increased by 1.5 percent. Petroleum-fired generation increased 2.5 percent and the petroleum consumed for electric generation and useful thermal output increased 1.1 percent from 131 million barrels in 2006 to 132 million barrels in 2007. Consumption of natural gas for electricity generation and useful thermal output, which contributes the least amount of carbon dioxide per Btu consumed, rose by 7.5 percent in 2007 as natural gas generation increased by 10.1 percent.

Estimated emissions of nitrogen oxides and sulfur dioxide declined for the second year in a row. Nitrogen oxides emissions dropped by 3.9 percent (from 3.799 to 3.650 million metric tons). Sulfur dioxide emissions decreased by 5.1 percent (from 9.524 to 9.042 million metric tons). Emissions of both of these gases are capped by the Clean Air Act and other legislation.

Trade

Total wholesale purchases of electric power in the United States declined in 2007 for the fourth straight year to 5,411 million MWh, a 1.7 percent reduction. Almost half the volume of wholesale sales is provided by energy-only providers, or power marketing companies, a class of electric entities, authorized by FERC to transact at market based rates, that came into being during the late 1990s with the deregulation of the wholesale power markets. In 2007, wholesale sales by wholesale power marketers and retail energy service providers increased from 2,446 million MWh in 2006 to 2,477 MWh, which represented 45.2 percent of the wholesale market. This is the first increase in market share for these entities since 2002 when they accounted for 67.2 percent of all wholesale sales. Independent power producers and combined heat and power (CHP) plants accounted for 25.5 percent of wholesale sales in 2007 compared to 24.6 percent in 2006.

The Nation’s only international trade in electric power is with Canada and Mexico, and nearly all the trade is conducted with Canada. Most Mexican electric power trade is done with the State of California, while transactions with Canada are conducted through several large transmission corridors located in the Pacific Northwest, the Northern Plains, and New England. Much of the electricity provided from Canada is hydroelectric generation available for sale because of heavy seasonal river flows.

Total international net imports of electric power in 2007 increased 69.7 percent, from 18.4 million MWh in 2006 to 31.3 million

MWh. Overall, total U.S. imports increased 8.7 million MWh in 2007 from 42.7 million MWh in 2006 to 51.4 million MWh, while exports declined by 4.1 million MWh. Imports from Canada increased from 41.5 million MWh in 2006 to 50.1 million MWh in 2007, and U.S. exports decreased from 23.4 million MWh to 19.6 million MWh. Electricity trade with Mexico followed a similar pattern of net imports, increasing relative to 2006 as a result of a decline in exports and an increase in imports. Net imports more than doubled, from 0.3 million MWh in 2006 to 0.7 million MWh in 2007.

Revenue and Expense Statistics

In 2007, major investor-owned electric utility operating revenues (from sales to ultimate customers, sales for resale, and other electric income) were $283 billion, a 2.1 percent increase from 2006. Operating expenses in 2007 stayed in line with revenue growth, also increasing 2.0 percent, to $252 billion. Net income in 2007 was $30.7 billion, a slight increase over the $30.0 billion realized in 2006.

In 2007, major investor-owned electric utility purchased power costs, which accounted for roughly 30 percent of total utility operating expenses, fell 1.7 percent as compared to the 1.5 percent increase realized in 2006. Fuel costs increased 10.5 percent in 2007. Transmission expenses were $6.1 billion in 2007 as compared to $6.2 billion in 2006. This modest decrease stands in contrast to the average 21.2 percent annual increase between 2001 and 2006. Distribution expenses increased 5.8 percent, more than twice the average annual increase incurred between 2001 and 2006.

Electricity Prices and Sales

In 2007, the average retail price for all customers rose 0.2 cents to 9.1 cents per kWh. This amounted to a 2.6 percent increase over the 8.9 cents per kWh average retail price paid in 2006. Year-over-year, the average retail price for all customers served increased in 40 of the 50 States. The average price of electricity increased by 10 percent or more in 5 States. In another 11 States, the average price for all customers declined within a 0.2 percent to 6.1 percent range. The average price of electricity to all customers increased in all regions of the country, with the exception of the West South Central Census Division. Within the four States of the West South Central Census Division, average electric prices declined by 1.6 percent. In Arkansas the average retail rate for all customers declined by 0.4 percent. In Oklahoma the average price declined by 0.2 percent and in Texas it declined by 2.3 percent. In Louisiana, the average electricity price for all customers increased by 1.0 percent. The East North Central Census Division experienced the largest increase in average retail prices for all customers at 6.9 percent. The New England and East South Central Census Divisions had the next largest average retail price increases over 2006, at 4.0 percent and 3.4 percent, respectively. The lowest regional price increase was in the Pacific Contiguous Census Division, where the average price to all customers increased 0.8 percent over 2006.

Residential prices increased to 10.7 cents per kWh, or 2.4 percent, between 2006 and 2007. The average residential price increased by 10 percent or more in 6 States and the District of Columbia. These jurisdictions implemented retail competition and all of the investor-owned utilities operating within them participate in organized, competitive wholesale markets operated by independent system operators. The average residential price in Maryland increased 22.4 percent, from 9.7 cents per kWh in 2006 to 11.9 cents per kWh in 2007. This was the largest average increase in the Nation. It was caused by the transition to market based rates for the wholesale electricity portion of retail electric service. In order to mitigate the impact of higher retail prices, the Maryland Public Service Commission approved a plan for the largest investor-owned utility in the state that gave customers two payment options. The first option provided for retail prices based on the full market price of wholesale electricity prices, effective June 1, 2007. This option resulted in approximately a 50 percent increase in the average electric bill. The second option provided that the cost of wholesale electricity would be phased in over the 6 month period ending January 1, 2008. Deferred costs would be recovered by December 31, 2009.[8]

After Maryland, Illinois had the next largest increase in residential prices at 20.1 percent, followed by Maine (19.7 percent), Connecticut (13.4 percent), the District of Columbia (12.9 percent), Delaware (11.1 percent) and New Jersey (10.1 percent). On a regional basis, the highest average residential price increase was observed in the East North Central Division. This was primarily driven by Illinois, where the average residential price increase was nearly 4 times the average of the region overall. Like Maryland, the price increase in Illinois was the result of the termination of rate caps that had been put in place in 1997 as part of the transition to retail competition. Average residential prices in the New England and Mid-Atlantic Census Divisions increased 4.5 percent. Average residential prices fell by 2.9 percent in the West South Central Census Division, the only region to see a year-over-year decline in average residential prices. Texas out-paced the region with a 4.0 percent decline from 12.9 cents per kWh in 2006 to 12.3 cents per kWh in 2007.

A number of these States have taken legislative action in response to significant rate increases caused by a combination of rising fuel prices and the termination of rate caps imposed during the transition to retail competition. In Illinois average residential prices increased by 20.1 percent. The large average price increases for all customer groups in Illinois reflects the January 2, 2007 termination of the 10-year rate freeze that was imposed on the State’s investor-owned utilities as part of its 1997 electric industry restructuring legislation. The termination of the rate freeze caused large rate increases primarily for residential and certain non-residential customers that did not select alternative energy suppliers and remained customers of the State's largest investor-owned utilities under standard offer service rate schedules. On August 28, 2007, Illinois Senate Bill 1592 was signed into law, which provided approximately $1 billion in refunds, eliminated the auction process under which the Illinois investor-owned utilities purchased wholesale power to supply standard offer service, and created the Illinois Power Agency as the entity responsible for energy procurement. [9]

Average commercial prices increased from 9.5 to 9.7 cents per kWh, a 2.0 percent increase over 2006. The largest regional price increase was in the East North Central Census Division at 4.2 percent. Average commercial prices in Illinois increased 7.8 percent, from 7.9 cents per kWh to 8.6 cents per kWh. Wisconsin had the second highest rate increase in the region at 4.0 percent. The average commercial rate in the West South Central Census Division was unchanged at 9.3 cents per kWh. The average commercial price declined by slightly less than 1 percent in Arkansas and Oklahoma, while increasing by 0.2 percent in Texas and 1.2 percent in Louisiana. In the Pacific Contiguous Census Division the average commercial price declined from 11.2 cents per kWh in 2006 to 11.0 cents per kWh in 2007. It was the only region in which average commercial rates declined. Oregon was the only the State within the region where rates increased, rising from 6.8 cents per kWh to 7.2 cents per kWh.

Average industrial prices increased 4 percent from 6.2 cents per kWh in 2006 to 6.4 cents per kWh in 2007.

Total retail sales of electricity in 2007 were 3,764 million MWh. Annual growth in electricity sales in 2007 was 2.6 percent, exceeding the 1.8 percent year average annual growth rate since 1996. Sales to the residential sector increased by 3.0 percent from 2006 to 2007. Sales to the commercial sector increased by 2.8 percent, and industrial sales increased 1.6 percent. Since 1997, annual industrial sales declined in three years. Otherwise, with the exception of 2003 when industrial sales increased 2.2 percent, they have increased annually by less than one percent. Thus, while the increase in industrial sales in 2007 showed significant improvement over prior years, the faster growth of residential and commercial sales in 2007 provides for the continuation of the gradual shift of total load away from the industrial sector. The industrial sector accounted for 33.3 percent of total retail sales in 1996. By 2007 it has declined to 27.3 percent. Between 1996 and 2007, the commercial sector share of retail sales increased from 28.6 percent to 35.5 percent. Over the same period, the residential sector has grown from 34.9 percent of total retail sales to 37.0 percent.

In the last few years, some States have encouraged utilities to adopt customer service programs which respond to growing concerns about the environment, electricity reliability, and the rising cost of providing electricity. Green pricing programs allow consumers to purchase electricity generated from wind and other renewable sources and pay for renewable energy development. In 2007, 835,651 retail consumers were reported to be purchasing electricity under green pricing programs. Residential consumers accounted for 773,391 or 92.5 percent of the total number of green pricing consumers. All of the States, with the exception of Louisiana, reported providing electric service under green pricing programs in 2007. Retail consumers in Texas accounted for 17.0 percent of all green pricing consumers nationwide. Oregon was ranked second with 12.0 percent of all green pricing consumers Nationwide. The top 5 States were rounded out by California (7.0 percent) and Colorado (6.9 percent) and Maryland (6.7 percent). Together, retail consumers in these 5 States accounted for 49.6 of consumers purchasing green power and 56.0 percent of green power sales volumes Nationwide.

Net metering programs allow consumers with onsite generators to send excess generation to the grid and to receive credit for that energy on their bill. The number of customers in these programs has been steadily increasing. In 2002 there were 4,472 customers in net metering programs; in 2007 there were nearly 48,820 customers participating in net metering programs. These customers were dispersed across 47 States and the District of Columbia. California leads the Nation in net metering, with 34,910 customers reported as participating. These customers accounted for 71.5 percent of all customers participating in such programs.

Demand-Side Management

In 2007, electricity providers reported total peak-load reductions of 30,276 MW resulting from demand-side management (DSM) programs, an 11.1 percent increase from the amount reported in 2006. Reported DSM costs increased to $2.5 billion, up 23.2 percent from the $2.1 billion reported in 2006. DSM costs can vary significantly from year to year because of business cycle fluctuations and regulatory changes. Since costs are reported as they occur, while program effects may appear in future years, DSM costs and effects may not always show a direct relationship. Since 2003, nominal DSM expenditures have increased at 18.1 percent average annual growth rate. During the same period, actual peak load reductions have grown at a 7.2 percent average annual rate from, 22,904 MW to 30,276 MW. The divergence between the growth rates of load reduction and expenditures is driven in large measure by 2007 expenditures, which are in response to higher overall energy prices. The full effect of these expenditures may appear in additional load reductions in the coming years. The combined DSM energy savings programs (i.e., load management and energy efficiency) increased to 69.1 million MWh in 2007 from 63.8 MWh.

[1] See http://bea.doc.gov/national/index.htm#gdp.

[2] See http://www.federalreserve.gov/releases/g17/Current/table11.txt, accessed November 24, 2008.

[3] *National Climatic Data Center, Climate of 2007 Annual Review, U.S. Drought, January 15, 2008, http://www.ncdc.noaa.gov/oa/climate/research/2007/ann/us-summary.html*

[4] *North American Electric Reliability Corporation, 2007/2008 Winter Reliability Assessment. November 2007., p.10*

[5] *North American Electric Reliability Corporation, 2007 Long-term Reliability Assessment 2007-2016, October 2007, p. 89*

[6] *Dispersed and distribute generators are commercial and industrial generators. Dispersed generators are not connected to the grid. Distributed generators are connected to the grid. Both types of generators may be installed at or near a customer's site, or at other locations, and both types of generators may be owned by either the customers of the distribution utility or by the utility. This data is collected at the distribution utility level on the Form EIA-861.*

[7] *The data required to average capacity factors for combined cycle and simple cycle natural gas-fired generation was obtained from plant-specific capacity and energy data from the Form EIA-860, Form EIA-906 and Form EIA-920.*

[8] *In the Matter of Baltimore Gas and Electric Company's Proposal to Implement a Rate Stabilization Plan Pursuant to Section 7-548 of the Public Utility companies Article and the Commission's Inquiry into Factors Impacting Wholesale Electricity Prices, Maryland Public Service Commission, Order No. 81423. Case No. 9099, May 23, 2007.*

[9] *Illinois General Assembly, Public Act 095-0481, effective August 28, 2007.*

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DOE/EIA-0383(2009)
March 2009

Annual Energy Outlook 2009

With Projections to 2030

For Further Information . . .

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The *Annual Energy Outlook 2009* is available on the EIA web site at www.eia.doe.gov/oiaf/aeo/. Assumptions underlying the projections, tables of regional results, and other detailed results will also be available, at web sites www.eia.doe.gov/oiaf/assumption/ and /supplement/. Model documentation reports for the National Energy Modeling System are available at web site http://tonto.eia.doe.gov/reports/reports_kindD.asp?type=model documentation and will be updated for the *Annual Energy Outlook 2009* during 2009.

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DOE/EIA-0383(2009)

Annual Energy Outlook 2009

With Projections to 2030

March 2009

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This publication is on the WEB at:
www.eia.doe.gov/oiaf/aeo/

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Preface

The *Annual Energy Outlook 2009* (*AEO2009*), prepared by the Energy Information Administration (EIA), presents long-term projections of energy supply, demand, and prices through 2030, based on results from EIA's National Energy Modeling System (NEMS). EIA published an "early release" version of the *AEO2009* reference case in December 2008.

The report begins with an "Executive Summary" that highlights key aspects of the projections. It is followed by a "Legislation and Regulations" section that discusses evolving legislation and regulatory issues, including a summary of recently enacted legislation, such as the Energy Improvement and Extension Act of 2008 (EIEA2008). The next section, "Issues in Focus," contains discussions of selected topics, including: the impacts of limitations on access to oil and natural gas resources on the Federal Outer Continental Shelf (OCS); the implications of uncertainty about capital costs for new electricity generating plants; and the result of extending the Federal renewable production tax credit (PTC). It also discusses the relationship between natural gas and oil prices and the basis of the world oil price and production trends in *AEO2009*.

The "Market Trends" section summarizes the projections for energy markets. The analysis in *AEO2009* focuses primarily on a reference case, low and high economic growth cases, and low and high oil price cases. Results from a number of other alternative cases also are presented, illustrating uncertainties associated with the reference case projections for energy demand, supply, and prices. Complete tables for the five primary cases are provided in Appendixes A through C. Major results from many of the alternative cases are provided in Appendix D.

AEO2009 projections are based on Federal, State, and local laws and regulations in effect as of November 2008. The potential impacts of pending or proposed legislation, regulations, and standards (and sections of existing legislation that require implementing regulations or funds that have not been appropriated) are not reflected in the projections.

AEO2009 is published in accordance with Section 205c of the Department of Energy (DOE) Organization Act of 1977 (Public Law 95-91), which requires the EIA Administrator to prepare annual reports on trends and projections for energy use and supply.

Projections in *AEO2009* are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The projections are business-as-usual trend estimates, given known technology and technological and demographic trends. *AEO2009* assumes that current laws and regulations are maintained throughout the projections. Thus, the projections provide a policy-neutral baseline that can be used to analyze policy initiatives.

Because energy markets are complex, models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty. Many key uncertainties in the *AEO2009* projections are addressed through alternative cases.

EIA has endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not a substitute for, a complete and focused analysis of public policy initiatives.

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Executive Summary

The past year has been a tumultuous one for world energy markets, with oil prices soaring through the first half of 2008 and diving in its second half. The downturn in the world economy has had a significant impact on energy demand, and the near-term future of energy markets is tied to the downturn's uncertain depth and persistence. The recovery of the world's financial markets is especially important for the energy supply outlook, because the capital-intensive nature of most large energy projects makes access to financing a critical necessity.

The projections in *AEO2009* look beyond current economic and financial woes and focus on factors that drive U.S. energy markets in the longer term. Key issues highlighted in the *AEO2009* include higher but uncertain world oil prices, growing concern about greenhouse gas (GHG) emissions and its impacts on energy investment decisions, the increasing use of renewable fuels, the increasing production of unconventional natural gas, the shift in the transportation fleet to more efficient vehicles, and improved efficiency in end-use appliances. Using a reference case and a broad range of sensitivity cases, *AEO2009* illustrates these key energy market trends and explores important areas of uncertainty in the U.S. energy economy. The *AEO2009* cases, which were developed before enactment of the American Recovery and Reinvestment Act of 2009 (ARRA2009) in February 2009, reflect laws and policies in effect as of November 2008.

AEO2009 also includes in-depth discussions on topics of special interest that may affect the energy market outlook, including changes in Federal and State laws and regulations and recent developments in technologies for energy production and consumption. Some of the highlights for selected topics are mentioned in this Executive Summary, but readers interested in other issues or a fuller discussion should look at the Legislation and Regulations and Issues in Focus sections.

Developments in technologies for energy production and consumption that are discussed and analyzed in this report include the impacts of growing concerns about GHG emissions on investment decisions and how those impacts are handled in the *AEO2009* projections; the impacts of extending the PTC for renewable fuels by 10 years; the impacts of uncertainty about construction costs for electric power plants; the relationship between natural gas prices and oil prices; the economics of bringing natural gas from Alaska's North Slope to U.S. markets; expectations for oil shale production; the economics of plug-in electric hybrids; and trends in world oil prices and production.

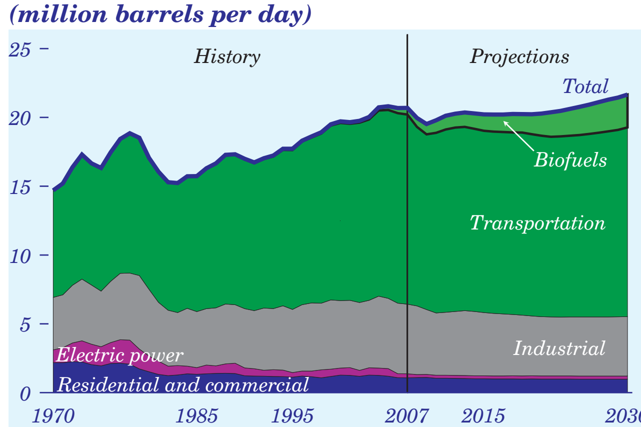
World Oil Prices, Oil Use, and Import Dependence

Despite the recent economic downturn, growing demand for energy—particularly in China, India, and other developing countries—and efforts by many countries to limit access to oil resources in their territories that are relatively easy to develop are expected to lead to rising real oil prices over the long term. In the *AEO2009* reference case, world oil prices rise to \$130 per barrel (real 2007 dollars) in 2030; however, there is significant uncertainty in the projection, and 2030 oil prices range from \$50 to \$200 per barrel in alternative oil price cases. The low price case represents an environment in which many of the major oil-producing countries expand output more rapidly than in the reference case, increasing their share of world production beyond current levels. In contrast, the high price case represents an environment where the opposite would occur: major oil-producing countries choose to maintain tight control over access to their resources and develop them more slowly.

Total U.S. demand for liquid fuels grows by only 1 million barrels per day between 2007 and 2030 in the reference case, and there is no growth in oil consumption. Oil use is curbed in the projection by the combined effects of a rebounding oil price, more stringent corporate average fuel economy (CAFE) standards, and requirements for the increased use of renewable fuels (Figure 1).

Growth in the use of biofuels meets the small increase in demand for liquids in the projection. Further, with increased use of biofuels that are produced domestically and with rising domestic oil production spurred

Figure 1. Total liquid fuels demand by sector (million barrels per day)



by higher prices in the *AEO2009* reference case, the net import share of total liquid fuels supplied, including biofuels, declines from 58 percent in 2007 to less than 40 percent in 2025 before increasing to 41 percent in 2030. The net import share of total liquid fuels supplied in 2030 varies from 30 percent to 57 percent in the alternative oil price cases, with the lowest share in the high price case, where higher oil prices dampen liquids demand and at the same time stimulate more production of domestic petroleum and biofuels.

Growing Concerns about Greenhouse Gas Emissions

Although no comprehensive Federal policy has been enacted, growing concerns about GHG emissions appear to be affecting investment decisions in energy markets, particularly in the electricity sector. In the United States, potential regulatory policies to address climate change are in various stages of development at the State, regional, and Federal levels. U.S. electric power companies are operating in an especially challenging environment. In addition to ongoing uncertainty with respect to future demand growth and the costs of fuel, labor, and new plant construction, it appears that capacity planning decisions for new generating plants already are being affected by the potential impacts of policy changes that could be made to limit or reduce GHG emissions.

This concern is recognized in the reference case and leads to limited additions of new coal-fired capacity—much less new coal capacity than projected in recent editions of the *Annual Energy Outlook* (*AEO*). Instead of relying heavily on the construction of new coal-fired plants, the power industry constructs more new natural-gas-fired plants, which account for the largest share of new power plant additions, followed by smaller amounts of renewable, coal, and nuclear capacity. From 2007 to 2030, new natural-gas-fired plants account for 53 percent of new plant additions in the reference case, and coal plants account for only 18 percent.

Two alternative cases in *AEO2009* illustrate how uncertainty about the evolution of potential GHG policies could affect investment behavior in the electric power sector. In the no GHG concern case, it is assumed that concern about GHG emissions will not affect investment decisions in the electric power sector. In contrast, in the LW110 case, the GHG emissions reduction policy proposed by Senators Lieberman and Warner (S. 2191) in the 110th Congress is incorporated to illustrate a future in which an explicit Federal policy is enacted to limit U.S. GHG emissions. The results in this case should be viewed as illustrative, because the projected impact of any policy to reduce GHG emissions will depend on its detailed specifications, which are likely to differ from those used in the LW110 case.

Projections in the two alternative cases illustrate the potential importance of GHG policy changes to the electric power industry and why uncertainty about such changes weighs heavily on planning and investment decisions. Relative to the reference case, new coal plants play a much larger role in meeting the growing demand for electricity in the no GHG concern case, and the role of natural gas and nuclear plants is diminished. In this case, new coal plants account for 38 percent of generating capacity additions between 2007 and 2030. In contrast, in the LW110 case there is a strong shift toward nuclear and renewable generation, as well as fossil technologies with carbon capture and storage (CCS) equipment.

There is also a wide divergence in electricity prices in the two alternative GHG cases. In the no GHG concern case, electricity prices are 3 percent lower in 2030 than in the reference case; in the LW110 case, they are 22 percent higher in 2030 than in the reference case.

Increasing Use of Renewable Fuels

The use of renewable fuels grows strongly in *AEO2009*, particularly in the liquid fuels and electricity markets. Overall consumption of marketed renewable fuels—including wood, municipal waste, and biomass in the end-use sectors; hydroelectricity, geothermal, municipal waste, biomass, solar, and wind for electric power generation; ethanol for gasoline blending; and biomass-based diesel—grows by 3.3 percent per year in the reference case, much faster than the 0.5-percent annual growth in total energy use. The rapid growth of renewable generation reflects the impacts of the renewable fuel standard in the Energy Independence and Security Act of 2007 (EISA2007) and strong growth in the use of renewables for electricity generation spurred by renewable portfolio standard (RPS) programs at the State level.

EISA2007 requires that 36 billion gallons of qualifying credits from biofuels be produced by 2022 (a credit is roughly one gallon, but some biofuels may receive more than one credit per gallon); and although the reference case does not show that credit level being achieved by the 2022 target date, it is exceeded by 2030. The volume of biofuels consumed is sensitive to the price of the petroleum-based products against which they compete. As a result, total liquid biofuel consumption varies significantly between the reference case projection and the low and high oil price cases. In the low oil price case, total liquid biofuel consumption reaches 27 billion gallons in 2030. In the high oil price case, where the price of oil approaches $200 per barrel (real 2007 dollars) by 2030, it reaches 40 billion gallons.

As of November 2008, 28 States and the District of Columbia had enacted RPS requirements that a specified share of the electricity sold in the State come from various renewable sources. As a result, the share of electricity sales coming from nonhydroelectric renewables grows from 3 percent in 2007 to 9 percent in 2030, and 33 percent of the increase in total generation comes from nonhydroelectric renewable sources. The share of sales accounted for by nonhydroelectric renewables could grow further if more States adopted or strengthened existing RPS requirements. Moreover, the enactment of polices to reduce GHG emissions could stimulate additional growth. In the LW110 case, the share of electricity sales accounted for by nonhydroelectric renewable generation grows to 18 percent in 2030.

Growing Production from Unconventional Natural Gas Resources

Relative to recent *AEO*s, the *AEO2009* reference case raises EIA's projection for U.S. production and consumption of natural gas, reflecting a larger resource base and higher demand for natural gas for electricity generation. Among the various sources of natural gas, the most rapid growth is in domestic production from unconventional resources, while the role played by pipeline imports and imports of liquefied natural gas (LNG) declines over the long term (Figure 2).

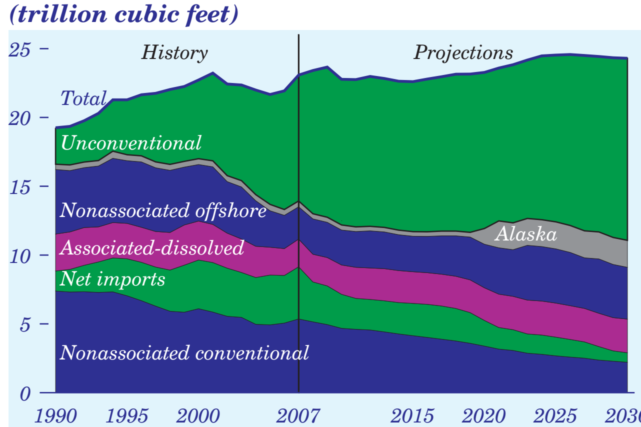
The larger natural gas resource in the reference case results primarily from a larger estimate for natural gas shales, with some additional impact from the 2008 lifting of the Executive and Congressional moratoria on leasing and development of crude oil and natural gas resources in the OCS. From 2007 to 2030, domestic production of natural gas increases by 4.3 trillion feet (22 percent), while net imports fall by 3.1 trillion cubic feet (83 percent). Although average real U.S. wellhead prices for natural gas increase from $6.39 per thousand cubic feet in 2007 to $8.40 per thousand cubic feet in 2030, stimulating production from domestic resources, the prices are not high enough to attract large imports of LNG, in a setting where world LNG prices respond to the rise of oil prices in the *AEO2009* reference case. One result of the growing production of natural gas from unconventional onshore sources, together with increases from the OCS and Alaska, is that the net import share of U.S. total natural gas use also declines, from 16 percent in 2007 to less than 3 percent in 2030.

In addition to concerns and/or policies regarding GHG emissions, the overall level of natural gas consumption that supply must meet is sensitive to many other factors, including the pace of economic growth. In the *AEO2009* alternative economic growth cases, consumption of natural gas in 2030 varies from 22.7 trillion cubic feet to 26.0 trillion cubic feet, roughly 7 percent below and above the reference case level.

Shifting Mix of Unconventional Technologies in Cars and Light Trucks

Higher fuel prices, coupled with significant increases in fuel economy standards for light-duty vehicles (LDVs) and investments in alternative fuels infrastructure, have a dramatic impact on development and sales of alternative-fuel and advanced-technology LDVs. The *AEO2009* reference case includes a sharp increase in sales of unconventional vehicle technologies, such as flex-fuel, hybrid, and diesel vehicles. Hybrid vehicle sales of all varieties increase from 2 percent of new LDV sales in 2007 to 40 percent in 2030. Sales of plug-in hybrid electric vehicles (PHEVs) grow to almost 140,000 vehicles annually by 2015, supported by tax credits enacted in 2008, and they account for 2 percent of all new LDV sales in

Figure 2. Total natural gas supply by source (trillion cubic feet)



2030. Diesel vehicles account for 10 percent of new LDV sales in 2030 in the reference case, and flex-fuel vehicles (FFVs) account for 13 percent.

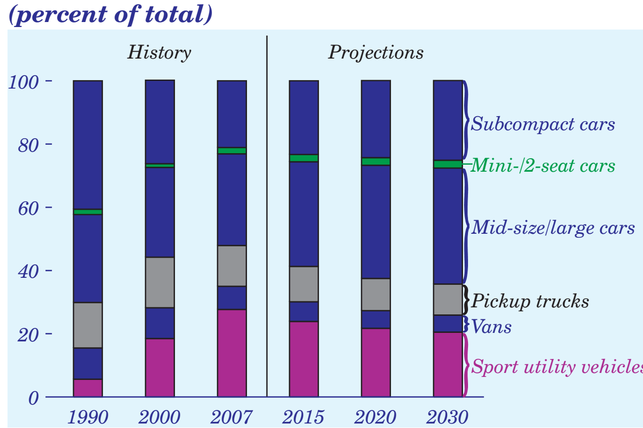
In addition to the shift to unconventional vehicle technologies, the *AEO2009* reference case shows a shift in the LDV sales mix between cars and light trucks (Figure 3). Driven by rising fuel prices and the cost of CAFE compliance, the sales share of new light trucks declines. In 2007, light-duty truck sales accounted for approximately 50 percent of new LDV sales. In 2030, their share is down to 36 percent, mostly as a result of a shift in LDV sales from sport utility vehicles to mid-size and large cars.

Slower Growth in Overall Energy Use and Greenhouse Gas Emissions

The combination of recently enacted energy efficiency policies and rising energy prices in the *AEO-2009* reference case slows the growth in U.S. consumption of primary energy relative to history: from 101.9 quadrillion British thermal units (Btu) in 2007, energy consumption grows to 113.6 quadrillion Btu in 2030, a rate of increase of 0.5 percent per year. Further, when slower demand growth is combined with increased use of renewables and a reduction in additions of new coal-fired conventional power plants, growth in energy-related GHG emissions also is slowed relative to historical experience. Energy-related emissions of carbon dioxide (CO_2) grow at a rate of 0.3 percent per year from 2007 to 2030 in the *AEO2009* reference case, to 6,414 million metric tons in 2030, compared with the *Annual Energy Outlook 2008* (*AEO2008*) reference case projection of 6,851 million metric tons in 2030.

One key factor that drives growth in both total energy consumption and GHG emissions is the rate of overall economic growth. In the *AEO2009* reference case, the U.S. economy grows by an average of 2.5 percent per year. In comparison, in alternative low and high economic growth cases, the average annual growth rates from 2007 to 2030 are 1.8 percent and 3.0 percent. In the two cases, total primary energy consumption in 2030 ranges from 104 quadrillion Btu (8.2 percent below the reference case) to 123 quadrillion Btu (8.6 percent above the reference case). Energy-related CO_2 emissions in 2030 range from 5,898 million metric tons (8.1 percent below the reference case) in the low economic growth case to 6,886 million metric tons (7.3 percent above the reference case) in the high economic growth case.

Figure 3. New light-duty vehicle sales shares by type (percent of total)



Legislation and Regulations

Legislation and Regulations

Introduction

Because baseline projections developed by EIA are required to be policy-neutral, the projections in *AEO2009* are based on Federal and State laws and regulations as of November 2008 [*1*]. The potential impacts of pending or proposed legislation, regulations, and standards—or of sections of legislation that have been enacted but that require implementing regulations or appropriation of funds that are not provided or specified in the legislation itself—are not reflected in the projections. Throughout 2008, however, at the request of the Administration and Congress, EIA has regularly examined the potential implications of proposed legislation in Service Reports (see box below).

Examples of Federal and State legislation that has been enacted over the past few years and is incorporated in *AEO2009* include:

- The tax provisions of EIEA2008, signed into law on October 3, 2008, as part of Public Law 110-343, the Emergency Economic Stabilization Act of 2008 (see details below)
- The biofuel provisions of the Food, Conservation, and Energy Act of 2008 (Public Law 110-234) [*2*], which reduce the existing ethanol excise tax credit in the first year after U.S. ethanol production and imports exceed 7.5 billion gallons and add an income tax credit for the production of cellulosic biofuels

EIA Service Reports Released Since January 2008

The table below summarizes the Service Reports completed since 2008. Those reports, and others that were completed before 2008, can be found on the EIA web site at www.eia.doe.gov/oiaf/service_rpts.htm.

Title	*Date of release*	*Requestor*	*Availability on EIA web site*	*Focus of analysis*
Light-Duty Diesel Vehicles: Efficiency and Emissions Attributes and Market Issues	*February 2009*	*Senator Jeff Sessions*	*www.eia.doe.gov/oiaf/servicerpt/lightduty/index.html*	*Analysis of the environmental and energy efficiency attributes of LDVs, including comparison of the characteristics of diesel-fueled vehicles with those of similar gasoline-fueled, E85-fueled, and hybrid vehicles, as well as a discussion of any technical, economic, regulatory, or other obstacles to increasing the use of diesel-fueled vehicles in the United States.*
State Energy Data Needs Assessment	*January 2009*	*Required by EISA2007*	*www.eia.doe.gov/oiaf/servicerpt/energydata/index.html*	*Response to EISA2007 Section 805(d), requiring EIA to assess State-level energy data needs and submit to Congress a plan to address those needs.*
The Impact of Increased Use of Hydrogen on Petroleum Consumption and Carbon Dioxide Emissions	*September 2008*	*Senator Byron Dorgan*	*www.eia.doe.gov/oiaf/servicerpt/hydro/index.html*	*Analysis of the impacts on U.S. energy import dependence and emission reductions resulting from the commercialization of advanced hydrogen and fuel cell technologies in the transportation and distributed generation markets.*
Analysis of Crude Oil Production in the Arctic National Wildlife Refuge	*May 2008*	*Senator Ted Stevens*	*www.eia.doe.gov/oiaf/servicerpt/anwr/index.html*	*Assessment of Federal oil and natural gas leasing in the coastal plain of the Arctic National Wildlife Refuge in Alaska.*
Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007	*April 2008*	*Senators Joseph Lieberman, John Warner, James Inhofe, George Voinovich, and John Barrasso*	*www.eia.doe.gov/oiaf/servicerpt/s2191/index.html*	*Analysis of impacts of the greenhouse gas cap-and-trade program established under Title I of S. 2191.*
Federal Financial Interventions and Subsidies in Energy Markets 2007	*April 2008*	*Senator Lamar Alexander*	*www.eia.doe.gov/oiaf/servicerpt/subsidy2/index.html*	*Update of 1999-2000 EIA work on Federal energy subsidies, including any additions or deletions of Federal subsidies based on Administration or Congressional action since 2000, and an estimate of the size of each current subsidy.*
Energy Market and Economic Impacts of S. 1766, the Low Carbon Economy Act of 2007	*January 2008*	*Senators Jeff Bingaman and Arlen Specter*	*www.eia.doe.gov/oiaf/servicerpt/lcea/index.html*	*Analysis of mandatory greenhouse gas allowance program under S. 1766 designed to maintain covered emissions at approximately 2006 levels in 2020, 1990 levels in 2030, and at least 60 percent below 1990 levels by 2050.*

- The provisions of EISA2007 (Public Law 110-140) including: a renewable fuel standard (RFS) requiring the use of 36 billion gallons of ethanol by 2022; an attribute-based minimum CAFE standard for cars and trucks of 35 miles per gallon (mpg) by 2020; a program of CAFE credit trading and transfer; various appliance efficiency standards; a lighting efficiency standard starting in 2012; and a number of other provisions related to industrial waste heat or natural gas efficiency, energy use in Federal buildings, weatherization assistance, and manufactured housing
- Those provisions of the Energy Policy Act of 2005 (EPACT2005), Public Law 109-58, that remain in effect and have not been superseded by EISA-2007, including: mandatory energy conservation standards; numerous tax credits for businesses and individuals; elimination of the oxygen content requirement for Federal reformulated gasoline (RFG); extended royalty relief for offshore oil and natural gas producers; authorization for DOE to issue loan guarantees for new or improved technology projects that avoid, reduce, or sequester GHGs; and a PTC for new nuclear facilities
- Public Law 108-324, the Military Construction Appropriations Act of 2005, which contains provisions to encourage construction of an Alaska natural gas pipeline, including Federal loan guarantees during construction
- State RPS programs, representing laws and regulations of 27 States and the District of Columbia that require renewable electricity generation.

Examples of recent Federal and State regulations as well as earlier provisions that have been affected by court decisions that are considered in *AEO2009* include the following:

- Decisions by the D.C. Circuit Court of the U.S. Court of Appeals on February 8, 2008, to vacate and remand the Clean Air Mercury Rule (CAMR) and on July 11, 2008, to vacate and remand the Clean Air Interstate Rule (CAIR) [*3*]
- Release by the California Air Resources Board (CARB) in October 2008 of updated regulations for RFG that went into effect on August 29, 2008, allowing a 10-percent ethanol blend, by volume, in gasoline.

More detailed information on recent Federal and State legislative and regulatory developments is provided below.

Energy Improvement and Extension Act of 2008: Summary of Provisions

The Emergency Economic Stabilization Act of 2008 (Public Law 110-343) [*4*], which was signed into law on October 3, 2008, incorporates EIEA2008 in Division B. Provisions in EIEA2008 that require funding appropriations to be implemented, whose impact is highly uncertain or that require further specification by Federal agencies or Congress, are not included in *AEO2009*. Moreover, *AEO2009* does not include any provision that addresses a level of detail beyond that modeled in NEMS. *AEO2009* addresses those provisions in EIEA2008 that establish specific tax credits and incentives, including the following:

- Extension of the residential and business tax credits for renewable energy as well as for the purchase and production of certain energy-efficient appliances, many of which were originally enacted in EPACT2005
- Removal of the cap on the tax credit for purchases of residential solar photovoltaic (PV) installations and an increase in the tax credit for residential ground-source heat pumps
- Addition of a business investment tax credit (ITC) for combined heat and power (CHP), small wind systems, and commercial ground-source heat pumps
- Provision of a tax credit for the purchase of new, qualified, plug-in electric drive motor vehicles
- Extension of the income and excise tax credits for biodiesel and renewable diesel to the end of 2009 and an increase in the amount of the tax credit for biodiesel and renewable diesel produced from recycled feedstock
- Provision of tax credits for the production of liquid petroleum gas (LPG), LNG, compressed natural gas (CNG), and aviation fuels from biomass
- Provision of an additional tax credit for the elimination of CO_2 that would otherwise be emitted into the atmosphere in enhanced oil recovery and non-enhanced oil recovery operations
- Extension and modification of key renewable energy tax provisions that were scheduled to expire at the end of 2008, including production tax credits (PTCs) for wind, geothermal, landfill gas, and certain biomass and hydroelectric facilities
- Expansion of the PTC-eligible technologies to include plants that use energy from offshore, tidal, or river currents (in-stream turbines), ocean waves, or ocean thermal gradients.

The following discussion provides a summary of the EIEA2008 provisions included in *AEO2009* and some of the provisions that could be included if more complete information were available about their funding and implementation. This discussion is not a complete summary of all the sections of EIEA2008.

End-Use Demand

Residential and Commercial Buildings

EIEA2008 reinstates and extends tax credits for renewable energy and for the purchase and production of certain energy-efficient appliances, many of which were originally enacted in EPACT2005. Some of the tax credits are extended to 2016. In addition, the $2,000 cap for residential PV purchases is removed, and the cap for ground-source heat pumps is raised from $300 to $2,000. The legislation also adds business ITCs for CHP, small wind systems, and commercial ground-source heat pumps.

Residential Tax Credits

EIEA2008 Titles I and III include various extensions, modifications, and additions to the tax code that have the potential to affect future energy demand in the residential sector. Sections 103 through 106 of Title I reinstate the tax credits that were implemented under EPACT2005 for efficient water heaters, boilers, furnaces, heat pumps, air conditioners, and building shell equipment, such as windows, doors, weather stripping, and insulation. The amount of the credit varies by appliance type and ranges from $150 to $300. The maximum credit for ground-source heat pumps, which was $300 under EPACT2005, is $2,000 under EIEA2008. For solar installations, which can receive a 30-percent tax credit under both EPACT-2005 and EIEA2008, the $2,000 cap has been removed. With the cost and unit size of residential PV assumed in *AEO2009*, the credit can now reach nearly $10,000 per unit. The tax credit for small wind generators is also extended through 2016 in EIEA2008; however, penetration of residential wind installations over the next decade is projected to be negligible.

Sections 302, 304, and 305 of EIEA2008 Title III also contain provisions that can directly or indirectly affect future residential energy demand. Section 302 adds a provision to allow a tax credit for the use of biomass fuel, which can include wood, wood pellets, and crops. In NEMS, the credit is represented as a reduction in the cost of wood stoves used as the primary space heating system. Section 304 extends the $2,000 tax credit for new homes that are 50 percent more efficient than specified in the International Energy Conservation Code through 2009. Section 305 extends the PTC for refrigerators, dishwashers, and clothes washing machines that are a certain percentage more efficient than the current Federal standard. The duration and value of the credit vary by appliance and the level of efficiency achieved. For *AE02009*, it is assumed that the full amount of the credit is realized by consumers in the form of reduced purchase costs.

Commercial Tax Credits

Sections 103, 104, and 105 of EIEA2008 Title I extend or expand tax credits to businesses for investment in energy efficiency and renewable energy properties. Section 103 extends the EPACT2005 business ITCs (30 percent for solar energy systems and fuel cells, 10 percent for microturbines) through 2016; expands the ITC to include a 10-percent credit for CHP systems through 2016; and increases the credit limit for fuel cells from $500 to $1,500 per half kilowatt of capacity. Section 104 provides a 30-percent business ITC through 2016 for wind turbines with an electrical capacity of 100 kilowatts or less, capped at $4,000. Section 105 adds a 10-percent business ITC for ground-source heat pumps through 2016. In the *AEO2009* reference case, relative to a case without the tax credits, these provisions result in a 3.2-percent increase in electrical capacity in the commercial sector by 2016.

Section 303 of EIEA2008 Title III extends the EPACT2005 tax deduction allowed for expenditures on energy-efficient commercial building property through 2013. This provision is not reflected in *AEO2009*, because NEMS does not include economic analysis at the building level.

Industrial Sector

Under EIEA2008 Title I, “Energy Production Incentives,” Section 103 provides an ITC for qualifying CHP systems placed in service before January 1, 2017. Systems with up to 15 megawatts of electrical capacity qualify for an ITC up to 10 percent of the installed cost. For systems between 15 and 50 megawatts, the percentage tax credit declines linearly with the capacity, from 10 percent to 3 percent. To qualify, systems must exceed 60-percent fuel efficiency, with a minimum of 20 percent each for useful thermal and electrical energy produced. The provision was modeled in *AEO2009* by adjusting the assumed capital cost of industrial CHP systems to reflect the applicable credit.

Section 108 extends an existing PTC, originally created under the American Jobs Creation Act of 2004 for new "refined coal" facilities producing steam coal, to those that produce metallurgical coal for the steel industry. The credit applies to coal processed with liquefied coal waste sludge and "steel industry coal" (defined as coal used for feedstock in coke manufacture). The production credit for steel industry coal is $2 per barrel of oil equivalent actually produced (equivalent to 34 cents per million Btu or $8.55 per short ton) over the first 10 years of operation for plants placed in service in 2008 and 2009. Because the *AEO2009* NEMS does not include the level of detail addressed by this tax credit, its incremental effect is not reflected in *AEO2009*. To the extent that the credit is passed on from coal suppliers as a reduction in the price of metallurgical coal, the provision would tend to reduce steel production costs and provide an incentive for domestic manufacture of coke.

Transportation Sector

EIEA2008 Title II, Section 205, provides a tax credit for the purchase of new, qualified plug-in electric drive motor vehicles. According to the legislation, a qualified plug-in electric drive motor vehicle must draw propulsion from a traction battery with at least 4 kilowatthours of capacity, use an off-board source of energy to recharge the battery, and, depending on the gross vehicle weight rating (GVWR), meet the U.S. Environmental Protection Agency (EPA) Tier II vehicle emission standards or equivalent California low-emission vehicle emission standards.

The tax credit for the purchase of a PHEV is $2,500 plus $417 per kilowatthour of traction battery capacity in excess of the minimum required 4 kilowatthours, up to a total of $7,500 for a PHEV with a GVWR of 10,000 pounds or less. The limit is raised to $10,000 for any new eligible PHEV with a GVWR between 10,000 and 14,000 pounds, $12,500 for a PHEV between 14,000 and 26,000 pounds GVWR, and $15,000 for any eligible PHEV with a GVWR greater than 26,000 pounds.

The legislation also includes a phaseout period for the tax credit, beginning two calendar quarters after the first quarter in which the cumulative number of qualified plug-in electric vehicles sold in total by all manufacturers reaches 250,000. The credit will be reduced by 50 percent in the first two calendar quarters of the phaseout period and by another 25 percent in the third and fourth calendar quarters. Thereafter, the credit will be eliminated. Regardless of calendar quarter or whether 250,000 vehicles are sold, the credit will be phased out after December 31, 2014. The tax credits for PHEVs are included in *AEO2009*.

Liquids and Natural Gas

EIEA2008 includes tax provisions that address petroleum liquids and natural gas. In Title II, "Transportation and Domestic Fuel Security Provisions, Credits for Biodiesel and Renewable Diesel," Section 202 extends income and excise tax credits for biodiesel and renewable diesel to the end of 2009. The legislation also raises the credit from 50 cents per gallon to $1 per gallon for biodiesel and renewable diesel from recycled feedstock. It also removes the term "thermal depolymerization" from the definition of renewable diesel and replaces it with "or other equivalent standard," allowing biomass-to-liquids (BTL) producers to obtain the $1 per gallon income tax credit. The legislation further specifies that the term "renewable diesel" shall include fuel derived from biomass that meets Defense Department specifications for military jet fuel or American Society for Testing and Materials specifications for aviation turbine fuel. These provisions are included in *AEO2009*.

Section 204 extends the excise tax credit for alternative fuels under Section 6426 of the Internal Revenue Code through 2009. Beginning on October 1, 2009, qualified fuel derived from coal through gasification and liquefaction processes must be produced at a facility that separates and sequesters at least 50 percent of its CO_2 emissions, increasing to 75 percent beginning in 2010. Section 204 also provides credits applicable to biomass gas versions of LPG, LNG, CNG, and aviation fuels. This provision is also included in *AEO2009*.

Coal

EIEA2008 Title I, Subtitle B, "Carbon Mitigation and Coal Provisions," modifies the tax credits available to coal consumers who sequester CO_2. In Section 111, an additional $1.25 billion is allocated to advanced coal-fired plants that separate and sequester a minimum of 65 percent of the plant's CO_2 emissions, bringing the aggregate ITC available for advanced coal projects to $2.55 billion. For this additional ITC, the allowable credit is equivalent to 30 percent of the project's qualified investment cost. Qualified investments include any expenses for property that is part of the project. For example, expenses for equipment for coal handling and gas separation would be qualifying investments if they were required for the project.

Section 112 provides an additional $250 million in ITCs for carbon sequestration equipment at qualified gasification projects, including plants producing transportation-grade liquid fuels. Eligible feedstocks for the projects include coal, petroleum residues, and biomass. To qualify for the ITC, a gasification facility must capture and sequester a minimum of 75 percent of its potential CO_2 emissions.

Section 115 of Subtitle B provides an additional tax credit for sequestration of CO_2 that would otherwise be emitted into the atmosphere from industrial sources. Tax credits of $10 per ton for CO_2 used in enhanced oil recovery and $20 per ton for other CO_2 sequestered are available. The Section 115 tax credit is limited to a total of 75 million metric tons of CO_2. In the *AEO2009* reference case, Sections 111, 112, and 115 are modeled together, resulting in 1 gigawatt of advanced coal-fired capacity with CCS by 2017.

Section 113 of Subtitle B extends the phaseout of payments by coal producers to the Black Lung Disability Trust Fund from 2013 to 2018. This provision also is modeled in the *AEO2009* reference case.

Other coal-related provisions of Subtitle B are not included in *AEO2009*, either because their effects on energy markets are minimal or nonexistent, or because they cannot be modeled directly in NEMS. They include: a provision that refunds payments to the Black Lung Disability Trust Fund for U.S. coal exports (Section 114); classification of income derived from industrial-source CO_2 by publicly traded partnerships as qualifying income (Section 116); a request for a National Academy of Sciences review of GHG provisions in the IRS Tax Code (Section 117); and a tax credit for alternative liquid fuels that is valid only through the end of 2009 (Section 204).

Renewable Energy

EIEA2008 also contains several provisions that extend and modify key tax provisions for renewable energy that were scheduled to expire at the end of 2008. Section 101 extends the PTC for wind, geothermal, landfill gas, and certain biomass and hydroelectric facilities. Wind facilities that enter service before January 1, 2010, are eligible for a tax credit of 2 cents per kilowatthour, adjusted for inflation, on all generation sold for the first 10 years of plant operation. Other eligible plants will receive the tax credit if they are on line by December 31, 2010 (but biomass plants that do not use "closed-loop" fuels [*5*] will receive a credit of 1 cent per kilowatthour).

Section 102 expands the suite of PTC-eligible technologies to include plants that use energy from offshore, tidal, or river currents (in-stream turbines), ocean waves, or ocean thermal gradients. Projects must have at least 150 kilowatts of capacity and must be on line by December 31, 2011. The PTC extension is included in *AEO2009* for all eligible technologies, with the exception of marine technologies, which are not represented in NEMS.

Section 103 extends the 30-percent ITC for business-owned solar facilities to plants entering service through December 31, 2016. The tax credit is valued at 30 percent of the initial investment cost for solar thermal and PV generating facilities that are owned by tax-paying businesses (residential owners can take advantage of tax credits discussed below; other forms of government assistance may be available to tax-exempt owners). Starting in 2017, eligible facilities will receive only a 10-percent ITC, which is not scheduled to expire. The extension through 2016 and the permanent 10-percent ITC are represented in *AEO2009*.

Section 107 authorizes continuation of the Clean and Renewable Energy Bonds (CREB) program at a level of $800 million. CREBs are issued by tax-exempt project owners (municipals and cooperatives) to raise capital for the construction of renewable energy plants. Interest on the bonds is paid by the Federal Government in the form of tax credits to the bond holders, thus providing the bond issuer with interest-free financing for qualified projects. Because NEMS assumes that all new renewable generation capacity will come from independent power producers, this provision, which targets public utilities, is not included in *AEO2009*.

Federal Fuels Taxes and Tax Credits

This section provides a review and update of the handling of Federal fuels taxes and tax credits, focusing primarily on areas for which regulations have changed or the handling of taxes or credits has been updated in *AEO2009*.

Excise Taxes on Highway Fuel

The handling of Federal highway fuel taxes remains unchanged from *AEO2008*. Consistent with current law, gasoline is assumed to be taxed at 18.4 cents per gallon, diesel fuel at 24.4 cents per gallon, and jet fuel at 4.3 cents per gallon. State fuel taxes, calculated as a volume-weighted average for diesel, gasoline, and jet fuels sold, were updated as of July 2008 [*6*]. Unlike Federal highway taxes, which remain at today's nominal levels throughout the *AEO2009* projection, State fuel taxes are assumed to remain fixed in real terms.

Biofuels Tax Credits

The only change in the handling of Federal fuels taxes and credits has been in those that pertain to biofuels. Section 15331 of the Food, Conservation, and Energy Act of 2008 reduces the existing ethanol excise tax credit of $0.51 per gallon to $0.45 per gallon in the first year after the year in which U.S. ethanol production and imports exceed 7.5 billion gallons. In the *AEO2009* projections, U.S. ethanol production and imports exceed 7.5 billion gallons in 2008, and the tax credit is reduced in 2009. The excise tax credit for ethanol is scheduled to expire at the end of 2010. In addition, Section 15321 of the Act adds an income tax credit for the production of cellulosic biofuels. The cellulosic biofuels represented in NEMS are cellulosic ethanol, BTL diesel, and BTL naphtha. The tax credit is $1.01 per gallon, but for cellulosic ethanol it is reduced by the amount of the excise tax credit available for ethanol blends (assumed to be $0.45 per gallon). The credit will be applied to fuel produced after December 31, 2008, and before January 1, 2013.

In EIEA2008, the excise tax credit of $1.00 per gallon for biodiesel, which previously was set to expire at the end of 2008, was extended through December 31, 2009. In addition, the excise tax credit of $0.50 per gallon for biodiesel made from recycled vegetable oils or animal fat is increased to $1.00 per gallon. A representation of renewable diesel—a diesel-like hydrocarbon produced by reaction of vegetable oil or animal fat with hydrogen, also known as “non-ester renewable diesel”—has been added to NEMS for *AEO2009*.

Ethanol Import Tariff

Currently, two duties are imposed on imported ethanol. The first is an *ad valorem* tariff of 2.5 percent. The second, which is a tariff of $0.54 per gallon after the application of the *ad valorem* tariff, allows for duty-free imports from designated Central American and Caribbean countries up to a limit of 7 percent of domestic production in the preceding year. The $0.54 per gallon tariff, previously set to expire on January 1, 2009, is extended to January 1, 2011, in Section 15333 of the Food, Conservation, and Energy Act of 2008. In *AEO2009*, the second tariff is assumed to expire on January 1, 2011.

New NHTSA CAFE Standards

EISA2007 requires the National Highway Traffic Safety Administration (NHTSA) to raise the CAFE standards for passenger cars and light trucks to ensure that the average tested fuel economy of the combined fleet of all new passenger cars and light trucks sold in the United States in model year (MY) 2020 equals or exceeds 35 mpg, 34 percent above the current fleet average of 26.4 mpg [*7*]. Pursuant to this legislation, NHTSA recently proposed revised CAFE standards that substantially increase the minimum fuel economy requirements for passenger cars and light trucks for MY 2011 through MY 2015 [*8*].

The new CAFE proposal builds on NHTSA’s 2006 decision to use an attribute-based methodology to determine a vehicle’s minimum fuel economy standard based on vehicle footprint [*9*]. The attribute-based CAFE standard uses a mathematical function that provides a unique fuel economy target for each vehicle footprint and is the same across manufacturers. Fuel economy targets are revised upward in subsequent model years to ensure improvement over time (Figures 4 and 5). Separate continuous mathematical functions are established for passenger cars and light trucks, reflecting their different design capabilities, and their combined fuel economy levels are required to reach 35 mpg by 2020.

Individual manufacturers will be required to comply with unique fuel economy levels for their car and light truck fleets, based on the distribution of their vehicle production by footprint in each model year. Individual manufacturers face different required CAFE levels only to the extent that their production distributions differ. NHTSA has estimated the impact of the new CAFE standard on the fuel economy of new LDVs and has projected that the proposed standards represent a 4.5-percent average annual increase in fuel economy between MY 2010 and MY 2015 (Table 1) [*10*]. Because the exact sales mix of different vehicle classes for a given manufacturer cannot be known until after the model year, NHTSA projects industry-wide average fuel economies for passenger cars and light trucks based on the manufacturers’ production plans.

From a fuel economy average of 31.6 mpg in MY 2015, the average annual increase from MY 2015 to MY 2020 would need to be only 2 percent to reach the EISA2007 mandate of 35 mpg by 2020. Thus, NHTSA’s latest proposal is heavily front-loaded, in that it requires greater gains in the first 5-year period than in the second.

Because *AEO2009* uses NHTSA’s proposed CAFE standards to represent the implementation path for the fuel economy standard required by EISA2007, the average fuel economy for LDVs in the early years of the projection is higher than projected in *AEO2008* (Figure 6). In the *AEO2009* reference case, the combined fuel economy of new LDVs from MY 2011 through MY 2015 slightly exceeds NHTSA's estimated values, because *AEO2009* allows shifting of sales between cars and light trucks and among various size classes, whereas NHTSA's estimates are based on manufacturers' production plans.

NHTSA's proposal also seeks to provide added flexibility for manufacturers to meet the new CAFE standards by: (1) allowing trading of credits between manufacturers who exceed their standards and those who do not; (2) allowing credit transfers between different vehicle classes for a single manufacturer; (3) increasing from 3 to 5 the number of years during which a manufacturer can "carry forward" credits earned from exceeding the CAFE standards in earlier model years, while leaving in place the 3-year limit for manufacturers to "carry back" credits earned in later years to meet shortfalls from previous model years; and (4) extending through 2014 the ability of manufacturers to earn a maximum 1.2 mpg of CAFE credit by producing alternative-fuel vehicles, then phasing out the "carry-back" credits between 2015 and 2019.

NHTSA's flexibility provisions do not, however, allow manufacturers to miss their annual targets grossly and then make them up by using any or all of the four provisions listed above. NHTSA retains a required minimum (92 percent of the applicable CAFE standard). Before any credit can be applied by a manufacturer, its fleet of LDVs for the model year must meet an average fuel economy standard—either 27.5 mpg or 92 percent of the CAFE for the industry-wide combined fleet of domestic and non-domestic passenger cars for that model year, whichever is higher. It is important to note that NHTSA's proposed CAFE standards are subject to change in future rulemakings.

Figure 4. Proposed CAFE standards for passenger cars by vehicle footprint, model years 2011-2015 (miles per gallon)

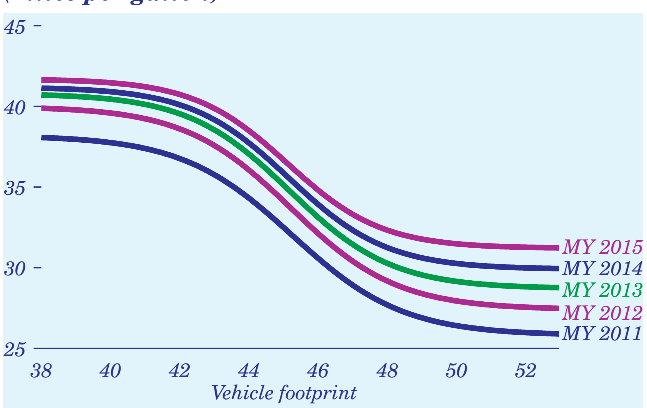
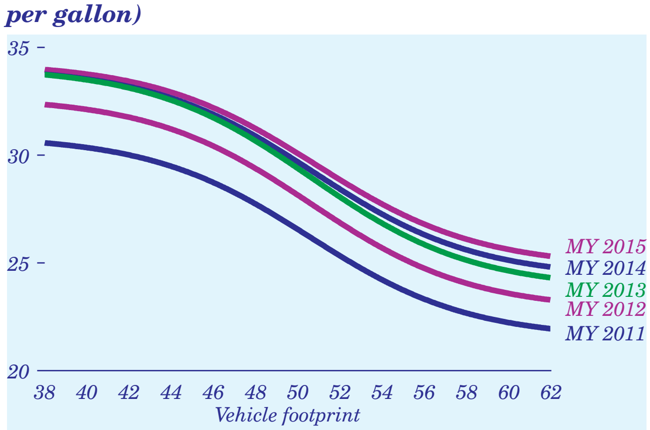


Figure 5. Proposed CAFE standards for light trucks by vehicle footprint, model years 2011-2015 (miles per gallon)



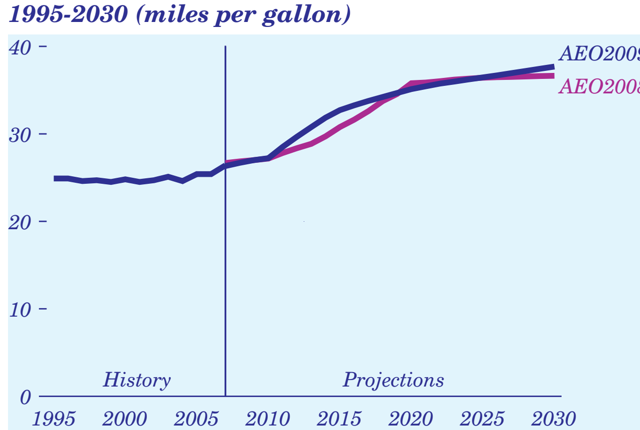
Regulations Related to the Outer Continental Shelf Moratoria and Implications of Not Renewing the Moratoria

From 1982 through 2008, Congress annually enacted appropriations riders prohibiting the Minerals Management Service (MMS) of the U.S. Department of the Interior from conducting activities related to leasing, exploration, and production of oil and natural

Table 1. Estimated fuel economy for light-duty vehicles, based on proposed CAFE standards, 2010-2015 (miles per gallon)

Model year	Passenger car	Light truck	Combined
2010	27.5	23.5	25.3
2011	31.2	25.0	27.8
2012	32.8	26.4	29.2
2013	34.0	27.8	30.5
2014	34.8	28.2	31.0
2015	35.7	28.6	31.6

Figure 6. Average fuel economy of new light-duty vehicles in the AEO2008 and AEO2009 projections, 1995-2030 (miles per gallon)



gas on much of the Federal OCS [*11*]. Further, a separate executive ban (originally put in place in 1990 by President George H.W. Bush and later extended by President William J. Clinton through 2012) also prohibited leasing on the OCS, with the exception of the Western Gulf of Mexico, portions of the Central and Eastern Gulf of Mexico, and Alaska. In combination, those actions prohibited drilling along the Atlantic and Pacific coasts, in the eastern Gulf of Mexico, and in portions of the central Gulf of Mexico. The Gulf of Mexico Energy Security Act of 2006 (Public Law 109-432) imposed yet a third ban on drilling through 2022 on tracts in the Eastern Gulf of Mexico that are within 125 miles of Florida, east of a dividing line known as the Military Mission Line, and in the Central Gulf of Mexico within 100 miles of Florida.

High oil and natural gas prices in recent years have affected policy toward oil and gas exploration and development of the OCS. On July 14, 2008, President Bush lifted the executive ban; and on September 30, 2008, Congress allowed the congressional ban to expire. Although the ban through 2022 on areas in the Eastern and Central Gulf of Mexico remains in place, lifting the executive and congressional bans removed key obstacles to development of the Atlantic and Pacific OCS.

Jurisdiction

The Submerged Lands Act (SLA) passed by Congress in 1953 established the Federal Government's title to submerged lands located on most of the OCS [*12*]. States were given jurisdiction over any natural resources within 3.45 miles (3 nautical miles) of the coastline, with the exception of Texas and the west coast of Florida, where the SLA extends the States' jurisdiction to 10.35 miles (9 nautical miles). The Outer Continental Shelf Lands Act (OCSLA), also passed in 1953, defined the OCS, separate from geologic definitions, as any submerged land outside State jurisdiction [*13*]. It also reaffirmed Federal jurisdiction over those waters and all resources therein. Further, it outlined Federal responsibilities for managing and maintaining offshore lands and authorized the Department of the Interior to formulate regulations pertaining to the leasing process and to lease the defined areas for exploration and development of OCS oil and natural gas resources.

The Coastal Zone Management Act of 1972 (CZMA) [*14*] gave States more input on activities in waters under Federal jurisdiction that affected their coastlines, encouraged coastal States to develop Coastal Zone Management Plans, and required State review of Federal actions, such as offshore leasing, that affect land and water use in their coastal areas. By virtue of the CZMA, States have the power to object to any Federal action that they deem inconsistent with their Coastal Zone Management Plan. At present, the vast majority of the U.S. coastline is covered by such plans.

MMS 5-Year Leasing Program

The OCSLA was amended in 1978 to establish specific leasing guidelines, which included the development of a 5-year leasing program. The purpose of the leasing program is to schedule all specified and proposed lease sales within a given 5-year period. The amendment also specifies a number of requirements on which the decision to include specific areas in the 5-year leasing program are to be based, including:

- Adequate information regarding the environmental, social, and economic effects of exploration and development in the area offered for lease must be considered, with no new leasing taking place if this information is not available.
- The timing and location of leasing must be based on geographic, geologic, and ecological characteristics of the region as well as location-specific risks, energy needs, laws, and stakeholder interests.
- The decisionmakers must seek balance between potential damage to the environment and coastal areas and potential energy supply.
- Areas with the greatest resource potential should have greater priority for development, particularly in areas where earlier development has proven a rich resource base.

For every 5-year leasing program, the MMS publishes a comprehensive document detailing the information and reasoning behind the leasing decisions. If a block is not included in the current 5-year leasing program, it may not be leased during the program. The first 5-year leasing program covered the period from 1980 to 1985; the current program covers the period from 2007 to 2012.

In anticipation of the possible lifting of the congressional moratorium after President Bush had lifted the executive moratorium, the MMS began initial steps toward the development of a new 5-year leasing program that would take into consideration the newly released areas. Development of the new program, which would go into effect in 2010 rather than 2012 as previously planned, began on August 1, 2008. Although its action would advance the start date for the next leasing plan by 2 years, the MMS cautioned that the development of a new 5-year leasing program remains a multi-step, multi-year process that includes three separate public comment periods, two separate draft proposals, and development of an environmental impact statement before completion of the final proposal. The final proposal must then be approved by the Secretary of the Interior. The MMS has indicated that a new 5-year leasing program could not go into effect until mid-2010, which would be the earliest that any block in the areas previously under moratoria could be offered for lease.

Leasing, Exploration, and Development

Once the 5-year leasing program is in place, the first lease sale can be offered. The actual leasing process will take 1 to 2 years, requiring preparation of draft and final environmental impact statements, periods of public comment, notices regarding the sale, approval from the governors of States bordering the area covered by the lease as mandated by the CZMA, a bidding period, the receipt and evaluation of bids, and the determination of winning bidders for each block offered for sale.

Successful bidders cannot simply begin operations when they have obtained a lease. An exploration plan must be developed and filed and must undergo technical and environmental review by the MMS before any drilling can commence. Only after obtaining the required approvals can the lease holder evaluate the area and conduct exploratory drilling, which can take from 1 to 3 years in the shallow offshore and up to 6 years in the deep offshore areas. When an initial discovery is made, a development plan must be filed for technical and environmental review by the MMS before any production can begin. Developmental drilling, along with necessary approvals, can take another 1 to 3 years. For major facilities, the MMS conducts on-site inspections, sometimes jointly with the U.S. Coast Guard, before production is allowed to begin. Air emissions permits and water discharge permits must also be obtained from the EPA. Thus, the total time required to obtain a lease, explore and develop the area, and begin actual production is between 4 and 12 years, or potentially more.

Revenue

Once awarded a lease, the lease holder pays a one-time fee plus annual rent for the right to develop the resources in the block. In addition, lease holders pay royalties to the MMS based on the value of any natural gas and oil actually produced. MMS, in turn, disburses the revenues to the appropriate Federal or State agencies. The amounts collected and distributed by the MMS in bonuses, rents, and royalties from Federal offshore oil and gas leases totaled $7.0 billion in fiscal year 2007 and $8.1 billion in fiscal year 2008 [*15*].

Under OCSLA, coastal States are entitled to 27 percent of the revenue from leases of any blocks in Federal waters that fall partially within 3 miles of the State's seaward jurisdictional boundary [*16*], a provision intended to compensate the States for any damage to or drainage from natural gas and oil resources in State waters that are adjacent to Federal leases. Between 1986 and 2003, coastal States received more than $3.1 billion in revenue from such leases [*17*].

In addition to the revenues defined by OCSLA, EPACT2005 allocated additional revenues to the States through the establishment of a new coastal impact assistance program that provides $250 million from OCS revenues per year for fiscal years 2007 to 2010 to six energy-producing coastal States: Alabama, Alaska, California, Louisiana, Mississippi, and Texas [*18*]. The Gulf of Mexico Energy Security Act of 2006 includes additional revenue-sharing provisions (for Alabama, Louisiana, Mississippi, and Texas and their coastal political subdivisions) for specific leases in the Central and Eastern Gulf of Mexico.

Future Directions

Considerable uncertainty still surrounds the issue of offshore drilling in previously restricted areas. Although the congressional moratorium was allowed to expire, some members of Congress have stated publicly that they will raise the issue again in 2009. They are joined by a number of groups and individuals who favor the moratorium and predict that it will be reinstated either partially or fully by the next Congress. Until further action is taken, however, the Atlantic and Pacific coasts are available to be leased, and offshore drilling in those areas could become a reality.

The key issue in developing the OCS is timing. A minimum of 4 years will be required before production from any new leases can begin, and many leases will require longer lead times. In addition, there is considerable uncertainty about the actual size of oil and natural gas resources in areas that have been or remain under moratorium. The actual level of technically recoverable resources also may differ from the current MMS mean resource estimate of approximately 14 billion barrels of oil and 85 trillion cubic feet of natural gas in the Atlantic and Pacific areas that were just opened for leasing. An estimated additional

3.7 billion barrels of oil and 21 trillion cubic feet of natural gas in the central and eastern Gulf of Mexico remain under moratorium through 2022 [*19*].

Loan Guarantee Program Established in EPACT2005

Title XVII of EPACT2005 [*20*] authorized DOE to issue loan guarantees to new or improved technology projects that avoid, reduce, or sequester GHGs. In 2006, DOE issued its first solicitation for $4 billion in loan guarantees for non-nuclear technologies. The issue of the size of the program was addressed subsequently in the Consolidated Appropriation Act of 2008 (the "FY08 Appropriations Act") passed in December 2008, which limited future solicitations to $38.5 billion and stated that authority to make the guarantees would end on September 30, 2009. The legislation also allocated the $38.5 billion cap as follows: $18.5 billion for nuclear plants; $6 billion for CCS technologies; $2 billion for advanced coal gasification units; $2 billion for "advanced nuclear facilities for the 'front end' of the nuclear fuel cycle"; and $10 billion for renewable, conservation, distributed energy, and transmission/ distribution technologies. DOE also was required to submit all future solicitations to both the House and Senate Appropriations Committees for approval [*21*].

DOE received all necessary approvals from Congress in the summer of 2008 and on June 30, 2008, issued two additional solicitations—one for nuclear plants and another for renewable, conservation, distributed energy, and transmission/distribution technologies [*22*, *23*]. Another solicitation, for advanced fossil fuel technologies, was issued on September 22, 2008 [*24*].

Even before it issued its 2008 solicitations, DOE had requested that Congress extend its authority to provide loan guarantees, originally set to expire at the end of fiscal year 2009, for an additional 2 years. As of November 2008, Congress had not acted on the request. Also, DOE's budget request for fiscal year 2009 indicated that only $2.2 billion in loan guarantees from the 2006 solicitation would be issued during that fiscal year. It is not clear what will happen to the rest of the program if DOE's loan guarantee authority expires as originally scheduled. *AEO2009* includes only the effects of the 2006 solicitation, which is assumed to result in the construction of 1.2 gigawatts of capacity at advanced coal-fired power plants and 250 megawatts at solar power plants [*25*].

Provisions of additional loan guarantees pursuant to the solicitations issued in 2008 could have a further effect on the projections, depending on whether the guarantees support projects that were already included in the *AEO2009* projections. For example, in October 2008 DOE received applications from 17 private and public power companies for 21 nuclear units (14 plants with a total of 28.8 gigawatts of capacity) in response to the nuclear solicitation [*26*]. In total, the utilities requested $122 billion in guarantees against total projected construction and financing costs of about $188 billion, suggesting that the $18.5 billion in the FY08 Appropriations Act could cover about 4.4 gigawatts of new nuclear capacity. *AEO2009* projects additions of 13 gigawatts of new nuclear capacity between 2000 and 2030.

Clean Air Mercury Rule

On February 8, 2008, a three-judge panel on the D.C. Circuit of the U.S. Court of Appeals issued a decision to vacate CAMR [*27*]. In its ruling, the panel cited the history of hazardous air pollutant regulation under Section 112 of the Clean Air Act (CAA) [*28*]. Section 112, as written by Congress, listed emitted mercury as a hazardous air pollutant that must be subject to regulation unless it can be proved harmless to public welfare and the environment. In 2000, the EPA ruled that mercury was indeed hazardous and must be regulated under Section 112 and, therefore, subjected to the best available control technology for mitigation.

CAMR was promulgated under Section 111 of the CAA, which allows for the use of a cap-and-trade approach rather than implementation of best available control technology. The EPA had delisted mercury from Section 112 without making the necessary findings to show that mercury emissions could be regulated under Section 111 without harming human health or the environment. The panel stated that the EPA overstepped its authority by ignoring Congressional guidelines and the agency's own earlier findings.

With the elimination of CAMR, there is no Federal mandate to regulate mercury emissions. Even before the rule was vacated, however, many States were adopting more stringent regulations that were allowed through an EPA waiver. Most of those regulations called for the application of best available control technology on all electricity generating units of a certain capacity. After the court's decision, more States imposed their own regulations.

At the time *AEO2009* was published, roughly one-half of the States, including most of those in the Northeast, had their own mercury mitigation laws in place. Without Federal monitoring requirements, however, some of the States that had previously passed regulations may have to make modest modifications in their guidelines. At present, electricity generating units in States without mercury laws are free to emit without limitations. Because the State laws differ, a rough estimate was created that generalized the various State programs into a format that could be used in NEMS, including a rough estimate of mercury emissions within each State. Moreover, the regulatory environment is extremely fluid, with many States planning to enact new laws or make their existing laws more stringent.

Clean Air Interstate Rule

CAIR is a cap-and-trade program promulgated by the EPA in 2005, covering 28 eastern U.S. States and the District of Columbia [*29*]. It was designed to reduce sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions in order to help States meet their National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter ($PM_{2.5}$) and to further emissions reductions already achieved through the Acid Rain Program and the NO_x State Implementation Plan call program. The rule was set to commence in 2009 for seasonal and annual NO_x emissions and in 2010 for SO_2 emissions.

On July 11, 2008, the U.S. District Court of Appeals court unanimously overturned CAIR, ruling that it could not be implemented under the CAA [*30*]. Electric utilities were caught off guard by the court's decision to vacate CAIR. Because the rule was less than 2 years away from implementation, many power plant owners already had spent billions of dollars on pollution control equipment [*31*]. In addition, many States were relying on reductions from CAIR to meet their NAAQS for $PM_{2.5}$ and ozone, and without the rule they might not be able to meet those requirements. The price of seasonal NO_x and SO_2 emissions allowances dropped significantly after the decision. The value of SO_2 allowances has fallen by 75 percent in 2008, and because there is no market for annual NO_x emissions allowances without CAIR, their price has dropped to zero.

Several actions are pending. On September 24, 2008, the U.S. Department of Justice (DOJ) and the EPA, along with several industry representatives and environmental groups, filed petitions in the Court of Appeals asking for the case to be reheard [*32*]. In the petition, the DOJ claimed that the statement in the court's decisions that CAIR was "fundamentally flawed" was incorrect. It also claimed that vacating CAIR could potentially "result in serious harms." The court is considering their petition. On October 21, 2008, the court asked for briefs from the main plaintiffs in the case, specifically asking whether they thought CAIR should be reinstated on an interim basis until updated regulations are issued [*33*]. This development raises the possibility that such a reinstatement could occur.

On December 23, 2008, the Court of Appeals issued a new ruling that remanded but did not vacate CAIR, noting that: "Allowing CAIR to remain in effect until it is replaced by a rule consistent with our opinion would at least temporarily preserve the environmental values" [*34*]. The change allows the EPA to modify CAIR to address the objections raised by the Court in its earlier decisions while leaving the rule in place. Because the ruling came well after the cutoff date for changes in Federal and State laws and regulation to be included in *AEO2009*, it is not reflected in the projections. Nonetheless, States still are required to meet their NAAQS, which will require emissions reductions. Therefore, it is assumed that all emissions limits in effect under CAIR remain in effect in the *AEO2009* reference case, but without the CAIR allowance trading provisions.

State Appliance Standards

State appliance standards have existed for decades, starting with California's enforcement of minimum efficiency requirements for refrigerators and several other products in 1979. In 1987, recognizing that different efficiency standards for the same products in different States could create problems for manufacturers, Congress enacted the National Appliance Energy Conservation Act (NAECA), which initially covered 12 products. The Energy Policy Act of 1992 (EPACT92), EPACT2005, and EISA2007 added additional residential and commercial products to the 12 products originally specified under NAECA.

Many different State appliance standards still exist today (Table 2); however, a key point of NAECA was to enforce Federal preemption of any State appliance standard. The preemption clause allows States to continue to mandate standards for products not covered by Federal law and to enforce standards that might have existed before Federal coverage, up to the date of Federal enforcement. Because most major appliances are covered by Federal law, the majority of State standards target less energy-intensive products. Most of the standards for products listed in Table 2 will be preempted by Federal standards within the next decade. For example, the California standard for general-service lighting will be preempted in 2012 by the Federal standard for general-service lighting required in EISA2007. States can petition DOE for a waiver to continue to enforce their own standards, as opposed to a less strict Federal standard. To date, however, no waivers have been granted.

The NEMS residential and commercial modules represent Federal appliance standards for all major appliances covered under NAECA and subsequent legislation. For products not explicitly covered in NEMS (residential dehumidifiers, for example), an off-line estimate of the impact of the standard is included in the projections by way of deducting the savings estimates from the projections without the standards included. Given that the NEMS buildings

Table 2. State appliance efficiency standards and potential future actions

State	Program (effective year of standard noted in parentheses)
AZ	Arizona's Minimum Appliance and Equipment Efficiency Standards currently apply to automatic commercial icemakers (2008) and metal halide lamp fixtures (2008). Every 3 years, the Energy Office of the Arizona Department of Commerce must conduct a comparative review and assessment of standards and submit a report of its findings and recommendations to the State legislature.
CA	California's Appliance Efficiency Regulations apply to automatic commercial ice makers (2006); commercial refrigerators and freezers (2003 phase I / 2006 phase II); consumer audio and video products (2006/2007); large packaged air conditioners above 20 tons (2006/2010); metal halide lamp fixtures (2006/2008); pool pumps (2006/2008); single-voltage external power supplies (2007/2008); general service incandescent lamps (2006); water dispensers (2003); walk-in refrigerators and freezers (2006); hot tubs (2006); commercial hot food holding cabinets (2006); under-cabinet fluorescent lamps (2006); and vending machines (2006). In addition, Assembly Bill 1109 requires a minimum efficiency standard for all general-purpose lights, with the goal of reducing energy use for indoor residential lighting to 50 percent of 2007 levels and for indoor commercial and outdoor lighting to 75 percent of 2007 levels by 2018.
CT	Connecticut efficiency standards apply to commercial refrigerators and freezers (2008) and large packaged air-conditioning equipment (2009). Standards must be reviewed biannually and increased if it is determined that higher efficiency standards would promote energy conservation and be cost-effective for consumers, and if multiple products would be available.
MD	Maryland's efficiency standards apply to bottle-type water dispensers (2009); commercial hot food holding cabinets (2009); metal halide lamp fixtures (2009); residential furnaces (2009); alternating current to direct current power supplies (2012/2013); State-regulated incandescent reflector lamps (2009); walk-in refrigerators and freezers (2009); commercial refrigeration cabinets (2010); and large packaged air-conditioning equipment (2010). Every 2 years the Maryland Energy Administration is directed to review and propose new standards to the Maryland Assembly for products not already subject to standards, or add more stringent amendments to existing standards.
MA	The Massachusetts appliance standards currently apply to medium-voltage dry-type transformers (2008); metal halide lamp fixtures (2009); residential furnaces and boilers (to be determined); residential furnace fans (to be determined); State-regulated incandescent reflector lamps (various types) (2008); and single-voltage external power supplies (2008). The State Department of Energy Resources (DOER) must file a biannual report on appliance efficiency standards, evaluating effectiveness and energy conservation. Existing Federal standards cover residential furnaces, boilers, and furnace fans; however, Massachusetts is seeking a waiver from the warm weather standard.
NV	Nevada's Assembly Bill 178 establishes efficiency standards for general-purpose lights (lamps, bulbs, tubes, or other illumination devices for indoor and outdoor use, not including lighting for people with special needs) to take effect between 2012 and 2015. Effective January 1, 2016, the Director of the Office of Energy must set a new minimum efficiency standard that exceeds the previous standard.
NY	New York efficiency standards currently not preempted by Federal legislation include consumer audio and video products (to be determined); digital television adapters (to be determined); metal halide lamp fixtures (2008); and single-voltage external power supplies (to be determined, preemption for some types starting in July 2008). New York law allows the Secretary of State, in consultation with the State Energy Research and Development Authority, to add additional products so long as they are commercially available, cost-effective, and not covered by Federal standards.
OR	Oregon efficiency standards currently not preempted by Federal legislation include automatic commercial icemakers (2008); metal halide fixtures (2008); single-voltage external power supplies (2007); and State-regulated incandescent reflector lamps (various types) (2007).
RI	Rhode Island efficiency standards not preempted by Federal standards include high-intensity discharge lamp ballasts (2007); single-voltage external power supplies (2008); metal halide lamp fixtures (2008); residential boilers and furnaces (to be determined); incandescent spot lights (2008); bottled water dispensers (2008); commercial hot food holding cabinets (2008); and walk-in refrigerators and freezers (2008). Rhode Island legislation allows for existing efficiency standards to be increased if the Chief of Energy and Community Services determines that it would promote energy conservation in the State and would be cost-effective for consumers.
VT	Vermont's Act Relating to Establishing Energy Efficiency Standards for Certain Appliances creates minimum standards for medium-voltage dry-type transformers (2008); metal halide lamp fixtures (2009); residential furnaces and boilers (to be determined); residential furnace fans (to be determined); single-voltage external power supplies (2008); and State-regulated incandescent reflector lamps (various types) (2008).
WA	Washington standards apply to automatic commercial ice makers (2008); commercial refrigerators and freezers (2007); metal halide lamp fixtures (2008); single-voltage external power supplies (2008); and State-regulated incandescent reflector lamps (various types) (2007). State efficiency legislation stipulates that standards may be increased or updated.

modules are specified at the Census Division level, State standards are not readily amenable to direct modeling in NEMS. Furthermore, the paucity of data at the State level does not allow for a direct accounting of equipment stock or energy usage, which is needed to estimate energy savings. Although NEMS does not represent State appliance standards explicitly, recent trends in energy intensity are taken into account in the projections and should represent recent State appliance efficiency standards to the extent that they affect future energy demand in the buildings sectors.

California's Move Toward E10

In *AEO2009*, E10—a gasoline blend containing 10 percent ethanol—is assumed to be the maximum ethanol blend allowed in California RFG, as opposed to the 5.7-percent blend assumed in earlier *AEO*s. The 5.7-percent blend had reflected decisions made when California decided to phase out use of the additive methyl tertiary butyl ether in its RFG program in 2003, opting instead to use ethanol in the minimum amount that would meet the requirement for 2.0 percent oxygen content under the CAA provisions in effect at that time [*35*].

Recently, there has been a push in California to increase the use of ethanol, for two reasons. First, the RFS mandate in EISA2007 Title II, Subtitle A [*36*], requires greater use of renewable fuels, such as ethanol. Second, California's Low Carbon Fuel Standard (LCFS) mandates a reduction in the State's overall GHG emissions to 1990 levels by 2020 and require a 10-percent reduction in GHG emissions from passenger vehicles by 2020. Although fuel providers can use a variety of strategies to produce lower carbon fuel, increasing the ethanol blends from 5.7 percent to 10 percent is thought to be a first step toward achieving the LCFS goals. In fact, in October 2008, CARB released its first draft of the LCFS regulatory framework [*37*]. The calculation in the framework assumes that the baseline emissions for gasoline in 2010 (from which CO_2 emissions must be reduced in later years) will be from E10 (California RFG with 10 percent ethanol content), implying that most, if not all, gasoline sold in California by 2010 will be E10.

Modifications were made to California's RFG regulations and the predictive model that estimates emissions for different fuel mixes in order to increase ethanol blends above 5.7 percent. The predictive model was revised to accommodate the higher ethanol blends in determining evaporative and exhaust emissions, providing the information needed by fuel providers to increase ethanol content. For example, the increased ethanol content will result in higher NO_x emissions, and the increase must be mitigated by lowering the fuel's sulfur content.

Refineries in California may have to make substantial modifications to produce compliant fuel under the new standards (most significantly, producing fuel with only 5 parts per million sulfur), and all fuel sold in California must be compliant with the new CARB Phase 3 standards after December 31, 2009. The final approved modifications in CARB Phase 3 gasoline and the revisions in the predictive model provide refiners and importers of fuel a formal framework with which to provide compliant fuel. Already, at least one major refiner has stated that it will apply the amended CARB Phase 3 gasoline standards, presumably to increase ethanol content.

State Renewable Energy Requirements and Goals: Update Through 2008

State RPS programs continue to play an important role in *AEO2009*, growing in number while existing programs are modified with more stringent targets. In total, 28 States and the District of Columbia now have mandatory RPS programs (Table 3), and at least 4 other States have voluntary renewable energy programs. In the absence of a Federal renewable electricity standard, each State determines its own levels of generation, eligible technologies, and noncompliance penalties. The growth in State renewable energy requirements has led to an expansion of renewable energy credit (REC) markets, which vary from State to State. Credit prices depend on the State renewable requirements and how easily they can be met.

In the *AEO2009* reference case, most States are projected to meet their RPS targets. California is an exception, as a result of limits on State funding for renewable projects. Therefore, for California, the cost of achieving each target increment is estimated, and the amount of renewable capacity that exhausts the renewable funding is assumed to be built. Renewable generation in most regions is approximated, because NEMS is not a State-level model, and each State represents only a portion of one of the NEMS regions. Compliance costs in each region are tracked, and the projection for total renewable generation is adjusted as needed to be consistent with the individual State provisions.

Table 3. State renewable portfolio standards

State	Program mandate
AZ	Arizona Corporate Commission Decision No. 69127 requires 15 percent of electricity sales to be renewable by 2025, with interim goals increasing annually. A specific percentage of the target must be from distributed generation. Multiple credits may be given for solar generation and in-State manufactured systems.
CA	Public Utilities Code Sections 399.11-399.20 mandate that 20 percent of electricity sales must be renewable by 2010. There are also goals for the longer term. Renewable projects with above-market costs will be funded by supplemental energy payments from a fund, possibly limiting renewable generation to less than the 20-percent requirement.
CO	House Bill 1281 sets the renewable target for investor-owned utilities at 20 percent by 2020. There is a 10-percent requirement in the same year for cooperatives and municipals. Moreover, 2 percent of total sales must be from solar power. In-State generation receives a 25-percent credit premium.
CT	Public Act 07-242 mandates a 27-percent renewable sales requirement by 2020, including a 4-percent mandate from higher efficiency or CHP systems. Of the overall total, 3 percent may be met by waste-to-energy facilities and conventional biomass.
DE	Senate Bill 19 determined the RPS to be 20 percent of sales by 2019. There is a separate requirement for solar generation (2 percent of the total), and compliance failure results in higher penalty payments. Solar technologies receive triple credits, and offshore wind receives 3.5 times the credit amount.
HI	Senate Bill 3185 sets the renewable mandate at 20 percent by 2020. All existing renewable facilities are eligible to meet the target, which has two interim milestones.
IL	Public Act 095-0481 created an agency responsible for overseeing the mandate of 25-percent renewable sales by 2025. There are escalating annual targets. and 75 percent of the requirements must be generated from wind. The plan also includes a cap on the incremental costs added from renewable penetration.
IA	An RPS mandating105 megawatts of renewable energy capacity has already been exceeded.
ME	In 2007, Public Law 403 added to the State's RPS requirements. Originally, a mandate of 30 percent renewable generation by 2000 was set to be lower than current generation. The new law requires a 10-percent increase in renewable capacity by 2017, and that level must be maintained in subsequent years. The years leading up to 2017 also have new capacity milestones.
MD	House Bill 375 revised the RPS to contain a 20-percent target by 2022, including a 2-percent solar target. Penalty payments for "Tier 1" compliance shortfalls were also raised to 4 cents per kilowatthour under the same legislation.
MA	The RPS has a goal of a 4-percent renewable share of total sales by 2009, with subsequent 1-percent annual increases to 2014. The State also has necessary payments for compliance shortfalls.
MI	Public Act 295 established an RPS that will require 10 percent renewable generation by 2015. Bonus credits are given to solar energy.
MN	Senate Bill 4 created a 30-percent renewable requirement by 2020 for Xcel, the State's largest supplier, and a 25-percent requirement by 2025 for others. Also specified was the creation of a State cap-and-trade program that will assist the program's implementation.
MO	Proposition C, approved by voters, mandates a 2-percent renewable energy requirement in 2011, which will increase incrementally to 15 percent of generation by 2021. Bonus credits are given to renewable generation within the State.
MT	House Bill 681 expanded the RPS provisions to all suppliers. Initially the law covered only public utilities. A 15-percent share of sales must be renewable by 2015. The State operates a REC market.
NV	The State has an escalating renewable target, established in 1997 and revised in 2005, that reaches 20 percent of total electricity sales by 2015. Up to one-quarter may be met through efficiency measures. There is also a minimum requirement for PV systems, which receive bonus credits.
NH	House Bill 873 legislated that 23.8 percent of electricity sales must be renewable by 2025, and 16.3 percent of total sales must be from renewable facilities that begin operation after 2006. Compliance penalties vary by generation type.
NJ	In 2006, the RPS was revised to increase renewable energy targets. The current level for renewable generation is 22.5 percent of sales by 2021, with interim targets. There are different requirements for different technologies, including a 2-percent solar mandate.
NM	Senate Bill 418 directs investor-owned utilities to have 20 percent of their sales from renewable generation by 2020. The renewable portfolio must consist of diversified technologies, with wind and solar each accounting for 20 percent of the target. There is a separate standard of 10 percent by 2020 for cooperatives.
NY	The Public Service Commission issued RPS rules in 2005 that call for an increase in renewable electricity sales to 24 percent of the total by 2013, from the current level of 19 percent. The program is administered and funded by the State.
NC	Senate Bill 3 created an RPS of 12.5 percent by 2021 for investor-owned utilities. There is also a 10-percent requirement by 2018 for cooperatives and municipals. Through 2018, 25 percent of the target may be met through efficiency standards, increasing to 40 percent in later years.
OH	Senate Bill 221 requires 25 percent of electricity to be produced from alternative energy resources by 2025, including low-carbon and renewable technologies. One-half of the target must come from renewable sources. Municipals and cooperatives are exempt.
OR	In June 2007, Senate Bill 838 required renewable targets of 25 percent by 2025 for large utilities and 5 to 10 percent by 2025 for smaller utilities. Any source of renewable electricity on line after 1995 is considered eligible. Compliance penalty caps have not yet been determined.
PA	The Alternative Energy Portfolio Standard has an18-percent requirement by 2020. Most of the qualifying generation must be renewable, but there is also a provision that allows certain coal resources to receive credits.
RI	The program requires that 16 percent of total sales be renewable by 2020. The interim program targets escalate more rapidly in later years. If the target is not met, a generator must pay an alternative compliance penalty.

(continued on page 22)

Table 3. State renewable portfolio standards (continued)

State	Program mandate
TX	Senate Bill 20 strengthened the State RPS by mandating 5,880 megawatts of renewable capacity by 2015. There is also a target of 500 megawatts of renewable capacity other than wind.
WA	Voters approved Initiative 937, which specifies that 15 percent of sales from the State's largest generators must come from renewable sources by 2020. There is an administrative penalty of 5 cents per kilowatthour for noncompliance. Generation from any facility that came on line after 1999 is eligible.
WI	Senate Bill 459 strengthened the State RPS with a requirement that, by 2015, each utility's renewable share of total generation must be at least 6 percentage points above the renewable share from 2001 to 2003. There is also a non-binding goal.

In 2008, three States (Michigan, Missouri, and Ohio) enacted new renewable legislation, and three others (Delaware, Maryland, and Massachusetts) modified existing legislation. Missouri's new RPS was approved by voters in the November 2008 election. In California, voters rejected two propositions that would have strengthened the State RPS. One would have increased the renewable requirement to 50 percent of electricity generated by 2025 and allowed for the use of a 20-year feed-in tariff [*38*]; the other would have established a $5 billion fund to support renewable electricity generation and transportation projects. The propositions were not supported by many environmentalists, who saw them as poorly written and potentially causing harm to the renewable industry. Both were defeated easily.

Michigan. Public Act 295 [*39*] established Michigan's first RPS. Signed into law in October 2008, the Act requires that all electricity suppliers generate 10 percent of their electricity from renewable sources by 2015. There are also intermediate benchmarks. Each supplier has its own standard, based on current levels of renewable generation. Coal-fired plants that sequester at least 85 percent of their emissions also qualify toward the target, as do all renewable technologies except new hydroelectric facilities; however, improvements on existing hydroelectric facilities will receive energy credits. Like most programs, Michigan's RPS will use RECs to promote compliance. Bonus credits are given to solar generators as well as facilities using in-State labor and manufactured equipment [*40*]. Up to 10 percent of the total requirement may be met through energy optimization and advanced system credits, which lower electricity demand.

Missouri. On November 4, 2008, voters approved Proposition C [*41*], changing Missouri's renewable goal into an enforceable mandate. The requirement goes into effect in 2011 with a 2-percent renewable target, which increases in four phases to reach the final 15-percent target by 2021. REC trading will be used, with in-State renewable generation eligible for 1.25 REC for each megawatthour of electricity generated. A small percentage of the overall renewable requirement must be met through solar generation. Suppliers subject to the RPS are required to offer their retail costumers a rebate of $2.00 per installed watt of small-scale solar systems.

Ohio. In May 2008, Ohio enacted legislation [*42*] that requires most retail electricity providers to produce 25 percent of their electricity from alternative energy resources by 2025. Alternatives are defined as low-carbon technologies, including nuclear energy and coal with carbon sequestration. Plants that come on line after 1998 are considered eligible toward meeting the target. Within the 25-percent requirement is a separate provision that increases the required renewable share of annual generation from 0.25 percent in 2009 to 12.5 percent in 2024. There are also energy efficiency and load-reducing requirements. Municipal and cooperative suppliers are exempt from all provisions.

REC trading is expected to help Ohio achieve its requirements. The REC prices will be capped at $45 per megawatthour, with more severe penalties incurred if the solar requirement is not met; however, there is also a provision that exempts suppliers from the mandates if they can show that they would incur incremental costs 3 percent above the total cost of a conventional alternative. Suppliers exempted from the annual requirement may have to meet stiffer compensatory targets in subsequent years.

Delaware. Senate Bill 328 [*43*] amended Delaware's existing RPS by awarding offshore wind 3.5 times as many credits as are received by conventional renewable technologies toward meeting the mandate. Analysis has shown that this provision makes offshore wind development economical under business-as-usual assumptions.

Maryland. House Bill 375 [*44*] increased the State's renewable energy requirement to 20 percent of total generation by 2022. The requirement must be met with resources classified in the legislation as "tier 1," which include all renewable forms of generation except existing large hydroelectric facilities. Senate Bill 348 [*45*], also enacted in 2008, expanded the definition of tier 1 resources to include "poultry litter-to-energy" facilities. Also included in the tier 1 resource target is a solar energy mandate that increases annually until it reaches 2 percent in 2022. Smaller amounts of electricity generated from tier 2 resources (large hydropower facilities) are included until 2019.

Along with its increased mandatory target, House Bill 375 includes higher compliance caps. A shortfall in renewable generation from tier 1 resources other than solar energy will cost a supplier 4 cents per kilowatthour. If it can be shown, however, that achieving the target would cost more than one-tenth of the supplier's total energy sales, the target may be deferred until the next year (an "off-ramp" that was added with the higher compliance caps in House Bill 375). Penalties for solar shortfalls are much larger, 45 cents per kilowatthour in the initial shortfall year, but they decrease by 5 cents annually until they reach and remain at 5 cents per kilowatthour beginning in 2023. Funds generated from the penalties will go to an energy investment fund for support of renewable energy technology advancement and deployment.

Massachusetts. The State RPS requirements are modeled through 2014 in *AEO2009*. Electricity suppliers in Massachusetts are required to increase their annual renewable generation from 4 percent of total generation in 2009 to 9 percent in 2014. The State DOER has the option of extending the 1-percent annual increase through 2020. Renewable requirements beyond 2014 are not assumed in *AEO2009*. In December 2008, the DOER enacted regulations establishing a target of 15 percent renewable generation by 2020, with the presumption of increasing the target thereafter. *AEO2009* is based on regulations in effect as of November 2008 and does not include the new target.

Updated State Air Emissions Regulations

Regional Greenhouse Gas Initiative

In September 2008, the first U.S. mandatory auction of CO_2 emission permits occurred among six States in the Northeast that are part of the Regional Greenhouse Gas Initiative (RGGI). The RGGI program includes 10 Northeastern States that have agreed to curtail and reverse growth in CO_2 emissions. It covers all electricity generating units with a capacity of at least 25 megawatts and requires them to hold an allowance for each ton of CO_2 emitted [*46*].

The first year of mandatory compliance is 2009 and each State's CO_2 "carbon budget" already has been determined. The budgets consist of historically based baselines with a cushion for emissions growth, so that meeting the cap is expected to be relatively easy initially and become more difficult over time. Overall, the RGGI region must maintain emissions of 188 million tons CO_2 for the next 5 years, followed by a mandatory 2.5-percent annual decrease through 2018, when the CO_2 emissions level should be 10 percent below the initial calculated budget. The requirements are expected to cover 95 percent of CO_2 emissions from the region's electric power sector. Each State has its own emissions budget, and the allowances will be auctioned at a uniform price across the entire region.

Before the first auction, several rules were agreed to by the States:

- Auctions will be held quarterly, following a single-round, sealed-bid format.
- Allowances will be sold at a uniform price, which is the highest price of the rejected bids.
- States may hold a small number of allowances for their own use; however, most States have decided to auction all their allowances.
- Each emitter must buy one allowance for every ton of CO_2 emitted.
- Future allowances will be made available for purchase up to 4 years before their official vintage date, as a way to control price fluctuations.
- A reserve price of $1.86 per allowance in real dollars will be in effect for each auction, as a way to preserve allowance prices in auctions where demand is low and to avoid collusion among emitters that could threaten a fair market.
- The revenue from the auctions can be spent at the State's discretion, although at least 25 percent must go to a fund that benefits consumers and promotes low-carbon energy development.

In the first auction, the six participating States (Connecticut, Maine, Maryland, Massachusetts, Rhode Island, and Vermont) sold 12,600,000 allowances at a price of $3.07 per allowance [*47*]. The next auction, held in December 2008, included the original six States along with New York, New Jersey, New Hampshire, and Delaware. Issues such as emission leakage [*48*], which is especially relevant in the Mid-Atlantic region, have been studied, but no specific solutions have been implemented.

RGGI is included in the *AEO2009* reference case. The effect is minimal in the early years, given the relatively generous emissions budget. Because it is difficult to capture the nuances of State initiatives in NEMS, which is a regional model, independent estimates were made for the Mid-Atlantic region to determine eligible generation facilities and their emissions caps (for Pennsylvania, an observing member that it is not participating in the cap-and-trade program and is not subject to any mandatory reductions, emissions are not restricted).

Western Climate Initiative

Developed independently of RGGI, the Western Climate Initiative (WCI) [*49*] is also a regional GHG reduction program. Participants in the WCI include seven U.S. States (Arizona, California, Montana, New Mexico, Oregon, Utah, and Washington) and four Canadian Provinces, with additional observer States and provinces in the United States, Canada, and Mexico.

The WCI seeks to reduce GHG emissions to levels 15 percent below 2005 emissions by 2020. Reductions will be achieved through an allowance cap-and-trade program, and each participating State or province will be able to determine its own allowance allocation method. Allowances will be based on a regionally agreed emissions estimate, likely taking into account some growth in GHG emissions through the first year of mandatory compliance in 2012. Although each jurisdiction will choose the specifics of allowance distribution, a minimum of 10 percent of allowances must be auctioned in 2012, and the requirement rises in subsequent years. In the initial compliance year, electricity generators and large industrial facilities in the WCI region, as well as outside facilities with energy products consumed in the region, will be required to provide one allowance for each ton of CO_2 equivalent released into the atmosphere.

WCI is similar to RGGI, but they also have important differences. Although the first phase of the WCI program (2012 to 2015) will not cover emissions from fossil fuels used in smaller facilities or in mobile sources, all fuels are expected to be covered by 2015, including those used in the transportation, industrial, and residential sectors (none of which is covered by RGGI in any period). All fuels will be regulated upstream at the distributor level. The 2015 cap will grow above the first phase cap, which covers only facilities emitting more than 10,000 tons CO_2 equivalent annually. Those sources will continue to be covered after the inclusion of combustion fuels, but the emissions will not be counted twice. Larger stationary facilities will be regulated at the emission source, and their fuels will not be subject to upstream regulation. Mandatory emissions monitoring of the stationary sources will begin in January 2010.

Another distinction is that the WCI will account for nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, not just CO_2 as in RGGI. The additional GHGs will be measured in terms of their CO_2-equivalent global warming potentials, and allowances will be issued accordingly. WCI documents estimate that 90 percent of the region's GHG emissions will be subject to regulation after additional combustion fuels are included in 2015.

Although no final caps have been determined, the permissible GHG ceiling will decline over the program, which currently ends in 2020. No formal determination of how to continue the program beyond 2020 has been made. In order to control the price of allowances, a reserve price will be set as the floor. Up to 49 percent of emissions reductions may occur through offset programs such as forestation and agriculture reform. The list of qualifying offsets remains to be determined but must be agreed on by all participants. There are still some details to be worked out between the WCI and the individual jurisdictions within the region that have their own GHG mitigation laws. Two prime examples are California, which has passed its own GHG legislation, and British Columbia, which is mitigating emissions through a tax. The issues will be addressed after the specifics of the program have been determined.

Unlike RGGI, the WCI is not included in the *AEO-2009* reference case, because the WCI model rules were released after November 2008. Similarly, the Midwestern Climate Initiative, which is in a preliminary stage, is not included in *AEO2009*. Regional and State GHG initiatives continue to evolve rapidly, and it is likely that *AEO2010* will include additional programs.

Endnotes for Legislation and Regulations

1. Including several ballot initiatives for energy-related legislation, where the results of the balloting are known.
2. For the complete text of the Food, Conservation, and Energy Act of 2008, see web site http://frwebgate.Access.gpo.gov/cgi-bin/getdoc.cgi?dbname=110_cong_public_laws&docid=f:publ246.110.pdf.
3. On December 23, 2008, after the November 2008 cutoff date for inclusion of changes in Federal and State laws and regulations in *AEO2009*, the United States Court of Appeals for the District of Columbia issued a new ruling that remanded but did not vacate CAIR, noting that "Allowing CAIR to remain in effect until it is replaced by a rule consistent with our opinion would at least temporarily preserve the environmental values." Source: United States Court of Appeals for the District of Columbia Circuit, No. 05-1244, web site www.epa.gov/airmarkets/progsregs/cair/docs/CAIRRemand Order.pdf. This change allows the EPA to modify CAIR to address the objections raised by the Court in its earlier decision while leaving the rule in place. The change is not reflected in *AEO2009*.
4. For complete text of the Emergency Economic Stabilization Act of 2008, including Division B, "Energy Improvement and Extension Act of 2008," see web site http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=110_cong_bills&docid=f:h1424enr.txt.pdf.
5. "Closed-loop" refers to fuels that are grown specifically for energy production, excluding wastes and residues from other activities, such as farming, landscaping, forestry, and woodworking.
6. Defense Energy Support Center, "Compilation of United States Fuel Taxes, Inspection Fees, and Environmental Taxes and Fees" (July 9, 2008).
7. U.S. Department of Transportation, National Highway Traffic Safety Administration, "Summary of Fuel Economy Performance," NHTSA-2007-28040-0001 (Washington, DC, March 2007), web site www.regulations.gov/fdmspublic/component/main?main=DocumentDetail&o=09000064802ad392.
8. U.S. Department of Transportation, National Highway Traffic Safety Administration, 49 CFR Parts 523, 531, 533, 534, 536, and 537 [Docket No. NHTSA-2008-0089] RIN 2127-AK29, *Notice of Proposed Rulemaking: Average Fuel Economy Standards Passenger Cars and Light Trucks Model Years 2011-2015* (Washington, DC, April 2008), pp. 14-15, web site www.nhtsa.dot.gov/portal/site/nhtsa/menuitem.43ac99aefa80569eea57529cdba046a0/.
9. A vehicle's footprint is defined as the wheelbase (the distance from the center of the front axle to the center of the rear axle) times the average track width (the distance between the center lines of the tires) of the vehicle in square feet.
10. U.S. Department of Transportation, National Highway Traffic Safety Administration, *Preliminary Regulatory Impact Analysis: Corporate Average Fuel Economy for MY 2011-2015 Passenger Cars and Light Trucks* (Washington, DC, April 2008), pp. 374-375, web site www.nhtsa.gov/staticfiles/DOT/NHTSA/Rulemaking/Rules/Associated%20Files/CAFE_2008_PRIA.pdf.
11. Most recently, the Consolidated Omnibus Appropriations Act of 2008 (Public Law 110-161, H.R. 2764) included the OCS moratorium as Sections 104, 105 and 412.
12. "OCS Lands Act History," web site www.mms.gov/aboutmms/OCSLA/ocslahistory.htm.
13. "OCS Lands Act History," web site www.mms.gov/aboutmms/OCSLA/ocslahistory.htm.
14. "Congressional Action to Help Manage Our Nation's Coasts," web site http://coastalmanagement.noaa.gov/czm/czm_act.html.
15. U.S. Department of the Interior, Minerals Management Service, "2001-Forward MRM Statistical Information: Reported Royalty Revenues," web site www.mrm.mms.gov/mrmwebstats/home.aspx.
16. See web site www.mms.gov/aboutmms/pdffiles/ocsla.pdf, p. 21, paragraph 1.
17. See web site www.mms.gov/ooc/newweb/publications/2003%20FACT.pdf, p. 7.
18. Energy Policy Act of 2005, Title III, Subtitle G, Section 384, "Coastal Impact Assistance Program," p. 147, web site www.epa.gov/oust/fedlaws/publ_109-058.pdf.
19. U.S. Department of the Interior, Minerals Management Service, *Report to Congress: Comprehensive Inventory of U.S. OCS Oil and Natural Gas Resources: Energy Policy Act of 2005—Section 357* (Washington, DC, February 2006), pp. v and vi, web site www.mms.gov/PDFs/2005EPAct/InventoryRTC.pdf.
20. For the complete text of the Energy Policy Act of 2005, see web site http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_public_laws&docid=f:publ058.109.pdf.
21. See *AEO2008* for more detailed discussion of the program and the FY 2008 Appropriations Act.
22. At the same time, DOE also issued a solicitation for the front end of the nuclear fuel cycle. Because NEMS does not contain a direct representation of the front end of the nuclear fuel cycle, that solicitation is not considered in this analysis.
23. U.S. Department of Energy, "DOE Announces Solicitation for $30.5 Billion in Loan Guarantees" (Washington, DC, June 30, 2008), web site www.lgprogram.energy.gov/press/063008.pdf.
24. U.S. Department of Energy, "DOE Announces Solicitation for $8.0 Billion in Loan Guarantees" (Washington, DC, September 22, 2008), web site www.lgprogram.energy.gov/press/092208.pdf.

25. A detailed discussion of the rationale for this assumption can be found in *AEO2008*. In brief, in 2007, DOE released technology-specific information about the requested guarantees from the 2006 solicitation. Included in that information were the requested dollar amounts of the guarantees, by technology. It was assumed, basically, that the dollar amounts of the approved guarantees would be proportional to the requested dollar amounts.
26. U.S. Department of Energy, "DOE Announces Loan Guarantee Applications for Nuclear Power Plant Construction" (Washington, DC, October 2, 2008), web site www.lgprogram.energy.gov/press/100208.pdf.
27. United States Court of Appeals for the District of Columbia Circuit, No. 05-1097, web site http://pacer.cadc.uscourts.gov/docs/common/opinions/200802/05-1097a.pdf.
28. "The Clean Air Act [As Amended Through P.L. 108–201, February 24, 2004]," web site http://epw.senate.gov/envlaws/cleanair.pdf.
29. U.S. Environmental Protection Agency, "Clean Air Interstate Rule," web site www.epa.gov/airmarkets/progsregs/cair/.
30. United States Court of Appeals for the District of Columbia Circuit, No. 05-1244, web site http://pacer.cadc.uscourts.gov/docs/common/opinions/200807/05-1244-1127017.pdf.
31. U.S. Environmental Protection Agency, web site www.epa.gov/airmarkets/progsregs/cair/docs/CAIR_Rehearing_Petition_as_Filed.pdf.
32. U.S. Environmental Protection Agency, web site www.epa.gov/airmarkets/progsregs/cair/docs/CAIR_Rehearing_Petition_as_Filed.pdf.
33. U.S. Environmental Protection Agency, web site www.epa.gov/airmarkets/progsregs/cair/docs/CAIR_Pet_Reply_Filed.pdf.
34. United States Court of Appeals for the District of Columbia Circuit, No. 05-1244, web site www.epa.gov/airmarkets/progsreg/cair/docs/CAIRRemandOrder.pdf.
35. The requirements for reformulated gasoline can be found in the 1990 Amendments to the Clean Air Act, Title II, Sec. 219 (web site www.epa.gov/oar/caa/caaa.txt). An excellent discussion of the history of oxygenate and other environmentally-based requirements for gasoline can be found in U.S. Environmental Protection Agency, *Fuel Trends Report: Gasoline 1995-2005*, EPA420-R-08-002 (Washington, DC, January 2008), web site www.epa.gov/otaq/regs/fuels/rfg/properf/420r08002.pdf.
36. Congressional Research Service, *Energy Independence and Security Act of 2007: A Summary of Major Provisions*, Order Code RL34294 (Washington, DC, December 2007), web site http://energy.senate.gov/public/_files/RL342941.pdf.
37. California Air Resources Board, "Low Carbon Fuel Standard Workshop: Review of the Draft Regulation" (October 16 2008), web site www.arb.ca.gov/fuels/lcfs/101608lcfsreg_prstn.pdf.
38. A feed-in-tariff guarantees a specified price, usually above the market level, on a long-term electricity purchasing agreement.
39. State of Michigan, 94th Legislature, Enrolled Senate Bill No. 213, web site www.legislature.mi.gov/documents/2007-2008/publicact/pdf/2008-PA-0295.pdf.
40. Although solar generation receives one bonus credit for each megawatthour produced, facilities using equipment manufactured in the same State and in-State workforces receive only 0.1 credit as a bonus.
41. Missouri Secretary of State, Amendment to Chapter 393 of the Revised Statutes of Missouri, Relating to Renewable Energy, web site www.sos.mo.gov/elections/2008petitions/2008-031.asp.
42. 127th General Assembly of the State of Ohio, Amended Substitute Senate Bill Number 221, web site www.legislature.state.oh.us/bills.cfm?ID=127_SB_0221.
43. State of Delaware, 144th General Assembly, Senate Bill 328, web site http://legis.delaware.gov/lis/lis144.nsf/vwLegislation/SB+328?Opendocument.
44. State of Maryland, House Bill 375, web site http://mlis.state.md.us/2008rs/billfile/HB0375.htm.
45. State of Maryland, Senate Bill 348, web site http://mlis.state.md.us/2008RS/billfile/SB0348.htm.
46. Regional Greenhouse Gas Initiative, "About RGGI," web site www.rggi.org/about/documents.
47. Regional Greenhouse Gas Initiative, "RGGI States' First CO_2 Auction Off to a Strong Start" (September 29, 2008), web site www.rggi.org/docs/rggi_press_9_29_2008.pdf.
48. Regional Greenhouse Gas Initiative, "Potential Emissions Leakage and the Regional Greenhouse Gas Initiative (RGGI)" (March 2008), web site http://rggi.org/docs/20080331leakage.pdf.
49. Western Climate Initiative, *Design Recommendations for the WCI Regional Cap-and-Trade Program* (September 23, 2008), web site www. westernclimate initiative.org/ewebeditpro/items/ O104F19865.PDF.

Issues in Focus

Introduction

This section of the *AEO* provides discussions on selected topics of interest that may affect future projections, including significant changes in assumptions and recent developments in technologies for energy production, supply, and consumption. Issues discussed this year include trends in world oil prices and production; the economics of plug-in electric hybrids; the impact of reestablishing the moratoria on oil and natural gas drilling on the Federal OCS; expectations for oil shale production; the economics of bringing natural gas from Alaska's North Slope to U.S. markets; the relationship between natural gas and oil prices; the impacts of uncertainty about construction costs for power plants; and the impact of extending the renewable PTC for 10 years. Last, in view of growing concerns about GHG emissions, the topics discussed also include the impacts of such concerns on investment decisions and their handling in *AEO2009*.

The topics explored in this section represent current, emerging issues in energy markets; however, many of the topics discussed in *AEO*s published in recent years remain relevant today. Table 4 provides a list of titles from the 2008, 2007, and 2006 *AEO*s that are likely to be of interest to today's readers. They can be found on EIA's web site at www.eia.doe.gov/oiaf/aeo/otheranalysis/aeo_analyses.html.

World Oil Prices and Production Trends in *AEO2009*

The oil prices reported in *AEO2009* represent the price of light, low-sulfur crude oil in 2007 dollars [*50*]. Projections of future supply and demand are made for "liquids," a term used to refer to those liquids that after processing and refining can be used interchangeably with petroleum products. In *AEO2009*, liquids include conventional petroleum liquids—such as conventional crude oil and natural gas plant liquids—in addition to unconventional liquids, such as biofuels, bitumen, coal-to-liquids (CTL), gas-to-liquids (GTL), extra-heavy oils, and shale oil.

Developments in the world oil market over the course of 2008 exemplify how the level and expected path of world oil prices can change even over a period of days, weeks, or months. The difficulty for projecting prices into the future continues when the period of interest extends through 2030. Long-term world oil prices are determined by four fundamental factors: investment and production decisions by the Organization of the Petroleum Exporting Countries (OPEC); the economics of non-OPEC conventional liquids supply; the economics of unconventional liquids supply; and world demand for liquids. Uncertainty about long-term world oil prices can be considered in terms of developments related to one or more of these factors.

Recent Market Trends

The first 6 months of 2008 saw the continuation of the previous years' increases in oil prices, spurred by rising demand that was satisfied by relatively high-cost exploration and production projects, such as those in ultra-deep water and oil sands, at a time when shortages in everything from skilled labor to steel were driving up costs of even the most basic production projects. An apparent lack of demand

Table 4. Key analyses from "Issues in Focus" in recent AEOs

AEO2008	*AEO2007*	*AEO2006*
Impacts of Uncertainty in Energy Project Costs	*Impacts of Rising Construction and Equipment Costs on Energy Industries*	*Economic Effects of High Oil Prices*
Limited Electricity Generation Supply and Limited Natural Gas Supply Cases	*Energy Demand: Limits on the Response to Higher Energy Prices in the End-Use Sectors*	*Changing Trends in the Refining Industry*
Trends in Heating and Cooling Degree-Days: Implications for Energy Demand	*Miscellaneous Electricity Services in the Buildings Sector*	*Energy Technologies on the Horizon*
Liquefied Natural Gas: Global Challenges	*Industrial Sector Energy Demand: Revisions for Non-Energy-Intensive Manufacturing*	*Advanced Technologies for Light-Duty Vehicles*
World Oil Prices and Production Trends in AEO2008	*Impacts of Increased Access to Oil and Natural Gas Resources in the Lower 48 Federal Outer Continental Shelf*	*Nonconventional Liquid Fuels*
	Alaska Natural Gas Pipeline Developments	*Mercury Emissions Control Technologies*
	Coal Transportation Issues	*U.S. Greenhouse Gas Intensity and the Global Climate Change Initiative*

response to high prices in developing countries, China and India in particular, led to expectations of continuing high oil prices and the bidding up of prices for the inputs needed to increase supply, such as labor, drilling rigs, and other factors. Given the apparent lack of consumer response to price increases, lags in increasing supply, and the limited availability of light crude oils, some analysts believed that a price of $200 per barrel was plausible in the near term.

By July 2008, when world oil prices neared $150 per barrel, it had become apparent that petroleum consumption in the first half of the year was lower than anticipated, and that economic growth was slowing. August saw the beginning of the current global credit crisis and a further weakening of demand; and since September 2008, the global economic downturn has reduced consumers' current and prospective near-term demand for oil while at the same time the global credit crunch has restricted the ability of some suppliers to raise capital for projects to increase future production.

In the second half of 2008, producer and consumer expectations regarding the imbalance of supply and demand in the world oil market were essentially reversed. Before August, market expectations for the future economy indicated that demand would outpace supply despite planned increases in production capacity. After September, expectations became so dismal that OPEC's October 24 announcement of a 1.5-million-barrel-per-day production cut was followed by a drop in oil prices.

Although the impacts of the current economic downturn and credit crisis on petroleum demand are likely to be large in the near term, they also are likely to be relatively short-lived. National economies and oil demand are expected to begin recovering in 2010. In contrast, their impacts on oil production capacity probably will not be realized until the 2010-2013 period, when current new investments in capacity, had they been made, would have begun to result in more oil production. As a result, just at the time when demand is expected to recover, physical limits on production capacity could lead to another wave of price increases, in a cyclical pattern that is not new to the world oil market.

Long-Term Prospects

Developments in past months demonstrate how quickly and drastically the fundamentals of oil prices and the world liquids market as a whole can change. Within a matter of months, the change in current and prospective world liquids demand has affected the perceived need for additional access to conventional resources and development of unconventional liquids supply and reversed OPEC production decisions. The price paths assumed in *AEO2009* cover a broad range of possible future scenarios for liquids production and oil prices, with a difference of $150 per barrel (in real terms) between the high and low oil price cases in 2030. Although even that large difference by no means represents the full range of possible future oil prices, it does allow EIA to analyze a variety of scenarios for future conditions in the oil and energy markets in comparison with the reference case.

Reference Case

The *AEO2009* reference case is a "business as usual" trend case built on the assumption that, for the United States, existing laws, regulations, and practices will be maintained throughout the projection period. The reference case assumes that growth in the world economy and liquids demand will recover by 2010, with growth beginning in 2010 and continuing through 2013, when world demand for liquids surpasses the 2008 level. In the longer term, world economic growth is assumed to be roughly constant, and demand for liquids returns to a gradually increasing long-term trend. As the global recession fades, oil prices (in real 2007 dollars) begin rebounding, to $110 per barrel in 2015 and $130 per barrel in 2030.

Meeting the long-term growth of world liquids demand requires higher cost supplies, particularly from non-OPEC producers, as reflected in the reference case by a 1.1-percent average annual increase in the world oil price after 2015. Increases from OPEC producers will also be needed, but the organization is assumed to limit its production growth so that its share of total world liquids supply remains at approximately 40 percent.

The growth in non-OPEC production comes primarily from increasingly high-cost conventional production projects in areas with inconsistent fiscal or political regimes and from expensive unconventional liquids production projects. The return to historically high price levels would encourage the continuation of recent trends toward "resource nationalism," with foreign investors having less access to prospective areas, less attractive fiscal regimes, and higher exploration and production costs than in the first half of this decade.

Low Price Case

The *AEO2009* low price case assumes that oil prices remain at $50 per barrel between 2015 and 2030. The low price case assumes that free market competition and international cooperation will guide the development of political and fiscal regimes in both consuming and producing nations, facilitating coordination and cooperation between them. Non-OPEC producers are expected to develop fiscal policies and investment regulations that encourage private-sector participation in the development of their resources. OPEC is assumed to increase its production levels, providing 50 percent of the world's liquids in 2030. The availability of low-cost resources in both non-OPEC and OPEC countries allows prices to stabilize at relatively low levels, $50 per barrel in real 2007 dollars, and reduces the impetus for consuming nations to invest in the production of unconventional liquids as heavily as in the reference case.

High Price Case

The *AEO2009* high price case assumes not only that there will be a rebound in oil prices with the return of world economic growth but also that they will continue escalating rapidly as a result of long-term restrictions on conventional liquids production. The restrictions could arise from political decisions as well as resource limitations. Major producing countries, both OPEC and non-OPEC, could use quotas, fiscal regimes, and various degrees of nationalization to increase their national revenues from oil production. In that event, consuming countries probably would turn to high-cost unconventional liquids to meet some of their domestic demand. As a result, in the high price case, oil prices rise throughout the projection period, to a high of $200 per barrel in 2030. Demand for liquids is reduced by the high oil prices, but the demand reduction is overshadowed by severe limitations on access to, and availability of, conventional resources.

Components of Liquid Fuels Supply

In the reference case, total liquid fuels production in 2030 is about 20 million barrels per day higher than in 2007 (Table 5). Decisions by OPEC member countries about investments in new production capacity for conventional liquids, along with limitations on access to non-OPEC conventional resources, limit the increase in production to 11.3 million barrels per day, and their share of total global liquid fuels supply drops from 96 percent in 2007 to 88 percent in 2030.

Global production of unconventional petroleum liquids rises in the reference case. Production from Venezuela's Orinoco belt and Canada's oil sands increases but remains less than is economically viable because of access restrictions in Venezuela and environmental concerns in Canada. As a result, unconventional petroleum liquids production increases by only 3.6 million barrels per day, to 6 percent of global liquid fuels supply in 2030. Relatively high prices also encourage growth in production of CTL, GTL, biofuels, and other nonpetroleum unconventional liquids (which include stock withdrawals, blending components, other hydrocarbons, and ethers) from 1.7 million barrels per day in 2007 to 7.4 million barrels per day (7 percent of total liquids supplied) in 2030.

In the low price case, from 2015 to 2030, oil prices are on average almost 60 percent lower than in the reference case. As described above, a lower price path could be caused by increased access to resources in non-OPEC countries and decisions by OPEC member countries to expand their production. In the low price case, conventional crude oil production rises to 93.6 million barrels per day in 2030, the equivalent of

Table 5. Liquid fuels production in three cases, 2007 and 2030 (million barrels per day)

		2030		
Projection	***2007***	***Reference***	***Low oil price***	***High oil price***
Conventional liquids				
Conventional crude oil and lease condensate	71.0	77.3	93.6	57.7
Natural gas plant liquids	8.0	12.4	11.2	12.1
Refinery gain	2.1	2.7	3.2	2.1
Subtotal	***81.1***	***92.4***	***108.1***	***71.9***
Unconventional liquids				
Oil sands, extra-heavy crude oil, shale oil	2.0	5.6	6.7	6.1
Coal-to-liquids, gas-to-liquids	0.2	1.6	0.8	2.8
Biofuels	1.2	5.4	3.3	7.7
Other	0.3	0.4	0.4	0.4
Subtotal	***3.7***	***13.0***	***11.2***	***17.0***
Total	***84.8***	***105.4***	***119.3***	***88.9***

89 percent of total liquids production in 2030 in the reference case. Total conventional liquids production in the low price case rises above 100 million barrels per day in 2024 and continues upward to 108.1 million barrels per day in 2030.

Production of unconventional petroleum liquids is also higher in the low price case than in the reference case, despite their generally higher costs. The increase is based on assumed changes in access to resources. In the low price case, Venezuela's production of extra-heavy oil in 2030 increases to 3.0 million barrels per day, compared with 1.2 million barrels per day in the reference case—a 150-percent increase that more than compensates for a decrease of 0.5 million barrels per day in production from Canada's oil sands. As a result, total production of unconventional petroleum liquids in 2030 is 1.1 million barrels per day higher in the low price case than in the reference case. Production of CTL, GTL, biofuels, and other unconventional liquids in 2030 (primarily in the United States, China, and Brazil) is 2.9 million barrels per day lower than in the reference case, because the profitability of such projects is reduced.

In the high price case, from 2015 to 2030, oil prices average 56 percent more than in the reference case because of severe restrictions on access to non-OPEC conventional resources and reductions in OPEC production. Conventional liquids production in 2030 is 71.9 million barrels per day, down by 9.2 million barrels per day from 2007 production. Access limitations also constrain production of Venezuelan extra-heavy oil, which in 2030 totals 0.8 million barrels per day, or 0.4 million barrels per day less than in the reference case. Production of unconventional liquids from Canada's oil sands in 2030 is 0.9 million barrels per day higher than in the reference case, however, at 5.1 million barrels per day in 2030, which more than makes up for the decrease in production of extra-heavy oil.

Production of CTL, GTL, biofuels, and other unconventional liquids totals 3.5 million barrels per day more in 2030 in the high price case than in the reference case, primarily because China's CTL production in 2030 is approximately 0.8 million barrels per day more than in the reference case, and Brazil's biofuels production is 1.0 million barrels per day more than in the reference case. In the United States, GTL production starts in 2017 and increases to 0.4 million barrels per day in 2030 in the high oil price case.

Economics of Plug-In Hybrid Electric Vehicles

PHEVs have gained significant attention in recent years, as concerns about energy, environmental, and economic security—including rising gasoline prices—have prompted efforts to improve vehicle fuel economy and reduce petroleum consumption in the transportation sector. PHEVs are particularly well suited to meet these objectives, because they have the potential to reduce petroleum consumption both through fuel economy gains and by substituting electric power for gasoline use.

PHEVs differ from both conventional vehicles, which are powered exclusively by gasoline-powered internal combustion engines (ICEs), and battery-powered electric vehicles, which use only electric motors. PHEVs combine the characteristics of both systems.

Current PHEV designs use battery power at the start of a trip, to drive the vehicle for some distance until a minimum level of battery power is reached (the "minimum state of charge"). When the vehicle has reached its minimum state of charge, it operates on a mixture of battery and ICE power, similar to some hybrid electric vehicles (HEVs) currently in use. In charge-depleting operation, a PHEV is a fully functioning electric vehicle. Some HEVs also can operate in charge-depleting operation, but only for limited distances and at low speeds. Also, PHEVs can be engineered to run in a blended mode of operation, where an onboard computer determines the most efficient use of battery and ICE power.

PHEVs are unique in that their batteries can be recharged by plugging a power cord into an electrical outlet. The distance a PHEV can travel in all-electric (charge-depleting) mode is indicated by its designation. For example, a PHEV-10 is designed to travel about 10 miles on battery power alone before switching to charge-sustaining operation.

Although PHEV purchase decisions may be based in part on concerns about the environment or national energy security, or by a preference for the newest vehicle technology, a comprehensive evaluation of the potential for wide-scale penetration of PHEVs into the LDV transportation fleet requires, among other things, an analysis of economic costs and benefits for typical consumers. In general, consumers will be more willing to purchase PHEVs rather than conventional gasoline-powered vehicles if the economic benefits of doing so exceed the costs incurred. Therefore, an understanding of the economic benefits and costs of purchasing a PHEV is, in general, a fundamental factor in determining the potential for consumer acceptance that would allow PHEVs to compete seriously in LDV markets.

The major economic benefit of purchasing a PHEV is its significant fuel efficiency advantage over a conventional vehicle (Table 6). The PHEV can use rechargeable battery power over its all-electric range before entering charge-sustaining mode, and its all-electric operation is more energy-efficient than either a conventional ICE vehicle or the hybrid mode of an HEV (or the hybrid operation of the PHEV itself).

On a gasoline-equivalent basis (with electricity efficiency estimated "from the plug") a PHEV's charge-depleting battery system gets on average about 105 mpg, well above even the most efficient petroleum-based ICE. When the PHEV enters charge-sustaining mode, it also takes advantage of its hybrid ICE-battery operation to achieve a relatively efficient 42 mpg. As a result, the total annual fuel expenditures for a PHEV, combining both electricity costs and gasoline, are lower than those of a conventional ICE vehicle using gasoline. The fuel savings are amplified when the PHEV's all-electric range is increased, when gasoline prices are high, or when the difference between gasoline prices and electricity prices increases (Figure 7).

Although the lower fuel costs of PHEVs provide an obvious economic benefit, currently they are significantly more expensive to buy than a comparable conventional vehicle. The price difference results from the costs of the PHEV's battery pack and the hybrid system components that manage the use and storage of electricity. The incremental cost of the battery pack depends on its storage capacity, power output, and chemistry. For example, the electricity storage requirements for a PHEV-40, designed to travel about 40 miles on battery power alone before switching to charge-sustaining operation, are considerably larger than those for a PHEV-10. In terms of power output, PHEV batteries will be engineered to meet the typical performance needs of LDVs, such as acceleration.

Currently two competing chemistries are seen as viable options for PHEV batteries—nickel metal hydride (NiMH) and lithium-ion (Li-Ion)—with different strengths and weaknesses. NiMH batteries are cheaper to produce per kilowatthour of capacity and have a proven safety record; however, their relative weight may limit their use in PHEVs. Li-Ion batteries have the potential to store significantly more electricity in lighter batteries; however, their use in PHEVs currently is limited by concerns about their calendar life, cycle life, and safety. Different vehicle manufacturers have reached different conclusions about which battery chemistry they will use in their initial PHEV offerings, but the majority consensus is that Li-Ion batteries have the most promise for the long term [*51*], and in this analysis they are assumed to be the battery of choice.

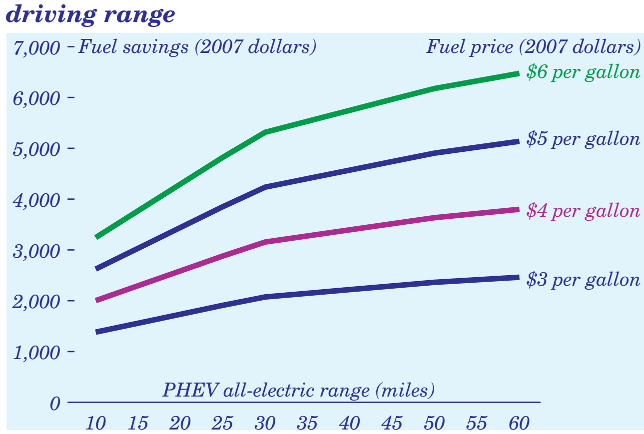
The second cost element associated with PHEVs is the cost of the additional electronic components and hardware required to manage vehicle electrical systems and provide electrical motive power. The

Table 6. Assumptions used in comparing conventional and plug-in hybrid electric vehicles

Characteristics	*Conventional ICE*[a]	*PHEV*[b]
Fuel efficiency (miles per gallon of gasoline equivalent)	*35*	*105 (charge-depleting mode) 42 (charge-sustaining mode)*
Discount rate	*10 percent*	*10 percent*
Discount period	*6 years*	*6 years*
Annual vehicle-miles traveled	*14,000*	*14,000*
Electricity price per kilowatthour	*—*	*$0.10*

[a]*Light-duty vehicle with gasoline-powered internal combustion engine.*
[b]*Light-duty vehicle with lithium-ion battery for charge-depleting mode and hybrid gasoline-powered internal combustion and battery engine for charge-sustaining mode.*

Figure 7. Value of fuel saved by a PHEV compared with a conventional ICE vehicle over the life of the vehicles, by gasoline price and PHEV all-electric driving range



conventional vehicle systems on a PHEV may be less costly than those on conventional gasoline vehicles, because the PHEV's engine and (if required) transmission are smaller, but the saving is negated by the additional costs associated with the electric motor, power inverter, wiring, charging components, thermal packaging to prevent battery overheating, and other parts.

An example of the differences in various vehicle system costs (excluding the battery pack) between a PHEV-20, designed to travel about 20 miles on battery power alone before switching to charge-sustaining operation, and a similar conventional vehicle is shown in Table 7 [*52*]. The estimated incremental cost of the PHEV-20 shown in the table represents the combined incremental costs of all vehicle systems other than the battery, at production volumes expected in 2020 or 2030.

The combined costs of the PHEV battery and battery supporting systems together represent the total incremental costs of a PHEV compared to a conventional gasoline vehicle. In the long run, however, the costs of PHEV battery and vehicle systems are not expected to remain static. Successes in research and development are expected to improve battery characteristics and reduce costs over time. In addition, as more Li-Ion batteries and system components are produced, manufacturers are expected to improve production techniques and decrease costs through economies of scale (Figure 8).

Table 7. Conventional vehicle and plug-in electric hybrid system component costs for mid-size vehicles at volume production (2007 dollars)

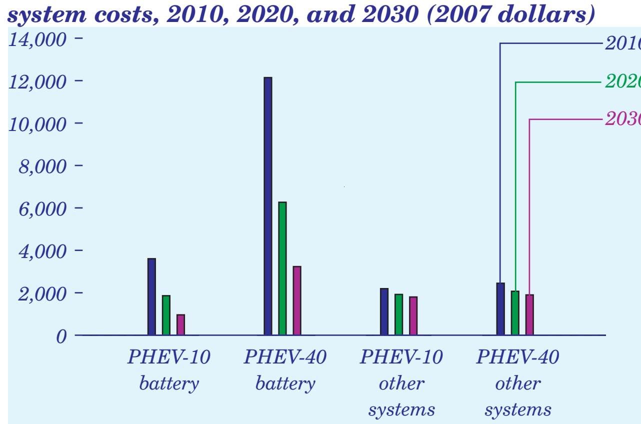
Vehicle component	*Conventional ICE*	*PHEV-20*
Engine/exhaust	*2,357*	*1,370*
Transmission	*1,045*	*625*
Accessory power	*210*	*300*
Electric traction	*40*	*1,542*
Starter motor	*40*	*—*
Electric motor	*—*	*893*
Power inverter	*—*	*528*
Electronics thermal	*—*	*121*
On-vehicle charging system	*—*	*460*
Other battery/storage costs	*30*	*809*
Fuel storage (tank)	*10*	*10*
Accessory battery	*20*	*15*
Pack tray	*—*	*170*
Pack hardware	*—*	*500*
Battery thermal	*—*	*114*
Total	***3,682***	***5,106***
PHEV incremental cost	***—***	***1,424***

To incentivize purchases of initial PHEV offerings, the recently passed EIEA2008 grants a tax credit of $2,500 for PHEVs with at least 4 kilowatthours of battery capacity (about the size of a PHEV-10 battery), with larger batteries earning an additional $417 per kilowatthour up to a maximum of $7,500 for light-duty PHEVs, which would be reached at a battery size typical for a PHEV-40 [*53*]. The credit will apply until 250,000 eligible PHEVs are sold or until 2015, whichever comes first.

ARRA2009, which was enacted in February 2009, modifies the PHEV tax credit so that the minimum battery size earning additional credits is 5 kilowatthours and the maximum allowable credit based on battery size remains unchanged at $5,000. ARRA2009 also extends the number of eligible vehicles from a cumulative total of 250,000 for all manufacturers to more than 200,000 vehicles per manufacturer, with no expiration date on eligibility. After a manufacturer's cumulative production of eligible PHEVs reaches 200,000 vehicles, the tax credits are reduced by 50 percent for the preceding 2 quarters and to 25 percent of the initial value for the preceding third and fourth quarters. ARRA2009 is not considered in *AEO2009*.

As a result of the EIEA2008 tax credit, the combined cost of a PHEV battery and PHEV system in 2010 will be lower than it would be without the credit. Moreover, even after the credit has expired, incentivizing the purchase of PHEVs in the near term will allow both battery and battery-system manufacturers to achieve earlier economies of scale through greater initial sales, thus allowing battery and systems costs to decline more quickly than would have been the case without the tax credit. As a result, the combined incremental costs for PHEVs are expected to be

Figure 8. PHEV-10 and PHEV-40 battery and other system costs, 2010, 2020, and 2030 (2007 dollars)



significantly lower in 2030, when economies of scale and learning have been fully realized (Figure 9).

A typical consumer may be willing to purchase a PHEV instead of a conventional ICE vehicle when the economic benefit of reduced fuel expenditures is greater than the total incremental cost of the PHEV. On that basis, PHEVs face a significant challenge. Even in 2030, the additional cost of a PHEV is projected to be higher than total fuel savings unless gasoline prices are around $6 per gallon (Figure 10). In the meantime, the cost challenge for PHEVs is even greater (Figure 11), which leads to an important problem: if consumers do not choose to buy PHEVs because they are not cost-competitive with conventional vehicles in the near term, then PHEV sales volumes will not be sufficient to induce the economies of scale assumed for this analysis.

In addition to the economic challenge, PHEVs also face uncertainty with respect to Li-Ion battery life and safety [*54*]. Further, they will continue to face competition from other vehicle technologies, including diesels, grid-independent gasoline-electric hybrids, FFVs, and more efficient conventional gasoline vehicles, all of which are likely to become more fuel-efficient in the next 20 years.

Future advances in Li-Ion battery technology could address economic, lifetime, and safety concerns, paving the way for large-scale sales and significant penetration of PHEVs into the U.S. LDV fleet. For example, a technological breakthrough could conceivably allow for smaller batteries with the same capacity and power output, thus lowering incremental costs and making PHEVs attractive on a cost-benefit basis. Also, there are at least two non-economic arguments in favor of PHEVs. First, PHEVs could significantly reduce GHG emissions in the transportation

Figure 9. Incremental cost of PHEV purchase with EIEA2008 tax credit included compared with conventional ICE vehicle purchase, by PHEV all-electric driving range, 2010, 2020, and 2030 (2007 dollars)

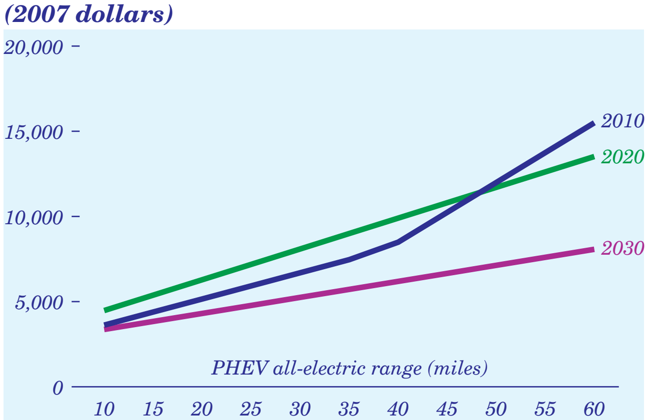


Figure 10. PHEV fuel savings and incremental vehicle cost by gasoline price and PHEV all-electric driving range, 2030 (2007 dollars)

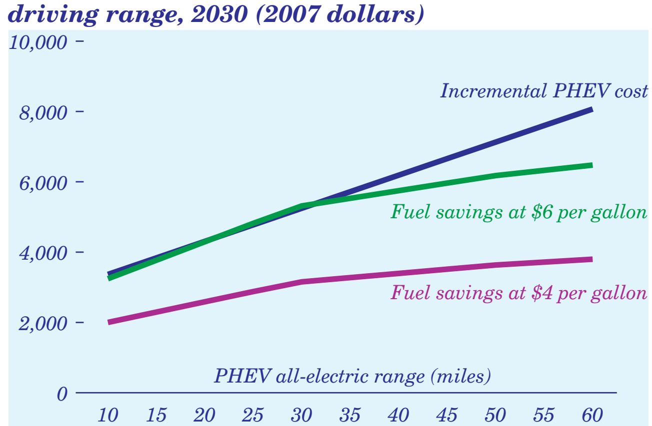


Figure 11. PHEV fuel savings and incremental vehicle cost by gasoline price and PHEV all-electric driving range, 2010 and 2020 (2007 dollars)

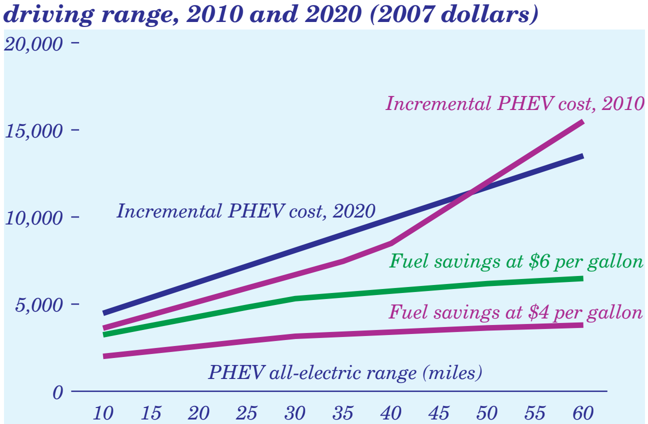
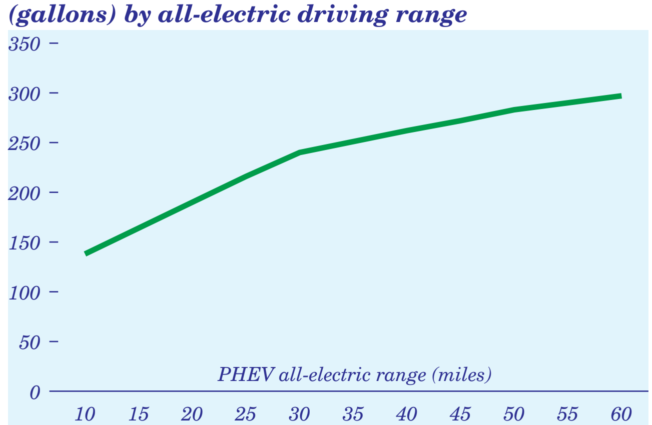


Figure 12. PHEV annual fuel savings per vehicle (gallons) by all-electric driving range



sector, depending on the fuels used to produce electricity. Second, PHEVs use less gasoline than conventional ICE vehicles (Figure 12). If PHEVs displaced conventional ICE vehicles, U.S. petroleum imports could be reduced [*55*].

Impact of Limitations on Access to Oil and Natural Gas Resources in the Federal Outer Continental Shelf

The U.S. offshore is estimated to contain substantial resources of both crude oil and natural gas, but until recently some of the areas of the lower 48 OCS have been under leasing moratoria [*56*]. The Presidential ban on offshore drilling in portions of the lower 48 OCS was lifted in July 2008, and the Congressional ban was allowed to expire in September 2008, removing regulatory obstacles to development of the Atlantic and Pacific OCS [*57*, *58*].

Although the Atlantic and Pacific lower 48 OCS regions are open for exploration and development in the *AEO2009* reference case, timing issues constrain the near-term impacts of increased access. The U.S. Department of Interior, MMS, is in the process of developing a leasing program that includes selected tracts in those areas, with the first leases to be offered in 2010 [*59*]; however, there is uncertainty about the future of OCS development. Environmentalists are calling for a reinstatement of the moratoria. Others cite the benefits of drilling in the offshore. Recently, the U.S. Department of the Interior extended the period for comment on oil and natural gas development on the OCS by 180 days and established other processes to allow more careful evaluation of potential OCS development.

Assuming that leasing actually goes forward on the schedule contemplated by the previous Administration, the leases must then be bid on and awarded, and the wining bidders must develop exploration and development plans and have them approved before any wells can be drilled. Thus, conversion of the newly available OCS resources to production will require considerable time, in addition to financial investment. Further, because the expected average field size in the Pacific and Atlantic OCS is smaller than the average field size in the Gulf of Mexico, a portion of the additional OCS resources may not be as economically attractive as available resources in the Gulf.

Estimates from the MMS of undiscovered resources in the OCS are the starting point for EIA's estimate of the OCS technically recoverable resource. Adding the mean MMS estimate of undiscovered technically recoverable resources to proved reserves and inferred resources in known deposits, the remaining technically recoverable resource (as of January 1, 2007) in the OCS is estimated to be 93 billion barrels of crude oil and 456 trillion cubic feet of natural gas (Table 8). The OCS areas that were until recently under moratoria in the Atlantic, Pacific, and Eastern/Central Gulf of Mexico are estimated to hold roughly 20 percent (18 billion barrels) of the total OCS technically recoverable oil—10 billion barrels in the Pacific and nearly 4 billion barrels each in the Eastern/Central Gulf of Mexico and Atlantic OCS. Roughly 76 trillion cubic feet of natural gas (or 17 percent) is estimated to be in areas formerly under moratoria, with nearly 37 trillion cubic feet in the Atlantic, 18 trillion cubic feet in the Pacific, and 21 trillion cubic feet in the Eastern/Central Gulf of Mexico. It should be noted that there is a greater degree of uncertainty about resource estimates for most of the OCS acreage previously under moratoria, owing to the absence of previous exploration and development activity and modern seismic survey data.

To examine the potential impacts of reinstating the moratoria, an OCS limited case was developed for

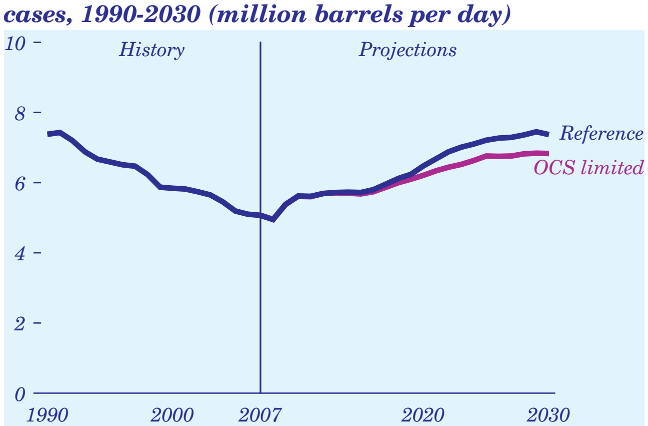
Table 8. Technically recoverable resources of crude oil and natural gas in the Outer Continental Shelf, as of January 1, 2007

Resource area and category	*Crude oil (billion barrels)*	*Natural gas (trillion cubic feet)*
Undiscovered resources		
Gulf of Mexico	*34.29*	*183.21*
Eastern and Central Gulf of Mexico (earliest leasing in 2022)	*3.65*	*21.46*
Pacific (earliest leasing in 2010)	*10.50*	*18.43*
Atlantic (earliest leasing in 2010)	*3.92*	*36.50*
Alaska	*26.61*	*132.06*
Total undiscovered	***78.97***	***391.66***
Proved reserves		
Gulf of Mexico	*3.66*	*14.55*
Pacific	*0.44*	*0.81*
Atlantic	*0.00*	*0.00*
Alaska	*0.03*	*0.00*
Total proved reserves	***4.13***	***15.36***
Inferred reserves		
Gulf of Mexico	*9.33*	*48.83*
Pacific	*0.89*	*0.26*
Atlantic	*0.00*	*0.00*
Alaska	*0.00*	*0.00*
Total inferred reserves	***10.21***	***49.09***
Total OCS resources	***93.31***	***456.11***

AEO2009. It is based on the *AEO2009* reference case but assumes that access to the Atlantic, Pacific, and Eastern/Central Gulf of Mexico OCS will be limited again by reinstatement of the moratoria as they existed before July 2008. In the OCS limited case, technically recoverable resources in the OCS total 75 billion barrels of oil and 380 trillion cubic feet of natural gas.

The projections in the OCS limited case indicate that reinstatement of the moratoria would decrease domestic production of both oil and natural gas and increase their prices (Table 9). The impact on domestic crude oil production starts just before 2020 and increases through 2030. Cumulatively, domestic crude oil production from 2010 to 2030 is 4.2 percent lower in the OCS limited case than in the reference case. In 2030, lower 48 offshore crude oil production in the OCS limited case (2.2 million barrels per day) is 20.6 percent lower than in the reference case (2.7 million barrels per day), and total domestic crude oil production, at 6.8 million barrels per day, is 7.4 percent lower than in the reference case (Figure 13).

Figure 13. U.S. total domestic oil production in two cases, 1990-2030 (million barrels per day)



In 2007, domestic crude oil production totaled 5.1 million barrels per day.

With limited access to the lower 48 OCS, U.S. dependence on imports increases, and there is a small increase in world oil prices. Oil import dependence in 2030 is 43.4 percent in the OCS limited case, as compared with 40.9 percent in the reference case, and the total annual cost of imported liquid fuels in 2030 is $403.4 billion, 7.1 percent higher than the projection of $376.6 billion in the reference case. The average price of imported low-sulfur crude oil in 2030 (in 2007 dollars) is $1.34 per barrel higher, and the average U.S. price of motor gasoline price is 3 cents per gallon higher, than in the reference case.

As with liquid fuels, the impact of limited access to the OCS on the domestic market for natural gas is seen mainly in the later years of the projection. Cumulative domestic production of dry natural gas from 2010 through 2030 is 1.3 percent lower in the OCS limited case than in the reference case. Because the volume of technically recoverable natural gas in the OCS areas previously under moratoria accounts for less than 5 percent of the total U.S. technically recoverable natural gas resource base, the impacts for natural gas volumes are smaller, relative to the baseline supply level, than those for oil volumes.

In 2030, dry natural gas production from the lower 48 offshore totals 4.1 trillion cubic feet in the OCS limited case, as compared with 4.9 trillion cubic feet in the reference case. The reduction in offshore supply of natural gas in the OCS limited case is partially offset, however, by an increase in onshore production. Reduced access in the OCS limited case results in higher natural gas prices, which increase the projection for U.S. onshore production in 2030 by 0.2 trillion cubic feet over the reference case projection. The

Table 9. Crude oil and natural gas production and prices in two cases, 2020 and 2030

Projection	Crude oil production (million barrels per day)	Crude oil price (2007 dollars per barrel)	Motor gasoline price (2007 dollars per gallon)	Natural gas production (trillion cubic feet)	Natural gas price (2007 dollars per thousand cubic feet)
2020					
Reference case	6.48	115.45	3.60	21.48	6.75
OCS limited case	6.21	115.56	3.60	21.27	6.83
Difference from reference case	-0.27	0.10	0.00	-0.21	0.08
Percent difference from reference case	-4.2	0.1	0.0	-0.7	1.2
2030					
Reference case	7.37	130.43	3.88	23.60	8.40
OCS limited case	6.83	131.76	3.91	23.00	8.61
Difference from reference case	-0.54	1.34	0.03	-0.60	0.21
Percent difference from reference case	-7.4	1.0	0.8	-2.6	2.5

average U.S. wellhead price of natural gas in 2030 (per thousand cubic feet, in 2007 dollars) is 21 cents higher in the OCS limited case, and net imports increase by 240 billion cubic feet. The higher average wellhead price for natural gas from the lower 48 States in the OCS limited case is associated with a decrease in consumption of 360 billion cubic feet in 2030 relative to the reference case. Total U.S. production of dry natural gas is 210 billion cubic feet less in 2020 and 600 billion cubic feet less in 2030 in the OCS limited case than projected in the reference case (Figure 14).

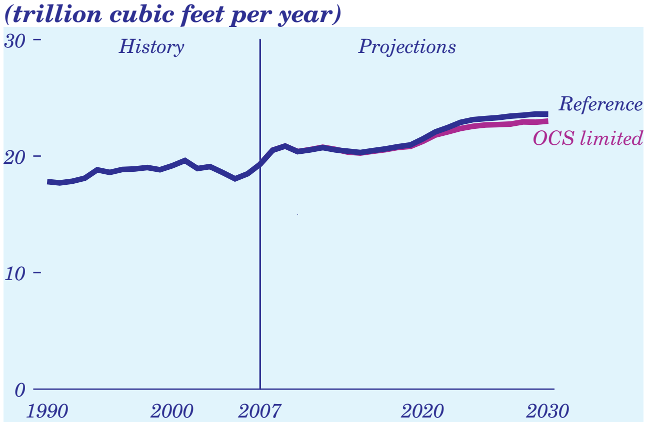
Offshore production, particularly in the OCS, has been an important source of domestic crude oil and natural gas supply, and it continues to be a key source of domestic supply throughout the projections either with or without the restoration of leasing moratoria as they existed before 2008.

Expectations for Oil Shale Production

Background

Oil shales are fine-grained sedimentary rocks that contain relatively large amounts of kerogen, which can be converted into liquid and gaseous hydrocarbons (petroleum liquids, natural gas liquids, and methane) by heating the rock, usually in the absence of oxygen, to 650 to 700 degrees Fahrenheit (*in situ* retorting) or 900 to 950 degrees Fahrenheit (surface retorting) [*60*]. ("Oil shale" is, strictly speaking, a misnomer in that the rock is not necessarily a shale and contains no crude oil.) The richest U.S. oil shale deposits are located in Northwest Colorado, Northeast Utah, and Southwest Wyoming (Table 10). Currently, those deposits are the focus of petroleum industry research and potential future production.

Figure 14. U.S. total domestic dry natural gas production in two cases, 1990-2030 (trillion cubic feet per year)



Among the three States, the richest oil shale deposits are on Federal lands in Northwest Colorado.

The Colorado deposits start about 1,000 feet under the surface and extend down for as much as another 2,000 feet. Within the oil shale column are rock formations that vary considerably in kerogen content and oil concentration. The entire column ultimately could produce more than 1 million barrels oil equivalent per acre over its productive life. To put that number in context, Canada's Alberta oil sands deposits are expected to produce about 100,000 barrels per acre.

The recoverable oil shale resource base is characterized by oil yield per ton of rock, based on the Fischer assay method [*61*]. Table 10 summarizes the approximate recoverable oil shale resource within the three States, based on the relative oil concentration in the oil shale rock. In addition to oil, the estimates include natural gas and natural gas liquids, which make up 15 to 40 percent of the total recoverable energy, depending upon the specific shale rock characteristics and the process used to extract the oil and natural gas. The three States contain about 800 billion barrels of recoverable oil in deposits with expected yields of more than 20 to 25 gallons oil equivalent per ton, which are more attractive economically than deposits with lower concentrations of oil. In comparison, on December 31, 2007, U.S. crude oil reserves were 21 billion barrels, or roughly 2.5 percent of the amount potentially recoverable from oil shale deposits in the three States [*62*].

Oil Shale Production Techniques

Liquids and gases can be produced from oil shale rock by either *in situ* or surface retorting. During the mid-1970s and early 1980s, the petroleum industry focused its efforts primarily on underground mining and surface retorting, which consumes large volumes of water, creates large waste piles of spent shale, and extracts only the richest portion of the oil shale

Table 10. Estimated recoverable resources from oil shale in Colorado, Utah, and Wyoming

Oil concentration (gallons oil equivalent per ton of rock)	Recoverable oil resource (billion barrels oil equivalent)
>10	1,500
>15	1,200
>20	850
>25	750
>30	420
>40	250

formation. There were also some experiments using a "modified *in situ* process," in which rock was mined from the base of the oil shale formation, explosive charges were set in the mined-out area (causing the roof to collapse and fragmenting the rock into smaller masses), and underground fires were set on the rubble to extract natural gas and petroleum liquids. The combustion proved difficult to control, however, and the process produced only low yields of petroleum liquids. Surface subsidence and aquifer contamination were additional issues.

The *in situ* processes now under development raise the temperature of shale formations by using electrical resistance or radio wave heating in wells that are separate from the production wells. Also being considered are "ice walls"—commonly used in construction—both to keep water out of the areas being heated and to keep the petroleum liquids that are produced from contaminating aquifers. The benefits of those methods include uniform heating of the formation; high yields of gas and liquid per ton of rock; production of high-quality liquids that commingle naphtha, distillates, and fuel oil and can be upgraded readily to marketable products; production yields of more than 1 million barrels per acre in some locations; no requirement for disposal and remediation of waste rock; reduced water requirements; scalability, so that additional production can be added readily to an existing project at production costs equal to or less than the cost of the original project; and lower overall production costs. Given these advantages, an *in situ* process is likely to be used if large-scale production of oil shale is initiated.

Although the technical feasibility of *in situ* retorting has been proved, considerable technological development and testing are needed before any commitment can be made to a large-scale commercial project. EIA estimates that the earliest date for initiating construction of a commercial project is 2017. Thus, with the leasing, planning, permitting, and construction of an *in situ* oil shale facility likely to require some 5 years, 2023 probably is the earliest initial date for first commercial production.

Economic Issues

Because no commercial *in situ* oil shale project has ever been built and operated, the cost of producing oil and natural gas with the technique is highly uncertain. Current estimates of future production costs range from at least $70 to more than $100 per barrel oil equivalent in 2007 dollars. Therefore, future oil shale production will depend on the rate of technological progress and on the levels and volatility of future oil prices.

Technology progress rates will determine how quickly the costs of *in situ* oil shale extraction can be brought down and how quickly natural gas and petroleum liquids can be produced from the process. The *in situ* retorting techniques currently available require the production zone to be heated for 18 to 24 months before full-scale production can begin.

In addition to price levels, the volatility of oil prices is particularly important for a high-cost, capital-intensive project like oil shale production, because price volatility increases the risk that costs will not be recovered over a reasonable period of time. For example, if oil prices are unusually low when production from an oil shale project begins, the project might never see a positive rate of return.

Public Policy Issues

Development of U.S. oil shale resources also faces a number of public policy issues, including access to Federal lands, regulation of CO_2 emissions, water usage and wastewater disposal, and the disturbance and remediation of surface lands. If the petroleum industry were not permitted access to Federal lands in the West, especially in Northwest Colorado, the industry would be excluded from the largest and most economical portion of the U.S. oil shale resource base.

In addition, current regulations of the U.S. Bureau of Land Management require that any mineral production activity on leased Federal lands also produce any secondary minerals found in the same deposit. On Federal oil shale lands, deposits of nahcolite (a naturally occurring form of sodium bicarbonate, or baking soda) are intermixed with the oil shales. Relative to oil and other petroleum products, nahcolite is a low-value commodity, and its price would fall even further if its production increased significantly. Thus, co-production of nahcolite could increase the cost of producing oil shale significantly, while providing little revenue in return.

Bringing Alaska North Slope Natural Gas to Market

At least three alternatives have been proposed over the years for bringing sizable volumes of natural gas from Alaska's remote North Slope to market in the lower 48 States: a pipeline interconnecting with the existing pipeline system in central Alberta, Canada;

a GTL plant on the North Slope; and a large LNG export facility at Valdez, Alaska. NEMS explicitly models the pipeline and GTL options [*63*]. The "what if" LNG option is not modeled in NEMS.

This comparison analyzes the economics of the three project options, based on the oil and natural gas price projections in the *AEO2009* reference, high oil price, and low oil price cases. The most important factors in the comparison include expected construction lead times, capital costs, and operating costs. Others include lower 48 natural gas prices, world crude oil and petroleum product prices, interest rates, and Federal and State regulation of leasing, royalty, and production tax rates. Each option also presents unique technological challenges.

Natural Gas Resources and Production Costs

Natural gas exists either in oil reservoirs as associated-dissolved (AD) natural gas or in gas-only reservoirs as nonassociated (NA) natural gas. Of the 35.4 trillion cubic feet of AD gas reserves discovered on the Central North Slope in conjunction with existing oil fields, 93 percent is located in four fields: Prudhoe Bay (23 trillion cubic feet), Point Thomson (8 trillion cubic feet), Lisburne (1 trillion cubic feet), and Kuparak (1 trillion cubic feet) [*64*]. Together, those resources are sufficient to provide 4 billion cubic feet of natural gas per day for a period of 24 years, at an expected average cost of $1.12 per thousand cubic feet (2007 dollars) [*65*]. The cost estimate is relatively low, because an extensive North Slope infrastructure has been built and paid for with revenues from oil production, and because there is considerably less exploration, development, and production risk associated with known deposits of AD natural gas.

Although additional AD natural gas might be discovered offshore or in the Arctic National Wildlife Refuge, most of the "second tier" discoveries in areas to the west and south of the Central North Slope are expected to consist of NA natural gas in gas-only reservoirs. Production costs for gas-only reservoirs are expected to be considerably higher than those for AD natural gas, because they are in remote locations. In addition, the full costs of their development will have to be paid for with revenues from the natural gas generated at the wellhead.

For the first tier of North Slope NA natural gas (29.2 trillion cubic feet) production costs are expected to average $7.91 per thousand cubic feet (2007 dollars). For the second tier, production costs are expected to average $11.03 per thousand cubic feet. Because the cost of producing NA natural gas is substantially greater than the cost of producing AD natural gas, this analysis uses the lower production costs for AD natural gas to evaluate the economic merits of the three facility options examined.

Facility Cost Assumptions

Of the three facility options, the costs associated with an Alaska gas pipeline are reasonably well defined, because they are based on the November 2007 pipeline proposals submitted to the State of Alaska by ConocoPhillips and TransCanada Pipelines, in compliance with the requirements of the Alaska Gasline Inducement Act. Costs associated with GTL and LNG facilities are more speculative, because they are based on the costs of similar facilities elsewhere in the world, adjusted for the remote Alaska location and for recent worldwide increases in construction costs (Table 11).

Key assumptions for all the options analyzed include natural gas feedstock requirements of 4 billion cubic feet per day, natural gas heating values, characteristics of the operations, and State and Federal income tax rates. The time required for planning, obtaining required permits, and facility construction is unique to each facility. Other key assumptions that are unique to each option include the following: for the Alaska pipeline option, the tariff rate for the existing pipeline from Alberta to Chicago and the spot price for natural gas in Chicago; for the LNG facility option, capital and operating costs, including the cost of building a pipeline from the North Slope to liquefaction and storage facilities in Valdez, and the value of LNG delivered in Asia and Valdez (which is contractually tied to oil prices); and for the GTL facility option, the time required to conduct tests to determine whether the Trans Alaska Pipeline System (TAPS) should be operated in batch or commingled mode with GTL, the production level and mix of product, the oil pipeline tariff and tanker rates to U.S.

Table 11. Assumptions for comparison of three Alaska North Slope natural gas facility options

Assumption	*Pipeline option*	*LNG option*	*GTL option*
Natural gas conversion efficiency (percent)	*94*	*80*	*60*
Capital costs (billion 2007 dollars)	*27.6*	*33.9*	*57.5*
Operating costs (million 2007dollars per year)	*263.0*	*392.9*	*894.3*

West Coast refiners, and the price of GTL products relative crude oil prices. The costs of testing and possibly converting TAPS into a batching crude/product pipeline are not included for the GTL option.

Discussion

To compare the economics of the three options, an internal rate of return (IRR) was calculated for each alternative, based on the projected average price of light, low-sulfur crude oil and the projected average price of natural gas on the Henry Hub spot market in the *AEO2009* reference, high oil price, and low oil price cases for the 2011-2020 and 2021-2030 periods (Table 12). The IRR calculations (Figures 15 and 16) assume that the average prices for the period in which a facility begins operation will persist throughout the 20-year economic life of the facility. Projected crude oil prices show considerably more variation across the cases and time periods than do Henry Hub natural gas prices, affecting the relative economics of the three options. In 2030, in the low and high oil price cases, crude oil prices are $50 and $200 per barrel, respectively, and lower 48 natural gas prices are $8.70 and $9.62 per million Btu, respectively (all prices in 2007 dollars).

The *AEO2009* projections show wide variations in oil prices, which are set outside the NEMS framework to reflect a range of potential future price paths. For natural gas prices, variations across the cases are smaller, reflecting the feedbacks in NEMS that equilibrate supply, demand, and prices in the natural gas market model. Natural gas price increases are held in check by declines in demand (especially in the electric power sector) and increases in natural gas drilling, reserves, and production capacity. Conversely, natural gas price declines are held in check by increases in demand and decreases in drilling, reserves, and production capacity. Natural gas prices are also restrained because only a small portion of the natural gas resource base is consumed through 2030, and the marginal cost of natural gas supply increases slowly.

IRRs for the pipeline option respond to natural gas price levels, whereas IRRs for the GTL and LNG options respond to crude oil prices (Figures 15 and 16). From 2021 through 2030, IRRs for the pipeline option vary by 15 to 17 percent across the three price cases, whereas those for the GTL and LNG options vary by 4 to 24 percent and 7 to 27 percent, respectively. On that basis, the pipeline option would be considerably less risky than either the GTL or LNG option. Also, the pipeline would involve significantly less engineering, construction, and operation risk than either of the other options.

The potential viability of an Alaska natural gas pipeline is bolstered by the fact that BP, ConocoPhillips, and TransCanada Pipelines already have committed to building a pipeline. All three have extensive

Table 12. Average crude oil and natural gas prices in three cases, 2011-2020 and 2021-2030

	2011-2020	*2021-2030*
Oil price (2007 dollars per barrel)		
Reference	*107.32*	*123.26*
High oil price	*154.24*	*193.25*
Low oil price	*51.61*	*50.31*
Natural gas price (2007 dollars per million Btu)		
Reference	*7.04*	*8.21*
High oil price	*7.52*	*8.50*
Low oil price	*6.24*	*7.88*

Figure 15. Average internal rates of return for three Alaska North Slope natural gas facility options in three cases, 2011-2020 (percent)

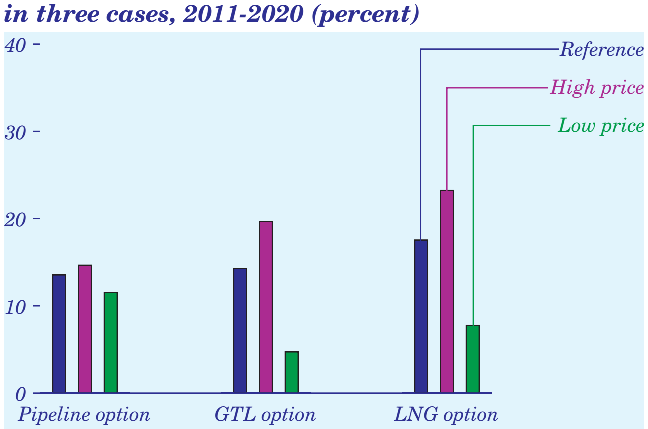
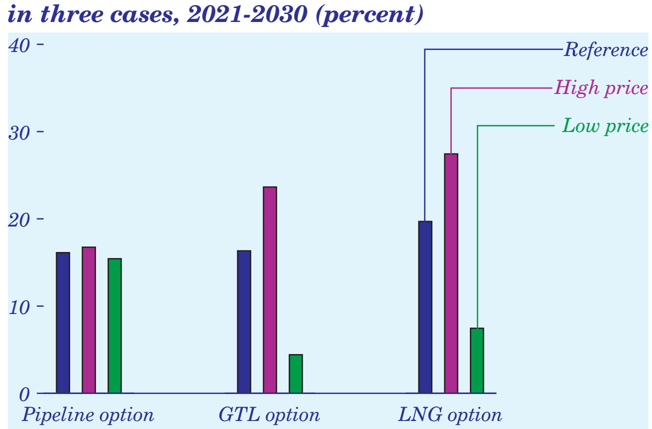


Figure 16. Average internal rates of return for three Alaska North Slope natural gas facility options in three cases, 2021-2030 (percent)



experience in building and financing large-scale energy projects, and both BP and ConocoPhillips have access to substantial portions of the less expensive North Slope AD natural gas reserves. Given that institutional support, along with the prospect for adequate rates of return, the natural gas pipeline option appears to have the greatest likelihood of being built.

Because the GTL option does not include the cost of testing and adapting the existing TAPS oil pipeline to GTL products—which would require third-party cooperation and likely cost reimbursement—the GTL rates of return are overstated. In addition, the GTL results include considerable uncertainty with regard to capital and operating costs and future environmental constraints on GTL plants. Prospects for Alaska GTL facilities are further clouded by the current absence of project sponsors.

Of the three options, an LNG export facility shows the highest rates of return in the reference and high price cases; however, it shows low rates of return in the low price case. The project risk associated with the LNG option is considerably less than that for the GTL option but greater than for the pipeline option. The LNG option is further undermined by the fact that there are large reserves of stranded natural gas elsewhere in the world that have a significant competitive advantage both because of their proximity to large consumer markets and because they would not require construction of an 800-mile supply pipeline through difficult terrain. Although there is definite interest in the LNG export option in Alaska, current advocates of the project have not yet secured letters of intent from potential buyers to purchase the LNG, nor do they have ownership of low-cost AD reserves, extensive experience in the management of large-scale projects, or strong financial backing. Finally, if shale deposits in the rest of the world turn out to be as rich in natural gas as those in the United States, worldwide demand for LNG could be reduced considerably from the levels that were expected just a few years ago.

Other Issues

The analysis described here focused primarily on the relative economics and risks associated with each of three options for a facility to bring natural gas from Alaska's North Slope to market. There are, in addition, a number of other issues that could be important in determining which facility option could proceed to construction and operation, four of which are described briefly below.

Resolving ownership issues for the Point Thomson natural gas condensate field lease. The State of Alaska has revoked the Point Thomson lease from the original leaseholders. Point Thomson holds approximately 8 trillion cubic feet of recoverable natural gas reserves, and without that supply, the existing North Slope AD reserves would be insufficient to supply a natural gas pipeline over a 20-year lifetime. The 35.4 trillion cubic feet of existing AD natural gas reserves on the Central North Slope includes Point Thomson's 8 trillion cubic feet, and without those reserves only 27.4 trillion cubic feet of North Slope gas reserves would be available, providing just 18.8 years of supply for a facility with a capacity of 4 billion cubic feet per day. As long as the ownership issue of the Point Thomson lease remains unresolved, the possibility of pursuing construction of any of the three options is diminished.

Obtaining permits for an Alaska natural gas pipeline in Canada. The pipeline option could encounter significant permitting issues in Canada, similar to those that have already been encountered by the Mackenzie Delta natural gas pipeline, whose construction has been significantly delayed as the result of a failure to secure necessary permits. Because there have been no filings for Canadian permits by any Alaska natural gas pipeline sponsor, the severity of this potential problem cannot be determined.

Exporting Alaska LNG to foreign consumers. Some parties in the United States have called for a halt to current exports of LNG from Alaska to overseas markets. If Alaska were prohibited from exporting LNG to overseas consumers, the financial risk associated with any new Alaska LNG facility would increase significantly, because the financial viability of an LNG facility would be tied solely to lower 48 natural gas prices, which are considerably lower than overseas natural gas prices.

Shipping GTL products through TAPS. The joint ownership structure of TAPS could prevent a minority owner from using the pipeline to ship GTL from the North Slope south to Valdez and on to market.

Conclusion

The *AEO2009* price cases project greater variance in oil prices than in natural gas prices. If those cases provide a reasonable reflection of potential future outcomes, then the pipeline option in this analysis would be exposed to less financial risk than the GTL and LNG options. Additionally, it is the only option that already has the commitment of energy companies capable of financing and constructing such a large, capital-intensive energy facility. The balance of the factors evaluated here points to an Alaska natural gas pipeline as being the most likely choice for bringing North Slope natural gas to market.

Natural Gas and Crude Oil Prices in *AEO2009*

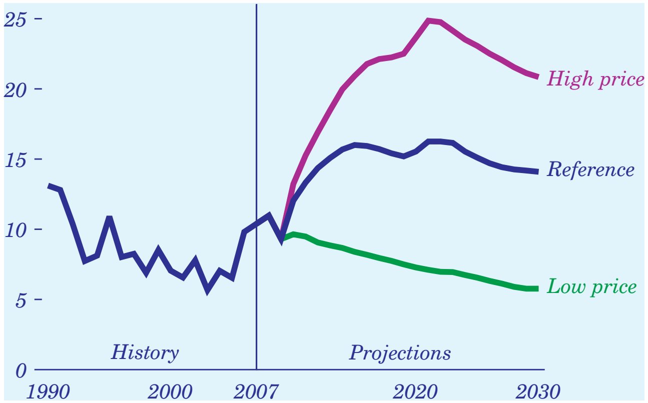
If oil and natural gas were perfect substitutes in all markets where they are used, market forces would be expected to drive their delivered prices to near equality on an energy-equivalent basis. The price of West Texas Intermediate (WTI) crude oil generally is denominated in terms of barrels, where 1 barrel has an energy content of approximately 5.8 million Btu. The price of natural gas (at the Henry Hub), in contrast, generally is denominated in million Btu. Thus, if the market prices of the two fuels were equal on the basis of their energy contents, the ratio of the crude oil price (the spot price for WTI, or low-sulfur light, crude oil) to the natural gas price (the Henry Hub spot price) would be approximately 6.0. From 1990 through 2007, however, the ratio of natural gas prices to crude oil prices averaged 8.6; and in the *AEO2009* projections from 2008 through 2030, it averages 7.7 in the low oil price case, 14.6 in the reference case, and 20.2 in the high oil price case (Figure 17).

The key question, particularly in the reference and high oil price cases, is why market forces are not expected to bring the ratios more in line with recent history. A number of factors can influence the ratio of oil prices to natural gas prices, as discussed below.

Crude Oil and Natural Gas Supply Markets

The methods and costs of transporting petroleum and natural gas are significantly different. The crude oil supply market is an international market, whereas the U.S. natural gas market is confined primarily to North America. In 2007, 43 percent of the oil and petroleum products consumed in the United States came by tanker from overseas sources [*66*]. In contrast, only 3 percent of total U.S. natural gas consumption came from overseas sources, by LNG tanker. Moreover, the domestic resource bases for the two fuels are significantly different. It is expected that lower 48 onshore natural gas resources will play a dominant role in meeting future domestic demand for natural gas, whereas imports of crude oil and petroleum products will continue to account for a significant portion of U.S. petroleum consumption.

Figure 17. Ratio of crude oil price to natural gas price in three cases, 1990-2030



Approximately 180 billion barrels of crude oil reserves and undiscovered resources are estimated to remain in the United States, equal to about 24 years of domestic consumption at 2007 levels; however, with more than 70 percent of those resources located offshore or in the Arctic, they will be relatively expensive to develop and produce [*67*]. The remaining U.S. natural gas resource base is much more abundant, estimated at 1,588 trillion cubic feet or nearly 70 years of domestic consumption at 2007 levels [*68*]. In addition, more than 70 percent of remaining U.S. natural gas resources are located onshore in the lower 48 States, which significantly reduces the cost of new domestic natural gas production.

The large domestic natural gas resource base has been estimated in one study to be sufficient to keep the long-run marginal cost of new domestic natural gas production between $5 and $8 (2007 dollars) per thousand cubic feet through 2030; however, the costs used in that study represent a period when drilling was unusually expensive, because oil and natural gas prices were high. In the future, cost for natural gas development and production could decline significantly as the demand for well drilling equipment and personnel comes into equilibrium with the available supply for those services [*69*].

In the *AEO2009* reference case, which projects a relatively low long-run marginal cost of natural gas, domestic production increasingly satisfies U.S. natural gas consumption. In 2030 more than 97 percent of the natural gas consumed in the United States is produced domestically, yet only 31 percent of the currently estimated U.S. natural gas resource base is produced by 2030. LNG imports remain a relatively small portion of U.S. natural gas supply, with their share peaking in 2018 at 6.5 percent and then falling to 3.5 percent in 2030.

The current opportunities for competition between oil and natural gas are relatively small in the United States (that is, the two U.S. supply markets are weakly linked). Although the relatively low costs projected for production of natural gas make it economically attractive in U.S. consumption markets where it competes with oil, particularly in the reference and high oil price cases, they are not low enough to make the United States a competitive source of natural gas for the world LNG market.

Also, large-scale conversion of lower 48 natural gas into liquid fuels is expected to be precluded by the inability of project sponsors to secure long-term natural gas supply contracts at guaranteed prices and volumes. Natural gas producers are unlikely to be able or willing to guarantee long-term volumes and prices.

Substitution of Natural Gas for Petroleum Consumption

In a relatively high oil price environment, as in the *AEO2009* reference and high oil price cases, consumers can reduce oil consumption through energy conservation and by switching to other forms of energy, such as natural gas, coal, renewables, and electricity. Natural gas is not necessarily the least expensive or quickest option to implement (in comparison with reducing transportation vehicle-miles traveled, for example).

In the residential, commercial, and electric power sectors, petroleum consumption is relatively small, accounting for only 6.5 percent of total U.S. petroleum consumption in 2007. Gradually converting all the petroleum consumption in those sectors to other fuels would have only a modest impact on natural gas consumption and prices.

In the industrial sector, the most feasible opportunity for substituting natural gas for petroleum is in heat and power uses, which amount to about 0.61 quadrillion Btu per year [*70*]; however, most petroleum consumption in the industrial sector (such as diesel and gasoline consumption by off-road vehicles in agricultural and construction activities; petroleum coke; refinery still gas, which is both produced and consumed in refineries; and road asphalt) is not well suited for conversion to natural gas. Also, there is considerable uncertainty about the extent to which petroleum feedstocks for chemical manufacturing could be replaced with natural gas before 2030. At a minimum, considerable downstream investment in chemical manufacturing processes would be required in order to convert to natural gas feedstock.

The greatest potential for large-scale substitution of natural gas for petroleum is in the transportation sector—especially, in local fleet vehicles refueled at a central facility, such as local buses, which consumed 0.18 quadrillion Btu in 2006 [*71*]. Wider use of natural gas as a fuel for transportation fleets also has been advocated; however, the idea faces significant hurdles given the relatively low energy density of natural gas; the cost, size, and weight of onboard storage systems; and the challenge of establishing a refueling infrastructure. In addition, any significant increase in natural gas use could raise natural gas prices sufficiently to reduce the ratio of natural gas prices to oil prices.

The Honda Civic GX and Civic LX-S vehicles provide a uniform basis for comparing the attributes of a natural-gas-fueled LDV (the GX) and a gasoline-fueled LDV (the LX-S) that use the same design platform (Table 13). The Honda GX is about 34 percent more expensive, carries 39 percent less fuel (resulting in a much shorter refueling range of about 200 to 220 miles), and provides 50 percent less cargo space, 19 percent less horsepower, and 15 percent less torque. Although natural gas has a high octane rating of 130, the GX horsepower and torque are reduced by the rate at which natural gas can be injected into the piston cylinders because of its lower energy density.

Although the higher cost and other disadvantages of natural gas vehicles could be offset at least partially

Table 13. Comparison of gasoline and natural gas passenger vehicle attributes

Attribute	Gasoline-fueled 2009 Honda Civic LX-S	Natural-gas-fueled 2009 Honda Civic GX	Percent difference
Sticker price (2007 dollars)	18,855	25,190	34
Curb weight (pounds)	2,754	2,910	6
Fuel tank capacity (gallons)	13.2	8.0	-39
Passenger space (cubic feet)	90.9	90.9	—
Cargo space (cubic feet)	12.0	6.0	-50
Horsepower at 6,300 rpm	140	113	-19
Torque at 4,300 rpm	128	109	-15

by their lower fuel costs, the lack of an extensive natural gas refueling infrastructure will remain a difficult hurdle to overcome. Consumers are unlikely to purchase natural gas vehicles if there is considerable uncertainty as to whether they can be refueled when and where they need to be. Similarly, service station owners are unlikely to install natural gas refueling equipment if the number of natural gas vehicles on the road is insufficient to pay for the infrastructure costs.

In 2008, there were only 778 service stations in the United States with natural gas refueling capability out of a total of more than 120,000 service stations [*72*]. Public refueling capability for natural gas, ethanol, methanol, and electric vehicles has fluctuated considerably over time, as the different vehicle options have gained and lost favor with the public. Even after the more than 15 years that these alternative fuel options have existed, fewer than 1 percent of the Nation's public service stations currently offer refueling capability for any alternative fuel.

Without an extensive public refueling network, the potential for market penetration by natural gas vehicles will be limited, and until a substantial number have been purchased, an extensive public refueling network is unlikely to develop. Market penetration by natural gas vehicles is also limited by the many alternatives that consumers have for reducing vehicle petroleum consumption, including buying smaller vehicles, reducing vehicle-miles traveled, and buying hybrid electric or, potentially, all-electric vehicles. In addition, price volatility in crude oil and natural gas markets obscures the long-term financial viability of natural gas vehicles. Consequently, *AEO2009* assumes that widespread adoption of natural gas vehicles in the United States is unlikely under current laws and policies.

Conclusion

Through 2030, an abundance of low-cost, onshore lower 48 natural gas resources, in conjunction with a limited set of opportunities to substitute natural gas for petroleum, is projected to raise the ratio of oil prices to natural gas prices above the historical range, as reflected in *AEO2009* reference and high oil price cases. Unless there is large-scale growth in the use of natural gas in the transportation sector, it is unlikely that fuel substitution in the other end-use sectors will be sufficient to reduce the price ratio significantly before 2030.

Electricity Plant Cost Uncertainties

Construction costs for new power plants have increased at an extraordinary rate over the past several years. One study, published in mid-2008, reported that construction costs had more than doubled since 2000, with most of the increase occurring since 2005 [*73*]. Construction costs have increased for plants of all types, including coal, nuclear, natural gas, and wind.

The cost increases can be attributed to several factors, including high worldwide demand for generating equipment, rising labor costs, and, most importantly, sharp increases in the costs of materials (commodities) used for construction, such as cement, iron, steel, and copper. Commodity prices continued to rise through most of 2008, but as oil prices dropped precipitously in the last quarter of the year, commodity prices began to decline. The most recent power plant capital cost index published by Cambridge Energy Research Associates (CERA) shows a slight decline in the index over the past 6 months, and CERA analysts expect further declines [*74*].

The current financial situation in the United States will also affect the costs of future power plant construction. Financing large projects will be more difficult, and as the slowing economy leads to lower demand for electricity, the need for new capacity may be limited. The resultant easing of demand for construction materials and equipment could lead to lower costs for materials and equipment when new investment does take place in the future. Fluctuating commodity prices, combined with the uncertain financial environment, increase the challenge of projecting future capital costs.

Because some plant types—coal, nuclear, and most renewables—are much more capital-intensive than others (such as natural gas), the mix of future capacity builds and fuels used can differ, depending on the future path of construction costs. If construction costs increase proportionately for all plant types, natural-gas-fired capacity will become more economical than more capital-intensive technologies. Over the longer term, higher construction costs are likely to lead to higher energy prices and lower energy consumption.

The *AEO2009* version of NEMS includes updated assumptions about the costs of new power plant construction. It also assumes that power plant costs will be influenced by the real producer price index for metals and metal products, leading to a decline in base construction costs in the later years of the projections. As sensitivities to the *AEO2009* reference case, several alternative cases assuming different trends in capital costs for power plant construction were used to examine the implications of different cost paths for new power plant construction.

Power Plant Capital Cost Cases

For the *AEO2009* reference case, initial capital costs for new generating plants were updated on the basis of costs reported in late 2007 and early 2008. The reference case cost assumptions reflect an increase of roughly 30 percent relative to the cost assumptions used in *AEO2008*, and they are roughly 50 percent higher than those used in earlier *AEO*s. Because there is a strong correlation between rising power plant construction costs and rising commodity prices, construction costs in *AEO2009* are tied to a producer price index for metals and metal products. The nominal index is converted to a real annual cost factor, using 2009 as the base year. The resulting reference case cost factor remains nearly flat for the next few years, then declines by a total of roughly 15 percent to the end of the projection in 2030. As a result, future capital costs are lower even before technology learning adjustments are applied. The same cost factor is applied to all technology types.

Although the correlation between construction costs and the producer price index for metals has been high in recent years, it is possible that costs could be affected by other factors in the future. There is also uncertainty in the metals index forecast, as with any projection. Therefore, the sensitivity cases do not use the metals index to adjust plant costs but instead use exogenous assumptions about future cost adjustment factors to provide a range of cost assumptions.

In the frozen plant capital costs case, base overnight construction costs for all new electricity generating technologies are assumed to remain constant at 2013 levels (which is when the cost factor peaks in the reference case). Because cost decreases still can occur as a result of technology learning, costs do decline slightly from 2013 to 2030 in the frozen costs case. In 2030, costs for all technologies are roughly 20 percent higher than in the reference case.

In the high plant capital costs case, base overnight construction costs for all new generating plants are assumed to continue increasing throughout the projection, by assuming that the cost factor increases by 25 percentage points from 2013 to 2030. Again, cost decreases still can occur as a result of technology, partially offsetting the increases. For most technologies, however, costs in 2030 are above current costs. Plant construction costs in 2030 in the high plant capital costs case are about 50 percent higher than in the reference case.

In the falling plant capital costs case, base overnight construction costs for all generating technologies fall more rapidly than in the reference case, starting in 2013. In 2030, the cost factor is assumed to be 25 percentage points below the reference case value.

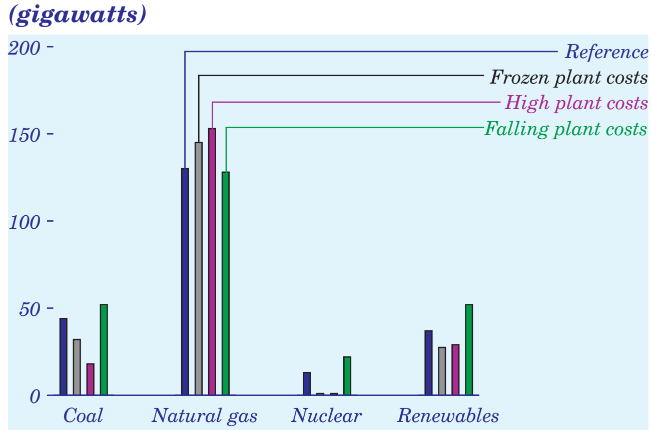
Results

Capacity Additions

Overall capacity requirements, as well as the mix of generating types, change across the alternative plant cost cases. In the reference case, 259 gigawatts of new generating capacity is added from 2007 to 2030. In the frozen and high plant costs cases, capacity additions fall to 247 gigawatts and 237 gigawatts, respectively. In the falling plant costs case, additions increase to 288 gigawatts.

In all the plant costs cases, the vast majority of new capacity is fueled by natural gas, in part because coal, nuclear, and renewable technologies are more capital-intensive; however, the fuel shares of total builds do differ among the cases (Figure 18). Coal-fired plants make up 18 percent of all the new capacity built in the reference case through 2030. Across the alternative cases, their share ranges from 9 percent to 20 percent. In the frozen plant costs and high plant costs cases, no nuclear capacity is built beyond the 1.2 gigawatts of planned additions. In the falling plant

Figure 18. Cumulative additions to U.S. electricity generation capacity by fuel in four cases, 2008-2030 (gigawatts)



costs case, more than 20 gigawatts of nuclear capacity is built. Renewable capacity makes up a 22-percent share of all new capacity built in the reference case; the renewable share remains between 21 and 22 percent in the high plant costs and frozen plant costs cases and increases to 25 percent in the falling plant costs case.

Electricity Generation and Prices

Differences among the projections for generation fuel mix in the different cases are not as large as the differences in the projections for capacity additions, because the construction cost assumptions do not affect the operation of existing capacity. Coal maintains the largest share of total generation through 2030, ranging from 44 percent to 47 percent in 2030 across the four cases (Figure 19). The renewable share in 2030 is nearly the same in all the cases, from 14 percent to 15 percent, because all the cases assume that the same State and regional RPS goals must be met. In the frozen and high plant costs cases, biomass co-firing is used predominantly to meet RPS requirements, rather than investment in new renewable capacity. In the falling plant costs case, generation from biomass co-firing is less than projected in the reference case, and wind generation provides more of the renewable requirement.

Nuclear generation provides 18 percent of total generation in 2030 in the reference case, compared with 16 percent in the frozen and high plant costs cases and 19 percent in the falling plant costs case. Natural-gas-fired generation, typically the source of marginal electricity supply, follows an opposite path, increasing by 22 percent from the reference case projection in 2030 in the high plant costs case and by 14 percent in the frozen plant costs case, and decreasing by 11 percent in the falling plant costs case. As a result, delivered natural gas prices vary among the different cases, increasing by as much as 10 percent from the reference case projection in the high plant costs case and decreasing by 6 percent in the falling plant costs case. Electricity prices in 2030, following the trend in natural gas prices, are 5 percent higher than the reference case projection in the high plant costs case (where electricity prices also rise in response to higher construction costs) and 5 percent lower than the reference case projection in the falling plant costs case (Figure 20).

Tax Credits and Renewable Generation

Background

Tax incentives have been an important factor in the growth of renewable generation over the past decade, and they could continue to be important in the future. The Energy Tax Act of 1978 (Public Law 95-618) established ITCs for wind, and EPACT92 established the Renewable Electricity Production Credit (more commonly called the PTC) as an incentive to promote certain kinds of renewable generation beyond wind on the basis of production levels. Specifically, the PTC provided an inflation-adjusted tax credit of 1.5 cents per kilowatthour for generation sold from qualifying facilities during the first 10 years of operation. The credit was available initially to wind plants and facilities that used "closed-loop" biomass fuels [*75*] and were placed in service after passage of the Act and before June 1999.

The 1992 PTC has lapsed periodically, but it has been renewed before or shortly after each expiration date, typically for an additional 1- or 2-year period. In addition, eligibility has been extended to generation from many different renewable resources [*76*], including

Figure 19. Electricity generation by fuel in four cases, 2007 and 2030 (billion kilowatthours)

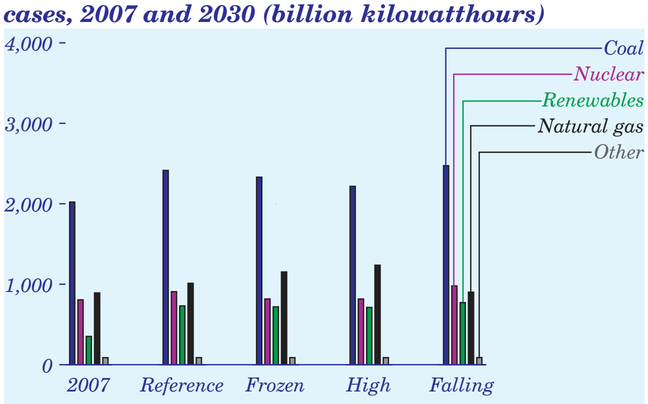
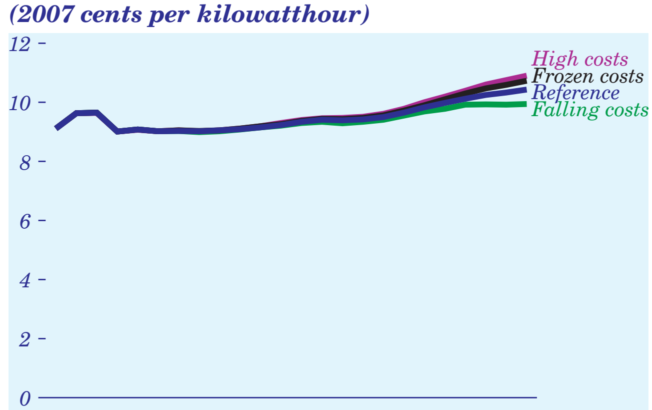


Figure 20. Electricity prices in four cases, 2007-2030 (2007 cents per kilowatthour)

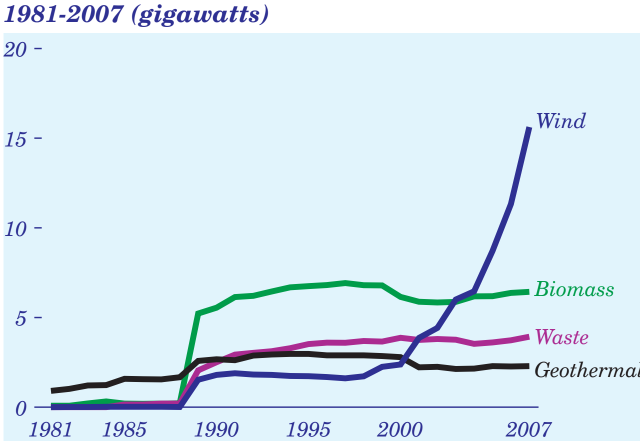


poultry litter, geothermal energy [77], certain hydroelectric facilities [78], "open-loop" biomass [79], landfill gas, and, most recently, marine energy resources. Open-loop biomass and landfill gas currently receive one-half the PTC value (1 cent rather than the current inflation-adjusted 2 cents available to other eligible resources). Eligibility of new projects for the PTC was set to expire at the end of 2008, but it was extended to December 31, 2009, for wind capacity and to December 31, 2010, for other eligible renewable facilities [80].

As this publication was being prepared, the PTC was further extended and modified by ARRA2009, which extends eligibility for the PTC to December 31, 2012, for wind projects and to December 31, 2013, for all other eligible renewable resources. In addition, project owners may elect to receive a 30-percent ITC in lieu of the PTC, and may further elect to receive an equivalent grant in lieu of the ITC. Project owners electing the grant must commence their projects during 2009 or 2010. These recently passed provisions are not included in *AEO2009*.

The PTC has contributed significantly to the expansion of the wind industry over the past 10 years. Since 1998, wind capacity has grown by an average of more than 25 percent per year (Figure 21). Although some of the more recent growth may be attributable to State programs, especially the mandatory RPS programs now in effect in 28 States and the District of Columbia, the importance of the PTC is evidenced by the growth of wind power installations in States without renewable mandates, either today or at the time the installations were constructed, and by the significant drop in new wind installations during periods when the PTC has been allowed to lapse.

Figure 21. Installed renewable generation capacity, 1981-2007 (gigawatts)



Although other renewable generation facilities, such as geothermal or poultry litter plants, have been able to claim the PTC, none has grown as dramatically as wind power. Possible explanations for their slower rate of expansion include longer construction lead times and less favorable economics for some facilities. In addition, some provisions of the PTC may limit its ability to be used fully or efficiently for some projects. For example, project owners that do not pay Federal income taxes (such as municipal utilities and rural electric cooperatives) cannot claim the PTC, even though they may be eligible for other Federal assistance. Also, the owners of for-profit projects must have sufficient tax liability to claim the full PTC, and their eligibility for PTC payments may be limited by the Federal alternative minimum tax law.

The wind industry, in particular, has developed several alternative ownership and finance structures to help minimize the impact of the limitations [81]. There is some evidence, however, that the restrictions reduce the value of the PTC to project owners. In addition, the financial crisis of 2008 may exacerbate the problems for some projects [82]. As part of ARRA2009, developers may, for a limited time, convert the PTC into a 30-percent ITC and then into a grant. This provision may lessen the impact of the financial crisis on the ability of wind developers to use the PTC. As noted above, the provisions of ARRA2009 are not included in *AEO2009*.

Future Impacts

Because *AEO2009* represents only those laws and policies in effect on or before November 4, 2008, the renewable energy PTC is assumed to expire at the end of 2009 for wind and at the end of 2010 for other eligible renewables; however, the program has a long history of renewal and extension, and there is considerable interest, both in Congress and in the renewable energy industry, in keeping the credit available over the longer term, as seen in the recent extension to 2013.

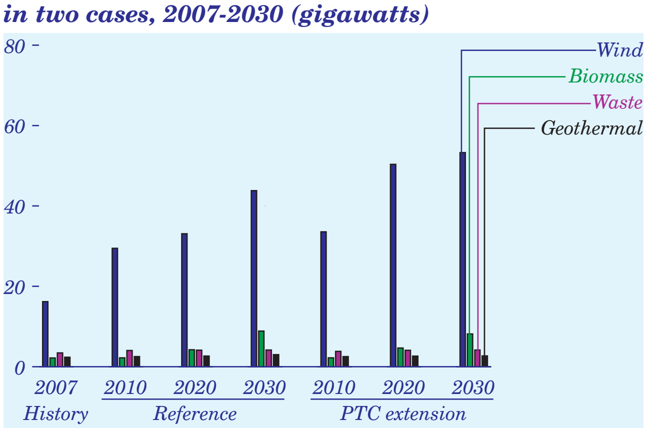
To examine the potential impacts of a PTC extension, *AEO2009* includes a production tax credit extension case that examines the potential impacts of extending the current credit through 2019. Because EIA does not develop or advocate policy, the PTC extension case is included here only to assess the potential impacts of such an extension and should not be construed as a proposal for, or endorsement of, any legislative action.

Aside from the expiration date, no changes in current PTC provisions are assumed in the PTC extension case. The credit is valued at 2 cents per kilowatthour (in 2008 dollars, adjusted for projected inflation rates) for wind, geothermal, and hydroelectric generation and at 1 cent per kilowatthour for biomass and landfill gas [*83*]. It is assumed that all eligible facilities will receive the credit for the first 10 years of plant operation, and that they will use the credit efficiently and completely, without further modification of the law. The extension is assumed to be continuous over the 10-year period and not subject to the periodic cycle of expiration and renewal that has affected the PTC in the past.

For wind power installations, a 10-year extension of the PTC results in significantly more capacity growth than in the reference case (Figure 22). In the near term, capacity increases would be comparable to those seen over the past several years, followed by a period of several years in which the capacity expansion is slower, corresponding to a projected lull in electricity demand growth. Significant additional growth in wind capacity occurs thereafter, before the assumed 2019 expiration date, with total capacity increasing to approximately 50 gigawatts in 2020, as compared with 33 gigawatts in the reference case. Additional capacity expansion occurs after 2020 in both cases, particularly in the reference case, where 11 gigawatts of installed capacity is added from 2020 to 2030 as compared with 2 gigawatts in the PTC extension case.

For eligible technologies other than wind, no significant changes in capacity installations are projected in the PTC extension case relative to the reference case. In part, this may be a result of the shorter lead times

Figure 22. Installed renewable generation capacity in two cases, 2007-2030 (gigawatts)



associated with wind technology: wind plants can be built before the projected slowdown in electricity demand growth after 2010, potentially "crowding out" other PTC-eligible investments. In addition, the economics for wind installations are fundamentally more favorable than for other PTC-eligible resources, and the resource base for wind power is more widespread.

Because eligible renewable generation still accounts for a relatively small share of total U.S. electricity generation, the PTC extension case has relatively minor impacts outside the markets for renewable generation. A 10-year extension of the PTC reduces average electricity prices in 2020 by approximately 1 percent relative to the reference case. The extension costs the Federal Government approximately $7.7 billion from 2010 to 2019 (in 2007 dollars) [*84*], while cumulative savings on electricity expenditures from 2010 to 2019 total about $13 billion in comparison with the reference case.

Total electricity generation in 2020 in the PTC extension case is less than 0.5 percent greater than in the reference case. The increase in wind-powered electricity generation in the PTC extension case primarily offsets the use of natural gas in the power sector, reducing natural-gas-fired generation by about 5 percent in 2020 compared to the reference case. Impacts on other generation fuels generally are less than 1 percent. The maximum reduction in CO_2 emissions from the electric power sector (occurring before 2020) is about 0.5 percent compared to the reference case.

Greenhouse Gas Concerns and Power Sector Planning

Background

Concerns about potential climate change driven by rising atmospheric concentrations of GHGs have grown over the past two decades, both domestically and abroad. In the United States, potential policies to limit or reduce GHG emissions are in various stages of development at the State, regional, and Federal levels. In addition to ongoing uncertainty with respect to future growth in energy demand and the costs of fuel, labor, and new plant construction, U.S. electric power companies must consider the effects of potential policy changes to limit or reduce GHG emissions that would significantly alter their planning and operating decisions. The possibility of such changes may already be affecting planning decisions for new generating capacity.

California and 10 States in the Northeast are moving forward with mandatory emissions reduction programs. For 10 Northeastern States, 2009 is the inaugural year of the RGGI, a cap-and-trade program for power plant emissions of CO_2 [*85*]. RGGI sets a cap of 188 million metric tons CO_2 in 2009 for power generating facilities with rated capacity greater than 25 megawatts and lowers that cap annually to 169 million metric tons in 2018. Although RGGI represents the first legally binding regulation of CO_2 emissions in the United States and will influence future decisions about investments in generating capacity, its overall impact is expected to be modest. In 2006, CO_2 emissions from power plants covered by RGGI accounted for only 7 percent of the CO_2 emitted from all U.S. power plants, and their total 2006 emissions—at 164 million metric tons—already were below the 2018 goal of 169 million metric tons.

Other regional initiatives also are being developed. The WCI consists of seven Western U.S. States and four Canadian Provinces [*86*]. A draft rule released in July 2008 aims at an economy-wide cap on six GHGs, including CO_2. The cap level and details of the program design still are being developed. In November 2007, the governors of 10 Midwestern States signed the Midwestern Greenhouse Gas Reduction Accord [*87*], currently in the preliminary stages of development, with the broad goal of creating a multi-sector, interstate cap-and-trade program for the member States.

At the State level, 37 individual States have released State-specific climate change mitigation plans; however, the only legally binding requirements outside the RGGI States are in California, which has passed Assembly Bill (A.B.) 32, the Global Warming Solutions Act of 2006 [*88*]. A.B. 32 aims to reduce the State's GHG emissions to 1990 levels by 2020. Although specific regulations associated with A.B. 32 remain to be finalized, the law requires that policies be designed to meet the reduction targets.

At the national level, numerous bills to reduce GHGs have been introduced in the U.S. Congress in recent years. As of July 2008, a total of 235 bills, amendments, and resolutions addressing climate change in some form had been introduced in the 110th Congress. Nine of the bills—three in the House and six in the Senate—specifically proposed a cap-and-trade system for CO_2 and other GHGs. Of the nine, the Boxer-Lieberman-Warner Climate Security Act (S. 3036) progressed the farthest, reaching the floor of the Senate in June 2008 [*89*].

Even without the enactment of national emissions limits, many State utility regulators and the banks that finance new power plants are requiring assessments of GHG emissions for new projects. For example, many State public utility commissions now are requiring that utilities review projected CO_2 emissions in their integrated resource plans (IRPs) [*90*]. The IRP process is intended to keep public utility regulators at the State level informed of their utilities' strategies to meet future demand and supply. The treatment of projected CO_2 emissions has differed among utilities. Some have included an emissions price in their base case scenarios; others have done so in alternative scenarios. Typically, the emissions prices used have ranged from \$5 to \$80 per metric ton.

Several major banks in the United States also have decided to include future CO_2 emissions as a factor in their decisionmaking processes for financing of new power plants. In February 2008, Citibank, JPMorgan Chase, and Morgan Stanley announced the formation of "The Carbon Principles," which provide climate change guidelines for advisors and lenders to power companies in the United States [*91*]. Adopters of the principles would commit to:

- Encourage clients to pursue cost-effective energy efficiency, renewable energy, and other low-carbon alternatives to conventional generation, taking into consideration the potential value of avoided CO_2 emissions
- Ascertain and evaluate the financial and operational risk to fossil fuel generation financings posed by the prospect of domestic CO_2 emissions controls through the application of an "Enhanced Diligence Process," and use the results of this diligence as a contribution to the determination whether a transaction is eligible for financing and under what terms
- Educate clients, regulators, and other industry participants regarding the additional diligence required for fossil fuel generation financings, and encourage regulatory and legislative changes consistent with the principles.

Reflecting Concerns Over Greenhouse Gas Emissions in AEO2009

Key questions in the development of the *AEO2009* projections included the degree to which ongoing debate about potential climate change policies, together with the actions taken by State regulators and the financial community, already are affecting planning and operating decisions in the electric power sector, and how best to capture those impacts in the analysis. Although existing plants continue to be operated on a least-cost basis without adjustments for GHG emissions levels, concerns about GHG emissions do appear to be having an impact on decisions about new plants.

When regulators and banks are reviewing the projected GHG emissions of new plants in their investment evaluation process, they are implicitly adding a cost to some plants, particularly those that involve GHG-intensive technologies. The implicit cost could be represented by adding an amount to the operating costs of plants that emit CO_2 to reflect the value of emissions; however, doing so would affect not only planning decisions for new capacity but also future utilization decisions for all plants—something that does not appear to be occurring on a widespread basis in markets today.

Alternatively, the costs of building and financing new GHG-intensive capacity could be adjusted to reflect the implicit costs being added by utilities, their regulators, and the financial community. This option better reflects current market behavior, which is focused on discouraging power companies from investing in high-emission technologies. As a result, in the *AEO2009* reference case, a 3-percentage-point increase is added to the cost of capital for investments in GHG-intensive technologies, such as coal-fired power plants without CCS and CTL plants.

Although the 3-percentage-point adjustment is somewhat arbitrary, its impact in levelized cost terms is similar to that of a $15 fee per metric ton of CO_2 for investments in new coal-fired power plants without CCS—well within the range of the results of simulations that utilities and regulators have prepared. The adjustment should be seen not as an increase in the actual cost of financing but rather as representing the implicit costs being added to GHG-intensive projects to account for the possibility that, eventually, they may have to purchase allowances or invest in other projects that offset their emissions.

Two alternative cases were prepared to show how the representation of investment behavior in the electric power sector affects the *AEO2009* reference case projections, given uncertainty about the evolution of potential GHG policies. In the no GHG concern case, the cost-of-capital adjustment for GHG-intensive technologies is removed to represent a future in which concern about GHG emissions wanes or efforts to implement GHG reduction regulations subside. This case reflects an approach similar to that used for the reference case in past *AEO*s. In the LW110 case, the GHG emissions reduction policy called for in S. 2191, the Lieberman-Warner Climate Security Act of 2007 introduced in the 110th Congress, is analyzed [*92*]. This case illustrates a future in which an explicit Federal policy limiting GHG emissions is enacted, affecting both planning and operating decisions.

Because the projected impact of any policy to reduce GHG emissions will depend on its detailed specifications—which may differ significantly from those in the LW110 case—results from the LW110 case do not apply to other past or future policy proposals. Rather, projections in the two alternative cases illustrate the potential importance to the electric power industry of GHG policy changes, and why uncertainty about such changes weighs heavily on planning and investment decisions.

Findings

The imposition of a GHG reduction policy would affect all aspects of the electric power industry, including decisions about the types of plants built to meet growing electricity demand, the fuels used to generate electricity, the prices consumers will pay in the future, and GHG emissions from electric power plants.

Capacity

Generating capacity investment decisions in the two sensitivity cases differ from those in the *AEO2009* reference case (Figure 23). The overall amounts of new capacity added in the reference case and the no GHG concern case are similar, but there are differences in the mix of plant types built. New coal builds without CCS are higher in the no GHG concern case than in the reference case, as the concern that new regulations might be coming dampens investment in new coal-fired plants in the reference case. On the other hand, new natural-gas-fired plants, which are not as GHG-intensive, are more attractive economically in the reference case. In an environment of uncertainty about future regulation of CO_2 emissions, natural gas becomes the primary choice for new capacity additions; without such uncertainty, coal remains the primary choice. Concern about possible new regulations plays a role in the construction of a modest amount of nuclear power and renewable energy capacity in the reference case, but other incentives also influence their selection. It is unclear whether utilities would be willing to incur the high costs of building new nuclear plants in the absence of concerns about potential GHG regulations.

The cap-and-trade policy adopted in the LW110 case changes the mix of capacity additions significantly relative to the other cases. The adjusted cost of capital in the reference case increases the cost of building new GHG-intensive facilities but does not change the cost of operating those plants already in service or new plants once they are built. The introduction of an explicit cap on GHG emissions adds a cost to the emissions generated from existing and new facilities, making carbon-intensive coal-fired plants more expensive to build and operate. As a result, approximately 35 percent of the existing fleet of coal-fired plants is retired by 2030 in the LW110 case, and 33 percent more new capacity is added than in the reference case, replacing the retired capacity. The explicit GHG emission constraint results in the construction of a different mix of new capacity additions, with new nuclear power, renewables, and coal with CCS making up a majority of the capacity added. The new capacity additions lead to a significantly different portfolio of generation assets and generation by fuel in 2030.

The results show that implementation of the LW110 case would lead to greater use of coal with CCS, nuclear, and renewable capacity; however, there is significant uncertainty around the projections. New coal-fired plants with CCS equipment have not been fully commercialized, and it is unclear when they might be and what they would cost. Similarly, a rapid expansion of nuclear capacity also would present challenges, including uncertainty both about the cost of the plants and about public acceptance of them. There also may be limits to a rapid expansion of renewable generation, because many of the best resources are located far from electricity load centers. Previous EIA analysis has found that, if the expansion is limited, the electricity industry may rely more heavily on new natural-gas-fired plants to reduce GHG emissions, leading to higher allowance costs and higher electricity prices [*93*].

Generation by Fuel

Among the three cases examined, total electricity generation in 2030 is lowest in the LW110 case (Figure 24 and Table 14). The explicit cap raises the price of electricity, which over time slows the growth in demand for electricity, lowering generation requirements. The opposite is true in the no GHG concern case, where lower electricity prices stimulate higher demand for electricity and increase generation requirements. Generation from coal drops the most in the LW110 case. Relative to the *AEO2009* reference case, the explicit GHG emission cap reduces the total amount of electricity generated from all coal-fired plants by 33 percent and the amount from coal-fired plants without CCS by 68 percent in 2030, as older coal plants are retired and the marginal costs of units still operating, which must hold allowances, are higher. Despite their high initial capital costs, new coal-fired units with CCS are less expensive to operate than traditional coal-fired plants without CCS, given a tight constraint on CO_2 emissions. The shares of renewables and nuclear power in the generation mix also increase significantly in the LW110 case, as low-emissions technologies are added to meet the growing demand for electricity.

Electricity Prices

Projected electricity prices are lowest in the no GHG concern case, where there is no cap on emissions, and coal-fired plants with relatively low fuel costs

Figure 23. Cumulative additions to U.S. generating capacity in three cases, 2008-2030 (gigawatts)

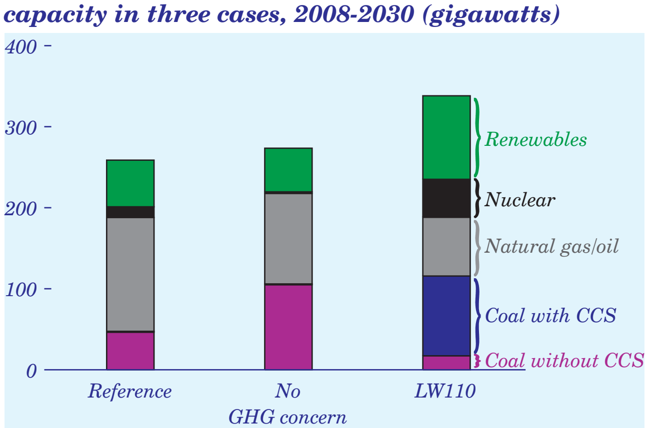
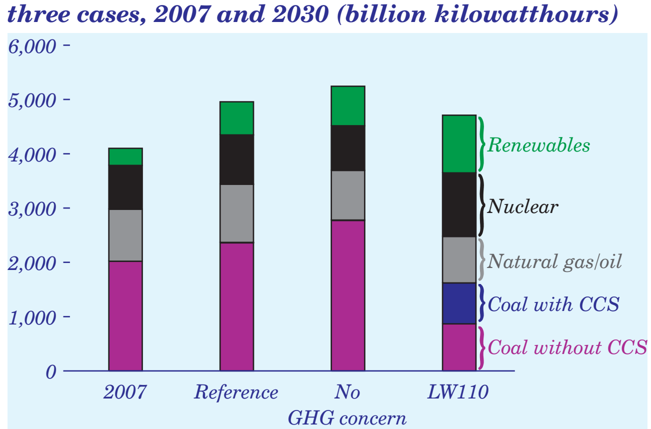


Figure 24. U.S. electricity generation by source in three cases, 2007 and 2030 (billion kilowatthours)



continue to dominate the mix of generation (Figure 25). Greater reliance on natural gas in the reference case leads to higher electricity prices when construction of carbon-intensive facilities, including coal-fired plants, is dampened because of uncertainty about possible GHG regulations.

An explicit cap on GHG emissions adds an additional cost to the generation of electricity from CO_2-emitting sources. To lower emissions in the LW110 case, the industry turns to more expensive resources and allowance purchases to cover remaining emissions. Therefore, electricity generated from fossil fuels becomes more expensive, while higher priced low-emitting sources, such as nuclear, renewables, and coal with CCS, become more cost-competitive. As a result, the cost of generating electricity increases. In 2030, the price of electricity is 22 percent higher in the LW110 case than in the reference case and 26 percent higher than in the no GHG concern case.

Emissions

The electric power sector is expected to play a major role in any effort to reduce GHG emissions in the United States (Figure 26). The sector accounted for 41 percent of energy-related CO_2 emissions in 2007, and its emissions are projected to grow. On the other hand, a wide array of fuels and technologies with

Table 14. Summary projections for alternative GHG cases, 2020 and 2030

		2020			2030		
State	*2007*	*Reference*	*No GHG concern*	*LW110*	*Reference*	*No GHG concern*	*LW110*
Delivered energy prices (2007 dollars per unit)							
Motor gasoline (per gallon)	2.80	3.60	3.59	3.85	3.88	3.79	4.37
Jet fuel (per gallon)	2.17	2.99	2.97	3.30	3.32	3.24	3.95
Diesel (per gallon)	2.74	3.47	3.44	3.78	3.83	3.72	4.45
Natural gas (per thousand cubic feet)							
Residential	13.05	12.85	12.64	14.84	14.71	14.29	18.97
Electric power	7.22	7.35	7.15	9.01	8.94	8.47	12.51
Coal, electric power sector (per million Btu)	1.78	1.92	1.94	5.25	2.04	2.16	8.72
Electricity (cents per kilowatthour)	9.11	9.41	9.33	10.23	10.43	10.08	12.70
Energy consumption (quadrillion Btu)							
Liquids	40.75	38.93	38.97	38.35	41.60	41.66	39.87
Natural gas	23.70	24.09	23.78	22.88	25.04	24.02	22.45
Coal	22.74	23.98	24.80	20.30	26.56	30.62	16.40
Nuclear power	8.41	8.99	8.77	9.36	9.47	8.58	12.21
Renewable/other	6.05	9.26	9.28	11.15	10.67	10.71	15.24
Electricity imports	0.11	0.06	0.06	0.10	0.10	0.04	0.31
Total	**101.77**	**105.31**	**105.65**	**102.16**	**113.43**	**115.62**	**106.46**
Electricity generation (billion kilowatthours)							
Petroleum	66	58	58	55	60	61	53
Natural gas	892	898	852	828	1,012	854	803
Coal	2,021	2,156	2,235	1,846	2,415	2,779	1,621
Nuclear power	806	862	840	897	907	822	1,170
Renewable	352	617	619	789	730	728	1,063
Other (includes pumped storage)	22	28	28	27	28	27	27
Total	**4,159**	**4,618**	**4,632**	**4,442**	**5,153**	**5,272**	**4,737**
Carbon dioxide emissions (million metric tons)							
Electric power sector, by fuel							
Petroleum	66	40	40	37	41	42	36
Natural gas	376	357	340	325	378	321	260
Coal	1,980	2,089	2,142	1,685	2,299	2,494	868
Other	12	12	12	12	12	12	13
Total	**2,433**	**2,497**	**2,534**	**2,059**	**2,729**	**2,869**	**1,176**
Total carbon dioxide emissions, all sectors	**5,991**	**5,982**	**6,044**	**5,436**	**6,414**	**6,745**	**4,615**

various emission levels are used in the electric power sector, providing some flexibility for altering emissions levels without turning to wholly unknown technologies or requiring end-use consumers to purchase any new equipment. Increases in CO_2 emissions from

the electric power sector are projected to continue through 2030 in the no GHG concern case and the *AEO2009* reference case. In the no GHG concern case, emissions are expected to rise as demand for electricity increases and coal's share of the national generation mix grows to 53 percent in 2030. Emissions also continue to increase through 2030 in the reference case but at a slower rate because of the reduced reliance on coal for generation.

In the LW110 case, in contrast, CO_2 emissions from the electric power sector are projected to fall significantly over time. In this case, CO_2 emissions from the electric power sector in 2030 are projected to be 52 percent below their 2007 level and 57 percent below the level in the reference case.

Figure 25. U.S. electricity prices in three cases, 2005-2030 (2007 cents per kilowatthour)

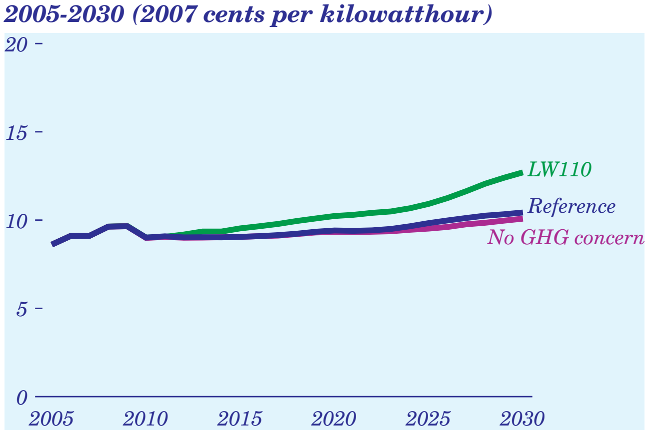
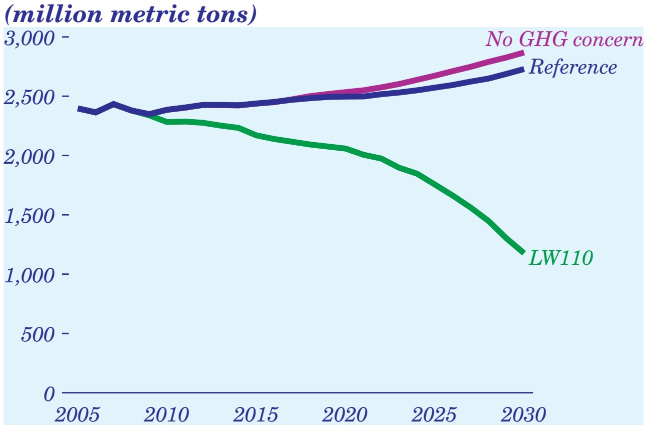


Figure 26. Carbon dioxide emissions from the U.S. electric power sector in three cases, 2005-2030 (million metric tons)



Endnotes for Issues in Focus

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56. The Alaska OCS has not been subject to leasing restrictions since 2007. In the North Aleutian Basin of Alaska, the Congressional moratorium was lifted in 2004, and the Presidential withdrawal was lifted in 2007.
57. See Legislation and Regulations, "Regulations Related to the Outer Continental Shelf Moratoria and Implications of Not Renewing the Moratoria."
58. The ban on areas in the Eastern and Central Gulf of Mexico through 2022 imposed by the Gulf of Mexico Energy Security Act of 2006 remains in place. *AEO2009* assumes no restrictions on drilling in the Atlantic and Pacific OCS through 2030.
59. U.S. Department of the Interior, Minerals Management Service, *Draft Proposed Outer Continental Shelf (OCS) Oil and Gas Leasing Program 2010-2015* (Washington, DC, January 2009), web site www.mms.gov/5%2Dyear/2010-2015New5-YearHome.htm.

60. This discussion is based largely on data from U.S. Department of Energy, Office of Naval Petroleum and Oil Shale Reserves, *Strategic Significance of America's Oil Shale Resource, Volume II, Oil Shale Resources, Technology and Economics* (Washington, DC, March 2004), web site www.fossil.energy.gov/ programs/reserves/npr/publications/npr_strategic_significancev2.pdf.
61. The Fischer assay is a standardized laboratory test for determining oil and natural gas yields from oil shale rock.
62. Energy Information Administration, *Advance Summary, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 2007 Annual Report*, DOE/EIA-0216(2007) Advance Summary (Washington, DC, October 2008), Table 1, p. 5, web site www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/advanced_summary/current/adsum.pdf.
63. The GTL option is represented in NEMS in the form of facilities with capacities of 34,000 barrel per day that can be added incrementally when oil and petroleum product prices are sufficiently high to make their operation profitable.
64. Alaska Department of Natural Resources, Division of Oil and Gas, *Alaska Oil and Gas Report 2007* (Anchorage, AK, July 2007), Table III.1, p. 3-2, web site www.dog.dnr.state.ak.us/oil/products/publications/annual/report.htm.
65. K.W. Sherwood and J.D. Craig, *Prospects for Development of Alaska Natural Gas: A Review as of January 2001* (Anchorage, AK: U.S. Department of Interior, Minerals Management Service, Resource Evaluation Office), Chapters 4 and 5, web site www.mms.gov/alaska/re/natgas/akngas2.pdf. Resource recovery costs were updated for this analysis, to reflect the escalation of drilling costs over time.
66. All 2007 oil and natural gas supply and consumption figures are taken from Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384 (2007) (Washington, DC, June 2008), web site www.eia.doe.gov/emeu/aer/contents.html.
67. Crude oil and natural gas resource figures are those represented in NEMS, which are based on the most current U.S. Geological Survey and U.S. Minerals Management Service undiscovered resource estimates. They include proven crude oil and natural gas reserves as of January 1, 2007.
68. When the entire natural gas resource base in Alaska is included in the U.S. natural gas resource estimate, the total represents more than 75 years of domestic supply at 2007 consumption rates.
69. INGAA Foundation, *Availability, Economics and Production Potential of North American Unconventional Natural Gas Supplies*, F-2008-3, Table 32 (Washington, DC, November 2008).
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73. Cambridge Energy Research Associates, "Construction Costs for New Power Plants Continue to Escalate: IHS CERA Power Capital Costs Index" (press release, May 27, 2008), web site www.cera.com/aspx/cda/public1/news/pressReleases/pressReleaseDetails.aspx?CID=9505.
74. Cambridge Energy Research Associates, "IHS CERA Power Capital Costs Index Shows Power Plant Construction Costs Decreasing Slightly" (press release, December 17, 2008), web site http://press.ihs.com/article_display.cfm?article_id=3953.
75. Closed-loop biomass is defined as any organic material from a plant that is cultivated exclusively for use in producing electricity at a qualifying facility.
76. Solar installations received the credit for a brief period, from 2004 to 2005. Certain types of coal facilities can claim a tax credit under Section 45 of the U.S. Internal Revenue Code, and some qualifying nuclear plants may also claim a production tax credit.
77. Geothermal energy is also eligible for a 10-percent Federal ITC, but a facility cannot claim both credits.
78. Eligibility is limited to "incremental" generation resulting from capital investments at existing hydroelectric facilities.
79. Open-loop biomass includes waste and residue materials from certain agricultural, forestry, and urban or industrial processes.
80. Marine resources must be in service by December 31, 2011, to be eligible for the PTC.
81. See, for example, J.P. Harper, M.D. Karcher, and M. Bolinger, *Wind Project Financing Structures: A Review & Comparative Analysis*, LBNL-63434 (Berkeley, CA: Lawrence Berkeley National Laboratory, September 2007), web site http://eetd.lbl.gov/EA/EMP/reports/63434.pdf.
82. C. Carlson and G.E. Metcalf, "Energy Tax Incentives and the Alternative Minimum Tax," *National Tax Journal*, Vol. 61, No. 3 (September 2008), web site www.entrepreneur.com/tradejournals/article/190149936.html.

83. Because the projection does not show any use of closed-loop resources, the open-loop credit value is assumed. EIA currently does not model marine energy technologies.
84. Using a real discount rate of 7 percent. PTC costs for 2009, estimated at $3.6 billion, are not included.
85. The participating States are New York, New Jersey, Connecticut, Massachusetts, Maine, New Hampshire, Vermont, Rhode Island, Delaware, and Maryland. See Regional Greenhouse Gas Initiative, web site www.rggi.org/states.
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92. The LW110 case is based on S. 2191, which is the most recent GHG bill analyzed by EIA as of November 2008. The choice is not meant to imply that EIA supports or does not support S. 2191 or any other particular past or future proposal.
93. Energy Information Administration, *Energy and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007*, SR/OIAF/2008-01 (Washington, DC, April 2008), web site www.eia.doe.gov/oiaf/servicerpt/s2191/index.html.

Market Trends

The projections in *AEO2009* are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The projections are business-as-usual trend estimates, reflecting known technology and technological and demographic trends. *AEO2009* generally assumes that current laws and regulations are maintained throughout the projections. Thus, the projections provide a policy-neutral reference case that can be used to analyze policy initiatives. EIA does not propose or advocate future legislative or regulatory changes.

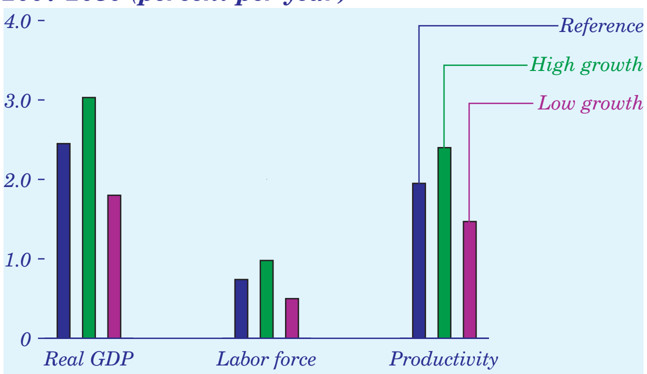
Because energy markets are complex, models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets cannot be anticipated, including severe weather, political disruptions, strikes, and technological breakthroughs. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty. Many key uncertainties in the *AEO2009* projections are addressed through alternative cases.

EIA has endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not a substitute for, a complete and focused analysis of public policy initiatives.

AEO2009 Presents Three Views of Economic Growth

Figure 27. Average annual growth rates of real GDP, labor force, and productivity in three cases, 2007-2030 (percent per year)



AEO2009 presents three views of economic growth (Figure 27). The rate of growth in real gross domestic product (GDP) depends mainly on assumptions about labor force growth and productivity. In the reference case, growth in real GDP averages 2.5 percent per year from 2007 to 2030.

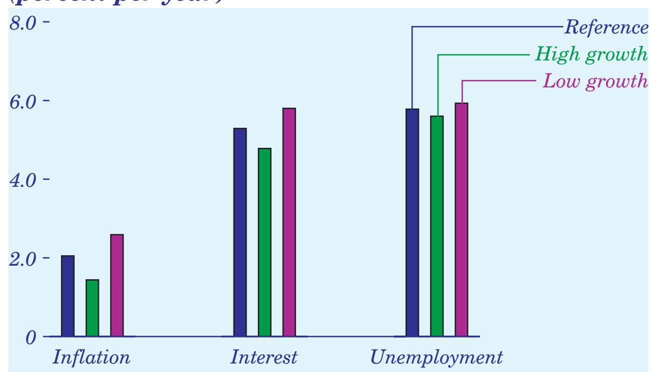
GDP growth is considerably slower in the near term as a result of the recent downturn in financial markets. In the *AEO2009* reference case, annual real GDP growth is negative in 2009 and does not start to recover until the fourth quarter of 2009.

The *AEO2009* high and low economic growth cases examine the impacts of alternative assumptions about the U.S. economy (see Appendix E for descriptions of all the alternative cases). The high economic growth case includes more rapid growth in the labor force, nonfarm employment, and productivity, resulting in real GDP growth of 3.0 percent per year. With higher productivity gains and employment growth, inflation and interest rates are lower than in the reference case.

In the low economic growth case, real GDP growth averages 1.8 percent per year from 2007 to 2030 as a result of slower growth in the labor force, nonfarm employment, and labor productivity. Consequently, the low growth case shows higher inflation, higher interest rates, and lower growth rates for industrial output and employment.

Inflation, Interest, and Jobless Rates Vary With Increases in Productivity

Figure 28. Average annual inflation, interest, and unemployment rates in three cases, 2007-2030 (percent per year)



In the *AEO2009* reference case, the average annual consumer price inflation rate is 2.1 percent, the annual yield on the 10-year Treasury note averages 5.3 percent, and the average unemployment rate is 5.8 percent (Figure 28). The higher inflation, interest, and unemployment rates in the low economic growth case and the lower rates in the high economic growth case depend on differences in assumptions about labor productivity and population growth.

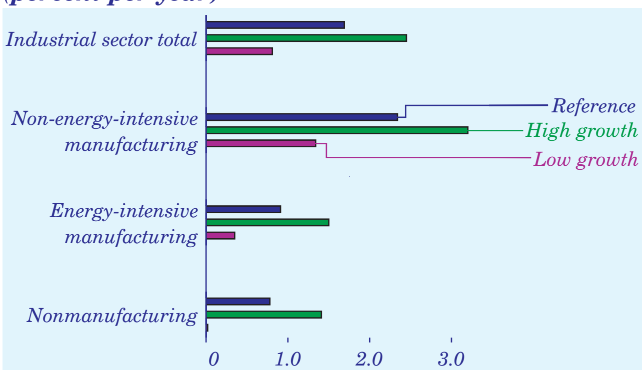
Over the first 5 years of the *AEO2009* reference case, inflation and interest rates are low, and unemployment rates rise as a result of the recession that began at the end of 2007. With the downturn affecting household wealth and economic output, unemployment remains high as people need more time to find employment. The unemployment rate does not fall back to its long-run average of 5.8 percent until 2015.

From 1982 to 2007, inflation averaged 3.1 percent per year, the average yield on 10-year Treasury notes was 7.1 percent per year, and the unemployment rate averaged 6.0 percent per year. In the *AEO2009* reference case, continuing gains in labor productivity and lower labor costs relative to historical averages lead to more optimistic projections for inflation, interest, and unemployment rates.

For U.S. consumers, energy prices in the reference case rise more rapidly than overall prices. For energy commodities, annual price increases average 3.0 percent per year from 2007 to 2030, and for energy services they average 2.3 percent per year.

Output Growth for Energy-Intensive Industries Is Expected To Slow

Figure 29. Sectoral composition of industrial output growth rates in three cases, 2007-2030 (percent per year)



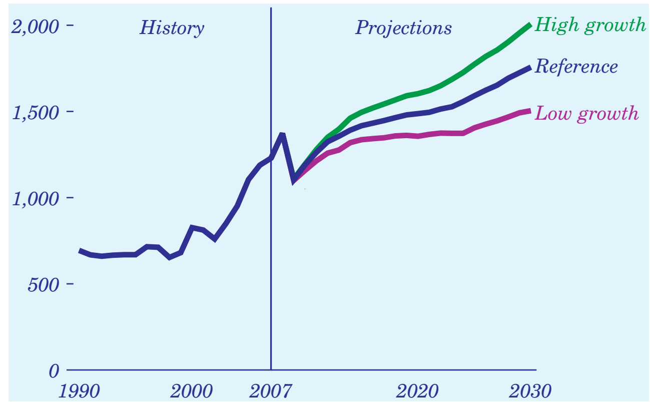
Industrial sector output has grown more slowly than the total economy in recent decades, as imports have met a growing share of demand for industrial goods. In the *AEO2009* reference case, real GDP grows at an annual average rate of 2.5 percent from 2007 to 2030, whereas the industrial sector grows by a slower 1.7 percent per year (Figure 29). Manufacturing output of goods grows more rapidly than nonmanufacturing output (which includes agriculture, mining, and construction). With higher energy prices and more foreign competition, the energy-intensive manufacturing sectors [*94*] grow at a slower overall rate of 0.9 percent per year, which includes a 0.4-percent annual decline for bulk chemicals and a 1.8-percent annual increase for food processing.

The construction, chemicals, primary metals, and transportation equipment industries grow slowly in the early years of the projection as the economy recovers from the current economic recession. After 2011, however, their output returns to its long-run growth path. Increased foreign competition, weak expansion of domestic production capacity, and higher energy prices mean more competitive pressure for most energy-intensive industries, particularly after 2015.

In the high economic growth case, output from the industrial sector grows by an annual average of 2.4 percent, still below the annual growth of real GDP (3.0 percent). In the low economic growth case, real GDP and industrial output grow by 1.8 and 0.8 percent per year, respectively. In both cases, the non-energy-intensive manufacturing industries show higher growth than the rest of the industrial sector.

Energy Expenditures Decline Relative to Gross Domestic Product

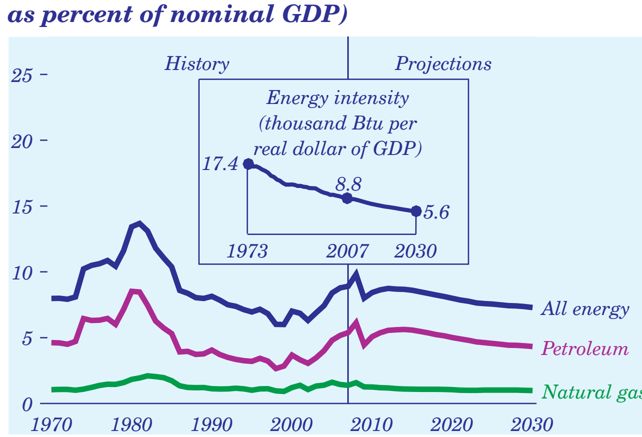
Figure 30. Energy expenditures in the U.S. economy in three cases, 1990-2030 (billion 2007 dollars)



Total expenditures for energy services in the U.S. economy were $1.2 trillion in 2007. Energy expenditures rise to $1.8 trillion (2007 dollars) in 2030 in the *AEO2009* reference case, $2.0 trillion in the high economic growth case, and $1.5 trillion in the low economic growth case (Figure 30). Energy intensity, measured as energy consumption (thousand Btu) per dollar of real GDP, was 8.8 in 2007 (Figure 31). With structural shifts in the economy, improvements in energy efficiency, and rising world oil prices, energy intensity declines to a ratio of 5.6 in 2030.

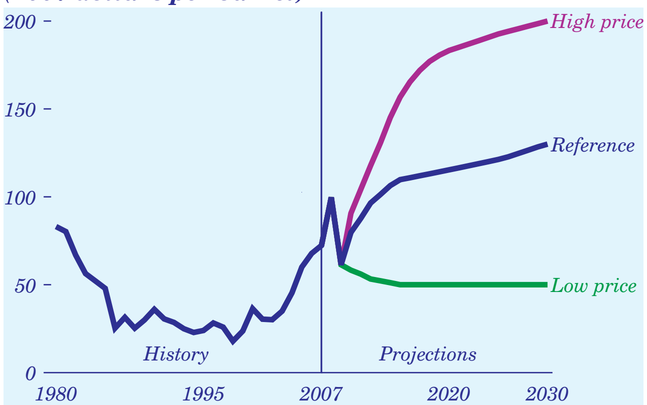
Since 2003, rising oil prices have pushed the nominal share of energy expenditures as a percent of GDP upward, and their 9.8-percent share in 2008 was the highest since 1986. In the reference case, as the energy efficiency of the economy improves, their share declines to 7.3 percent of GDP in 2030.

Figure 31. Energy expenditures as a share of gross domestic product, 1970-2030 (nominal expenditures as percent of nominal GDP)



Oil Price Cases Show Uncertainty in Prospects for World Oil Markets

Figure 32. World oil prices in three cases, 1980-2030 (2007 dollars per barrel)



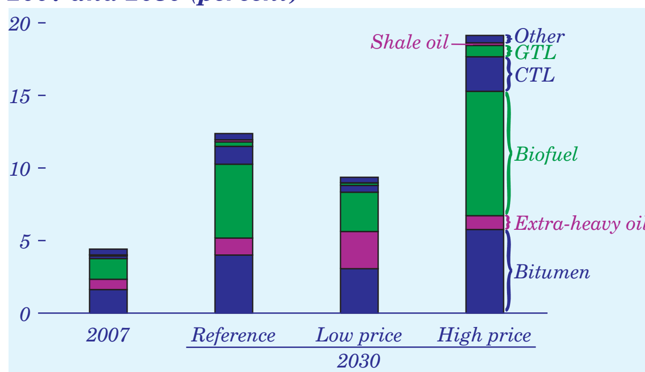
World oil price projections in *AEO2009*, defined in terms of the average price of imported low-sulfur, light crude oil to U.S. refiners, span a broad range that reflects the inherent uncertainty of world oil prices (Figure 32). The *AEO2009* low and high oil price paths are not intended to provide lower and upper bounds for future oil prices but rather to allow the analysis of possible future world oil market conditions that differ significantly from those assumed in the reference case. The long-term oil price paths are based on access to and cost of non-OPEC oil, OPEC supply decisions, and the supply potential of unconventional liquids, as well as the demand for liquids.

The high price case depicts a future world oil market in which conventional production is restricted by political decisions as well as by resource availability, as major producing countries use quotas, fiscal regimes, and various degrees of nationalization to increase their national revenues from oil production, and consuming countries turn to high-cost production of unconventional liquids to satisfy demand.

The low price case depicts a market in which non-OPEC producing countries develop stable fiscal policies and investment regulations directed at encouraging private-sector participation in the development of their resources. Although OPEC nations are not expected to change current investment restrictions significantly, the organization is expected to increase production in order to achieve an approximate 50-percent share of total world liquids production (119 million barrels per day) in 2030.

Unconventional Resources Gain Market Share as Prices Rise

Figure 33. Unconventional production as a share of total world liquids production in three cases, 2007 and 2030 (percent)



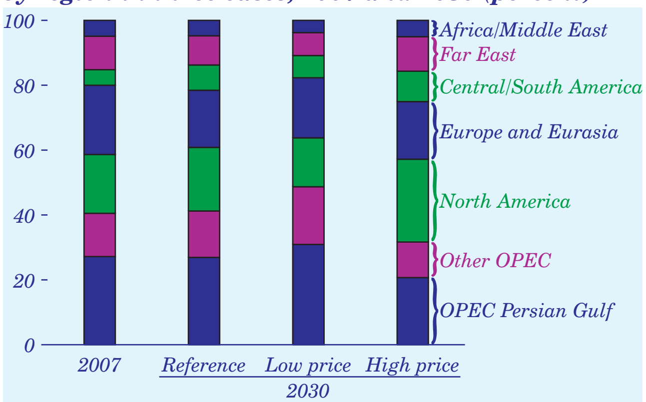
World production of liquid fuels from unconventional resources in 2007 was 3.6 million barrels per day, or about 4 percent of total liquids production. In the low oil price, reference, and high oil price cases, production from unconventional sources grows to between 11 million barrels per day and 17 million barrels per day, accounting for 9 percent to 19 percent of total liquids production, respectively, in 2030 (Figure 33).

Bitumen production from Canadian oil sands—by far the largest source of future unconventional liquids supply from any country—varies by about 1.5 million barrels per day across the three cases. The fiscal regime, extraction technologies, and relative profitability of projects associated with the Canadian bitumen are relatively constant, regardless of world oil prices. Production from Venezuela's extra-heavy oil resource depends on the market environment, not because of the oil price path but as a result of the levels of economic access to resources in the different cases. In the low price case, with more foreign investment, production in 2030 is more than double that in the reference case. In the reference and high price cases, with growing nationalization trends, production is limited to about 1 million barrels per day in 2030.

Production of biofuels, CTL, and GTL will be dictated largely by the needs of consuming nations—particularly, the United States and China, to compensate for restrictions on economic access to conventional liquid resources. In 2030, total production from those three sources ranges from 4.0 million barrels per day in the low price case to 10.4 million barrels per day in the high price case.

World Liquids Supply Is Projected To Remain Diversified in All Cases

Figure 34. World liquids production shares by region in three cases, 2007 and 2030 (percent)



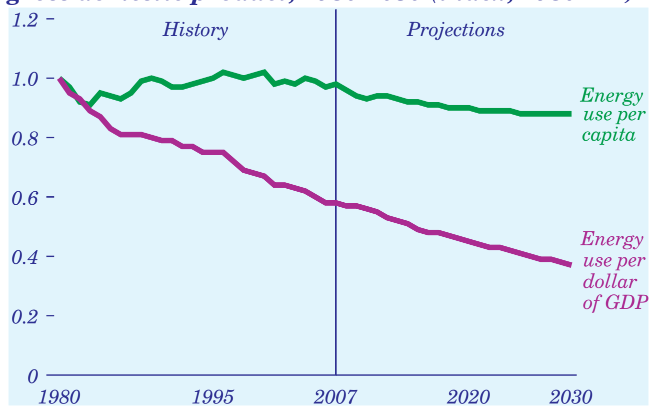
OPEC production decisions are the most significant factor underlying differences among the price cases. The *AEO2009* reference case assumes that OPEC will maintain a share of approximately 40 percent of total world liquids production through 2030, consistent with recent trends. In the high price case, OPEC reduces its market share to about 30 percent; in the low price case, OPEC's share grows to nearly 50 percent (Figure 34). In all the cases, total liquids production by countries in the Organization for Economic Cooperation and Development (OECD) is between 22 and 26 million barrels per day in 2030, constrained mainly by resource availability rather than price or political concerns.

In the high price case, several non-OPEC countries with large resource holdings (including Russia, Brazil, and Kazakhstan) either maintain or further restrict opportunities for investment in resource development, limiting their contributions to total liquids supply. Political, fiscal, and resource conditions in each of those countries are unique; however, all will require domestic and foreign investment to develop new projects and maintain infrastructure, and all have either resisted encouraging such investment or indicated that they might enact restrictions on foreign investment.

In the low price case, several resource-rich nations, including Russia and Venezuela, adopt new legislation or fiscal regimes in order to encourage foreign investment in the development of their resources. As a result, the largest increases in liquids production among the non-OPEC countries are in Kazakhstan, Russia, and Brazil.

Average Energy Use per Person Declines Through 2030

Figure 35. Energy use per capita and per dollar of gross domestic product, 1980-2030 (index, 1980 = 1)



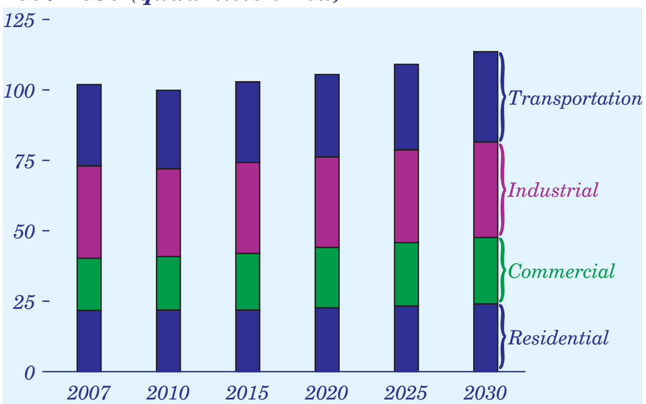
Growth in energy use is linked to population growth through increases in housing, commercial floorspace, transportation, manufacturing, and services. Since 1980, U.S. energy use per capita has remained relatively stable, between 310 and 360 million Btu per person. In periods of high energy prices (particularly, oil prices) energy consumption per capita has tended to be at the low end of the range, and in periods of low energy prices it has tended to move toward the high end. With the expectation that oil prices will remain high throughout the projection period, coupled with recent legislation enacted to increase energy efficiency, energy use per capita in the reference case drops below 310 million Btu in 2020 and continues a slow decline through 2030 (Figure 35).

Improvements in energy efficiency in response to higher CAFE standards and more stringent standards for lighting contribute to the decline in energy use per capita. Other contributing factors include moderate GDP growth and a decline in industrial energy use per dollar of output, as less energy-intensive industries provide a growing share of industrial production.

Energy intensity (energy use per 2000 dollar of GDP) also declines in all the end-use sectors in the reference case, as a result of both structural changes and efficiency improvements. The smallest decline from 2007 through 2030 is projected for the commercial sector, where recent energy legislation has only a small impact. In addition, growth in commercial floorspace outpaces housing growth.

Buildings and Transportation Sectors Lead Increases in Primary Energy Use

Figure 36. Primary energy use by end-use sector, 2007-2030 (quadrillion Btu)



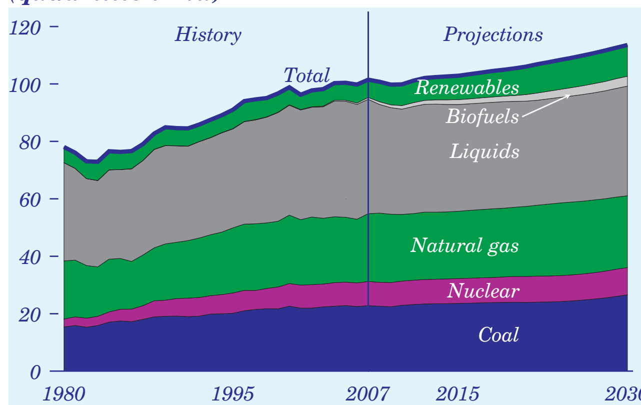
Total primary energy consumption, including for electricity generation, grows by 0.5 percent per year from 2007 to 2030 in the reference case (Figure 36). The fastest growth is projected for the commercial sector (1.1 percent), which has the smallest share of end-use energy demand. Growth in commercial energy use is led by increases for office equipment, ventilation, and "other uses," including service station equipment, automated teller machines, telecommunications equipment, and medical equipment—most of which are powered by electricity. Residential energy use grows by 0.4 percent per year, with increases resulting from population growth, more personal computer use, and shifts to larger formats for television sets being offset in large part by efficiency improvements in lighting and appliances, as required by EISA2007.

Energy use for transportation also grows by 0.5 percent per year in the reference case. All growth in transportation energy consumption results from increased fuel use for freight trucks and air transportation. For LDVs, which make up the largest segment of energy use in the transportation sector, rising energy prices and enhanced CAFE standards offset increases in the number of vehicles sold and miles traveled.

Energy consumption in the industrial sector increases by only 0.1 percent per year. EISA2007 requires more use of biofuels in the transportation sector. Conversion of biomass to ethanol or diesel fuel in the industrial sector produces liquids with lower Btu content than the biomass feedstock, creating heat that can be used to power on-site equipment or to generate electricity for sale to the grid.

Renewable Sources Lead Rise in Primary Energy Consumption

Figure 37. Primary energy use by fuel, 1980-2030 (quadrillion Btu)



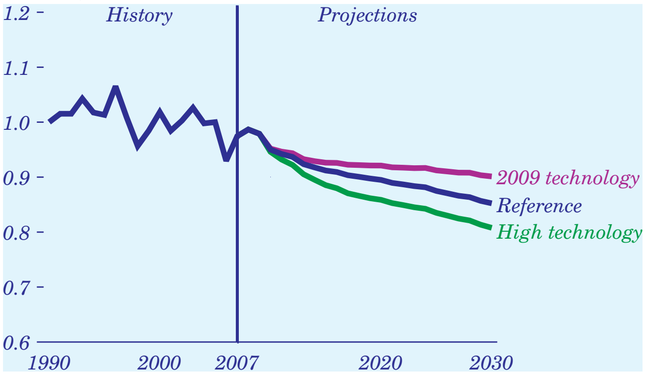
Primary energy consumption in the end-use sectors grows by 0.5 percent per year from 2007 to 2030, with annual demand for renewable fuels increasing the fastest—including E85 and biodiesel fuels for light-duty vehicles, biomass for co-firing at coal-fired electric power plants, and byproduct streams in the paper industry captured for energy production. Biomass consumption increases by 4.4 percent per year on average from 2007 to 2030 and makes up 22 percent of total marketed renewable energy consumption in 2030, compared with 10 percent in 2007.

The petroleum share of liquid fuel consumption in the transportation sector declines somewhat, as consumption of alternate fuels (such as biodiesel and E85) and blending components (such as ethanol) increases as a result of the RFS mandate in EISA2007. Overall, consumption of liquid fuels in the transportation sector—particularly for LDVs—continues to increase through 2030. After ethanol and biodiesel, the fastest growth in renewable energy consumption in the end-use sectors is projected for biomass use. In he mid-term (from 2014 to 2023), a decline in real output from the chemical industry leads to a reduction in demand for LPG and petrochemical feedstocks in the industrial sector.

Natural gas use increases by 0.2 percent per year over the projection period, including steady growth in the commercial sector, where it is used for on-site electricity generation. Coal consumption increases by 0.7 percent per year on average (Figure 37). Nearly all the increase results from the use of coal as a feedstock in the industrial sector, at new CTL plants.

Residential Energy Use per Capita Varies With Technology Assumptions

Figure 38. Residential delivered energy consumption per capita in three cases, 1990-2030 (index, 1990 = 1)

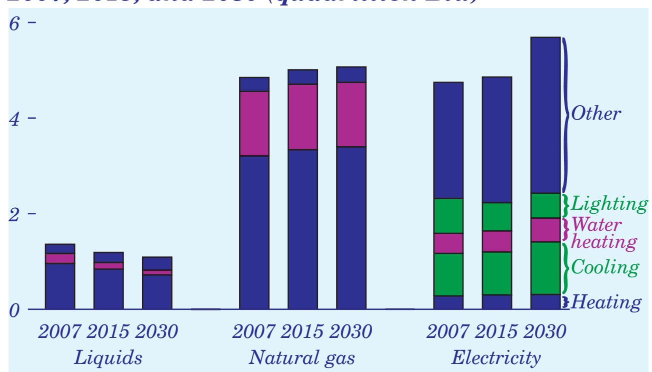


Over the past 10 years, the weather has generally been warmer than the 30-year average, causing residential energy use per person to remain mostly below its 1990 level. Increases in energy efficiency also have contributed to lower residential energy use, while consumer preference for larger homes and new energy-using technologies has worked in the opposite direction. Given the preponderance of warmer winters and summers, the *AEO2009* projections define normal weather as the average of the most recent 10 years of historical data, which decreases the need for heating fuels, such as natural gas and fuel oil, and increases the need for electricity used for air conditioning, all else being equal.

In the *AEO2009* projections, residential energy use per capita changes with assumptions about the rate at which more efficient technologies are adopted. The 2009 technology case assumes no increase in the efficiency of equipment or building shells beyond those available in 2009. The high technology case assumes lower costs, higher efficiencies, and earlier availability of some advanced equipment. In the reference case, residential energy use per capita is projected to fall below the 2006 level (the lowest since 1990) after 2012. In the 2009 technology case, delivered energy use per capita in the residential sector remains near the 2006 level through 2030, when it is 6 percent higher than projected in the reference case (Figure 38). In the high technology case, delivered energy use per capita in the residential sector falls below the 2006 level after 2011, reaching a 2030 level that is 5 percent below the reference case projection.

Household Use of Electricity Continues To Grow

Figure 39. Residential delivered energy consumption by fuel and service, 2007, 2015, and 2030 (quadrillion Btu)

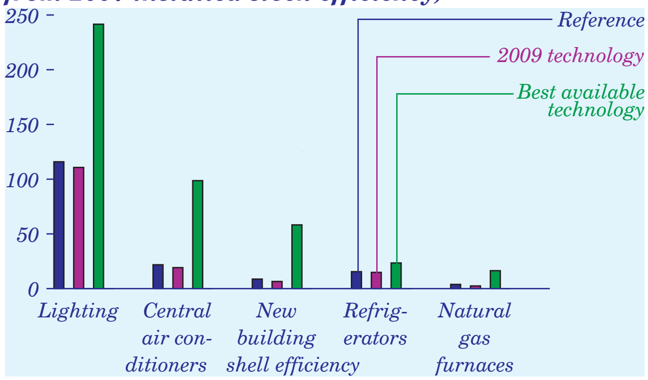


Residential electricity use has increased by 23 percent over the past decade, as efficiency improvements have been more than offset by increases in air conditioning use and the introduction of new applications. That trend continues in *AEO2009* (Figure 39). In 2030, electricity use for home cooling in the reference case is 24 percent higher than the 2007 level, as the U.S. population continues to migrate to the South and West, and older homes are converted from room air conditioning to central air conditioning. A projected 24-percent increase in the number of households also increases the demand for appliances, and total electricity use in the residential sector increases by 20 percent from 2007 to 2030 in the reference case. The share of electricity used for "other appliances" grows from 51 percent in 2007 to 58 percent in 2030, as home electronics continue to proliferate, and efficiency gains in traditional end uses (such as lighting) foster reductions in energy use per household.

Natural gas and liquid fuels are used in the residential sector primarily for space and water heating. Few new uses have emerged over the past decade, and few are expected in the future. Thus, natural gas and liquids consumption per household falls as the energy efficiency of furnaces and building components continues to improve. Demand for space and water heating per household declines by 19 percent from 2007 to 2030, as the population shifts from colder to warmer climates. Technologies that can reduce demand for natural gas in the residential sector include condensing gas furnaces, which can attain 95 percent efficiency, and tankless (instantaneous) water heaters, which can attain 80-percent efficiency, representing an increase of 36 percent over the current standard.

Increases in Energy Efficiency Are Projected To Continue

Figure 40. Efficiency gains for selected residential appliances in three cases, 2030 (percent change from 2007 installed stock efficiency)

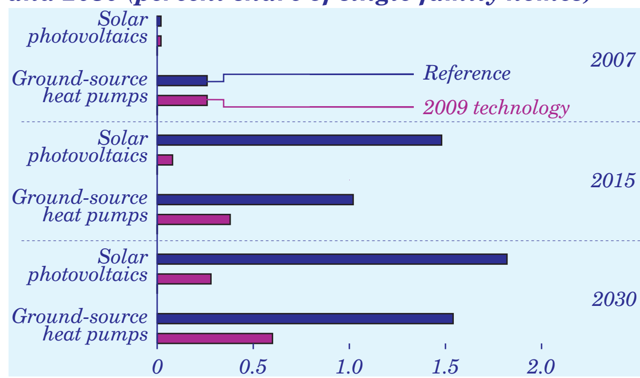


The energy efficiency of purchased equipment plays a key role in determining the types and amounts of energy used in residential buildings. Delivered energy use per household declines in the *AEO2009* reference case at an average annual rate of 0.6 percent, even as the average square footage of households rises and the penetration of appliances, especially electronics, continues to grow. Stock turnover and the resulting purchase of more efficient equipment account for most of the decline in residential energy intensity, while rising energy prices and more rapid growth of households in the Sunbelt regions together account for about one-third of the decline.

In the 2009 technology case, which assumes no efficiency improvement in available appliances beyond 2009 levels, normal stock turnover still results in higher average energy efficiency for most end uses in 2030, as older, less efficient appliances in the existing stock are replaced (Figure 40). The best available technology case assumes that consumers will install only the most efficient products available, regardless of cost, at normal replacement intervals, and that new buildings will meet the most energy-efficient specifications available. Because purchases of new energy-efficient products (including compact fluorescent bulbs, solid-state lighting, and condensing gas furnaces) cut energy use without reducing service levels, residential delivered energy consumption in 2030 is 29 percent lower in the best available technology than in the 2009 technology case and 25 percent lower than in the reference case. In the best available technology case, residential delivered energy intensity declines by 1.8 percent per year, and residential electricity use declines by almost 1 percent per year.

EIEA2008 Tax Credit Increases Installations of Efficient Equipment

Figure 41. Residential market penetration by renewable technologies in two cases, 2007, 2015, and 2030 (percent share of single-family homes)



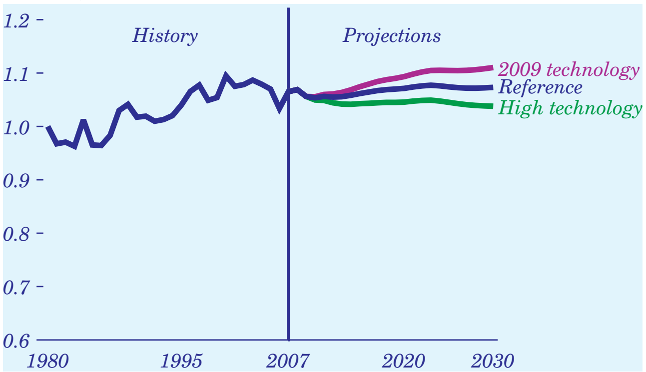
In the past, in a market dominated by such traditional energy resources as liquids, natural gas, and electricity, renewables have claimed only a tiny share of residential energy use. Wood-burning stoves and solar-powered water heaters are the most common renewable energy technologies used in households today; however, EIEA2008 provides sizable tax credits through 2016 for purchases of energy-efficient ground-source heat pumps and solar PV systems.

Ground-source heat pumps, which extract heat from the ground to provide energy for heating and cooling, are an efficient but relatively expensive alternative to traditional air-source heat pumps. Nationwide, roughly 35,000 ground-source heat pumps were installed in residential buildings in 2007. In the *AEO2009* reference case, which includes the $2,000 EIEA2008 tax credit for ground-source heat pumps, installations average 90,264 per year. As a result, their market share increases more than fivefold over their 2007 share, to 1.5 percent in 2030.

The outlook for solar PV installations is similar. Although residential solar PV has received a 30-percent Federal tax credit in the past few years, that credit was capped at $2,000. EIEA2008 removes the cap, allowing the average tax credit to reach roughly $10,000 for a 3.5-kilowatt system, thus enhancing the economics of residential installations considerably. Over the period of the tax credit (2009-2016), more than 1.6 million residential solar PV units are projected to be installed in the reference case (Figure 41).

Commercial Energy Use per Capita Is Projected To Level Off

Figure 42. Commercial delivered energy consumption per capita in three cases, 1980-2030 (index, 1980 = 1)

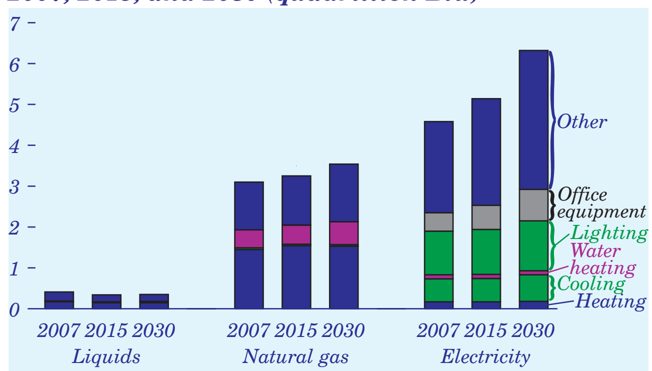


Assumptions about the availability and adoption of energy-efficient technologies help define the range for delivered commercial energy use per person in the *AEO2009* projections. Energy consumption per capita, which increased steadily in the 1980s and 1990s, stabilizes in the *AEO2009* reference case as efficiency improvements offset growth in demand for energy services (Figure 42). In the 2009 technology case, in which equipment and building shell efficiency improvements are limited to those available in 2009, commercial energy use per capita continues to increase through 2020 before leveling off. In the high technology case, which assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment and building shells, future commercial energy use per capita remains below current levels, falling to 3.3 percent below the reference case level in 2030. Lower electricity use accounts for most of the difference from the reference case.

Growth in commercial floorspace averages 1.3 percent per year from 2007 to 2030 in the reference case, following trends in economic and population growth. The reference case assumes future improvements in efficiency for available equipment and building shells, as well as increased demand for services. The purchase of more efficient equipment in response to high energy prices offsets the increase in energy consumption that would have occurred with floorspace expansion, leading to a decline in commercial energy intensity in the *AEO2009* projections across all cases. The projected average annual declines in delivered energy intensity from 2007 to 2030 range from 0.1 percent per year in the 2009 technology case to 0.4 percent per year in the high technology case.

Electricity Leads Expected Growth in Commercial Energy Use

Figure 43. Commercial delivered energy consumption by fuel and service, 2007, 2015, and 2030 (quadrillion Btu)

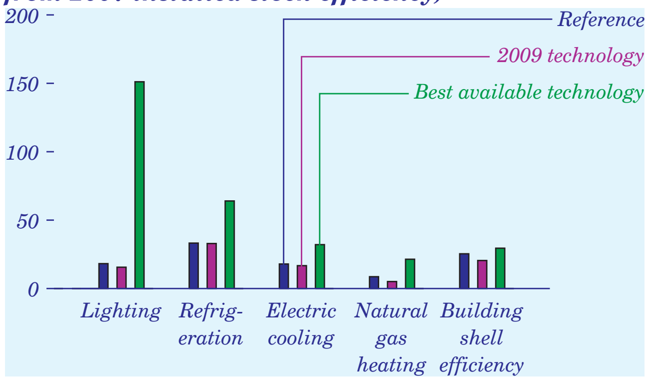


In the *AEO2009* reference case, growth in disposable income increases demand for services from hotels, restaurants, stores, theaters, and other commercial establishments, which increasingly depend on computers and other electronic office equipment for basic services and for business and customer transactions. The growing share of the population over age 65 also increases demand for health care and assisted-living facilities and for electricity to power medical and monitoring equipment at those facilities. In combination with "other" uses (such as telecommunications equipment), those increases offset improved efficiency in the major commercial end uses, so that total commercial electricity use increases by an average of 1.4 percent per year from 2007 to 2030.

Use of natural gas and liquids for heating shows limited growth (Figure 43), as commercial activity reflects the U.S. population shift to the South and West (where space heating requirements are relatively low) and the efficiency of building and equipment stocks improves. Commercial natural gas use grows by 0.6 percent per year on average from 2007 to 2030 in the reference case, including more use of CHP in the later years. Commercial natural gas use in 2030 varies slightly in response to changing economic assumptions, from 3.4 quadrillion Btu in the low growth case to 3.7 quadrillion Btu in the high growth case. Liquid fuels use shows little change over time in the reference case, as concerns about fuel costs and emissions make fuel oil less attractive for CHP. The high and low oil price cases show the widest range for liquid fuels use, from 8 percent below to 19 percent above the reference case projection of 0.6 quadrillion Btu in 2030, respectively.

Technology Provides Potential Energy Savings in the Commercial Sector

Figure 44. Efficiency gains for selected commercial equipment in three cases, 2030 (percent change from 2007 installed stock efficiency)



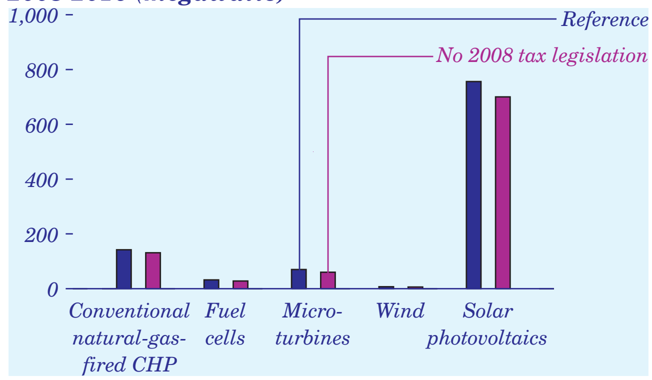
The stock efficiency of energy-consuming equipment in the commercial sector increases in the *AEO2009* reference case as equipment stocks age and are replaced by more energy-efficient technologies (Figure 44). As a result, commercial energy intensity falls by 0.3 percent per year. Stock turnover moderates the growth in energy use that otherwise would occur with a projected 1.3-percent average annual increase in commercial square footage. In addition, rising energy prices contribute about 0.1 percent per year to the decline in energy intensity.

The best available technology case assumes that only the most efficient technologies are chosen, regardless of cost, and that new building shells in 2030 are 29 percent more efficient than the 2007 stock. In the best available technology case, with the adoption of improved heat exchangers for space heating and cooling equipment, solid-state lighting, and more efficient compressors for commercial refrigeration, commercial delivered energy consumption in 2030 is 15 percent lower than in the reference case and 18 percent lower than in the 2009 technology case, and commercial delivered energy intensity declines by 1.0 percent per year from 2007 to 2030.

The 2009 technology case assumes that equipment and building shell efficiencies are limited to those available in 2009. In this case, energy efficiency in the commercial sector still improves from 2007 to 2030, but delivered energy intensity declines by only 0.1 percent per year, because the energy savings that otherwise would result from improving efficiency are offset primarily by increasing penetration of new electric appliances in the commercial sector.

Tax Credits, Advanced Technologies Could Boost Distributed Generation

Figure 45. Additions to electricity generation capacity in the commercial sector in two cases, 2008-2016 (megawatts)



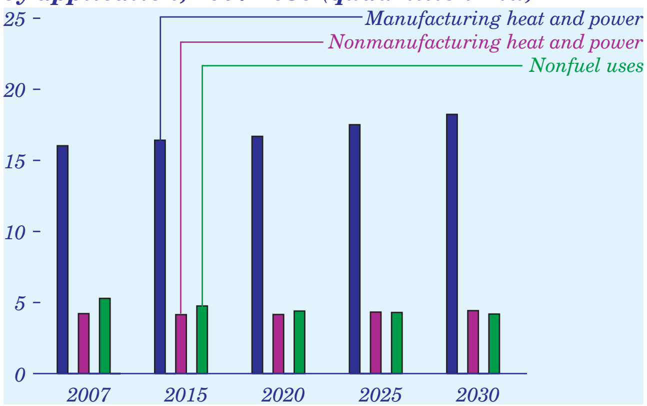
The extension and expansion of ITCs for distributed generation technologies in EIEA2008 result in a 3.2-percent increase in commercial sector electricity generation capacity by 2016 in the *AEO2009* reference case in comparison with the no 2008 tax legislation case. In the reference case, commercial solar PV installations show the largest increase, benefiting from a 30-percent business ITC with no cap on the allowable dollar amount. Conventional natural-gas-fired generating technologies, which are less capital-intensive than most renewable technologies, also receive a boost from the new 10-percent credit for CHP systems in the reference case (Figure 45).

In the high technology case, with more optimistic technology assumptions, electricity generation at commercial facilities in 2030 is 13 billion kilowatthours (37 percent) higher than in the reference case, and most of the increase offsets electricity purchases. In the best available technology case, 18 billion kilowatthours (55 percent) more commercial electricity generation (mostly from solar PV and wind systems) is projected for 2030 than in the reference case.

Some of the heat produced by fossil-fuel-fired generators in CHP applications can be used for water and space heating, increasing the efficiency and attractiveness of the technologies. On the other hand, the additional natural gas used for CHP systems in the commercial sector raises total natural gas consumption in the reference case and offsets some of the reductions in energy costs that result from efficiency gains in end-use equipment and building shells in the high technology and best technology cases.

Manufacturing Takes a Growing Share of Total Industrial Energy Use

Figure 46. Industrial delivered energy consumption by application, 2007-2030 (quadrillion Btu)



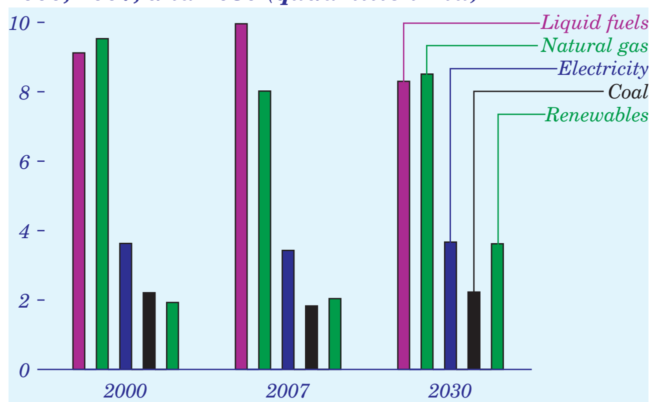
About two-thirds of delivered energy consumption in the industrial sector is used for heat and power in manufacturing. Nonfuel uses of energy fuels, primarily as feedstocks in chemical manufacturing and asphalt for construction, make up one-fifth of the total, and nearly all the rest is used for heat and power in agriculture, mining, and construction. In the reference case, despite a 47-percent increase in industrial shipments, industrial delivered energy consumption grows by only 4 percent from 2007 to 2030, mainly as a result of slow growth or declines in output from most of the energy-intensive manufacturing industries. In the chemical industry, in particular, shipments decline by 10 percent from 2007 to 2030.

Manufacturing energy use for heat and power grows through 2030, with large increases in refining and biofuel production more than offsetting reductions in output for bulk chemicals, iron and steel, and aluminum. In contrast, despite projected recovery in the construction industry, with 23-percent output growth from 2007 to 2030, nonmanufacturing energy use in 2030 is approximately the same as in 2007. Efficiency improvements in diesel- and gasoline-powered construction equipment slow the growth of energy consumption in the nonmanufacturing industries.

Prospects for nonfuel uses of energy depend on output trends in the chemical, agriculture, and construction industries, as well as the potential for synthetic fuel production, including CTL and GTL. In the reference case, efficiency improvements, a shrinking chemical industry, and unfavorable prospects for CTL and GTL contribute to a 21-percent reduction in nonfuel uses of energy from 2007 to 2030 (Figure 46).

Industrial Fuel Choices Vary Over Time

Figure 47. Industrial energy consumption by fuel, 2000, 2007, and 2030 (quadrillion Btu)



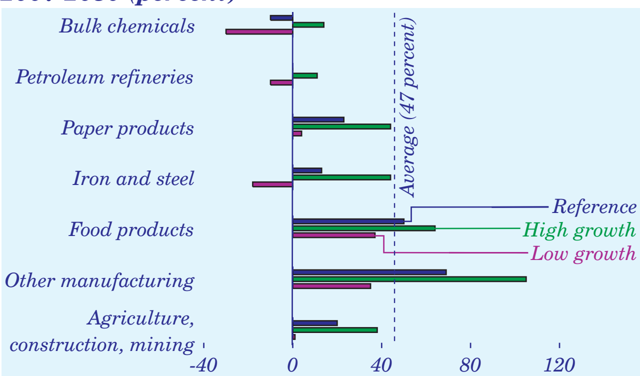
Liquid fuels and natural gas account for 71 percent of industrial delivered energy consumption, with electricity, coal, and renewables accounting for the rest. Because fuel-switching opportunities in existing plants are limited, changes in fuel shares tend to reflect long-term transitions in the mix of industries, as well as impacts of capital investment. In the reference case, natural gas is the leading industrial fuel source in 2030, as opposed to liquid fuels in 2007 (Figure 47). Even so, natural gas use in 2030 remains below its 2000 level. Growth in natural gas use is moderated by a decline in consumption in the chemical industry, which accounted for about one third of total industrial natural gas use in 2007 (excluding natural gas lease and plant fuel). About three-fourths of liquid fuel consumption in the industrial sector is for nonfuel uses or is generated as a byproduct in refining.

Coal use for CTL production more than offsets a decline in such traditional applications as steam generation and coke production as a result of environmental concerns related to emissions from coal-fired boilers, along with manufacturing efficiency improvements that reduce the need for process steam. Metallurgical coal use also declines, reflecting modest growth in the steel industry and the spread of electric arc furnaces.

Modest growth in industrial electricity use reflects efficiency improvements across a wide spectrum of industries, attributable in part to the new motor efficiency standards included in EISA2007. Renewable energy consumption in the industrial sector expands with the projected growth in pulp and paper shipments, which allows more biomass to be recovered from those production processes.

Energy-Intensive Industries Grow Less Rapidly Than Industrial Average

Figure 48. Cumulative growth in value of shipments for industrial subsectors in three cases, 2007-2030 (percent)



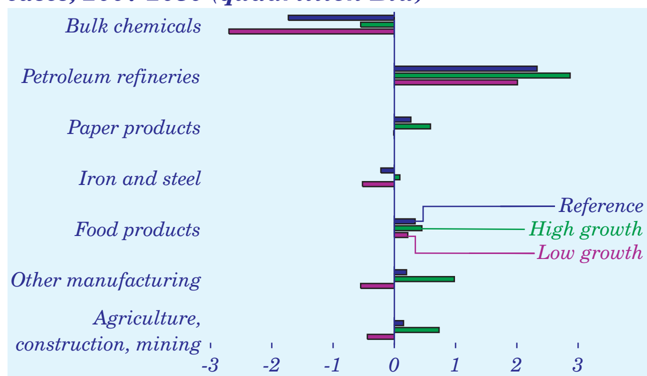
Industrial activity varies across the *AEO2009* economic growth cases, reflecting uncertainty about growth in the economy. Total industrial shipments grow by 47 percent from 2007 to 2030 in the reference case, as compared with 20 percent in the low economic growth case and 74 percent in the high economic growth case. In the near term, however, industrial activity is slowed by the current economic downturn. From 2007 to 2010, shipments decline for many industries (including construction, bulk chemicals, refining, steel, cement, and paper products), and industrial delivered energy use in the reference case falls by about 6 percent before recovering.

A few energy-intensive industries account for a large share of total industrial energy consumption. Ranked by 2007 energy consumption, the top five energy-consuming industries—bulk chemicals, refining, paper, steel, and food—accounted for about 60 percent of total industrial energy use but only 20 percent of total shipments. Those five and the other energy-intensive industries (glass, cement, and aluminum) grow more slowly than the non-energy-intensive industries (Figure 48).

The relatively slow growth of energy-intensive manufacturing industries in the reference case results from increased foreign competition, reduced domestic demand for the raw materials and basic goods they produce, and movement of investment capital to more profitable areas. In general, a shift in manufacturing from basic goods toward less energy-intensive, higher-value products results from the comparative advantage of the technically advanced U.S. economy in international trade.

Energy Consumption Growth Varies Widely Across Industry Sectors

Figure 49. Cumulative growth in delivered energy consumption for industrial subsectors in three cases, 2007-2030 (quadrillion Btu)

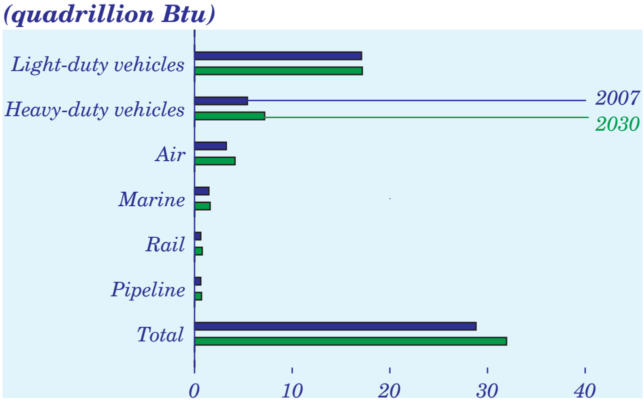


The projections for industrial energy consumption vary by industry and are subject to considerable uncertainty, as reflected in the three economic growth cases (Figure 49). Industrial delivered energy consumption grows by 4 percent from 2007 to 2030 in the reference case, declines by 9 percent in the low economic growth case, and increases by 19 percent in the high economic growth case. In absolute terms, the most significant changes in energy consumption from 2007 to 2030 are in the two largest energy-consuming industries, bulk chemicals and refining. The decline in energy use for bulk chemicals, a major exporting industry, reflects increased competition in foreign markets from countries with access to less expensive energy sources, combined with improvements in energy efficiency. Energy consumption in the refining industry increases—despite a relatively flat trend in overall petroleum demand—given the industry's needs to process heavier crudes, comply with low-sulfur fuel standards, and produce biofuels as mandated in EISA2007.

For the cement and steel industries, delivered energy consumption declines from 2007 to 2030, primarily as a result of relatively slow output growth, expected long-term changes in production technology, and rising energy prices after 2020. Energy use increases in the paper and pulp industry, with rising shipments reversing recent declines, and in the food industry. The decline in aggregate industrial energy intensity, or consumption per real dollar of shipments, is more rapid when a higher rate of economic growth is assumed: 1.7 percent in the high economic growth case, as compared with 1.5 percent in the reference case and 1.2 percent per year in the low growth case.

Growth in Transportation Energy Use Is Expected To Be Slow

Figure 50. Delivered energy consumption for transportation by mode, 2007 and 2030 (quadrillion Btu)



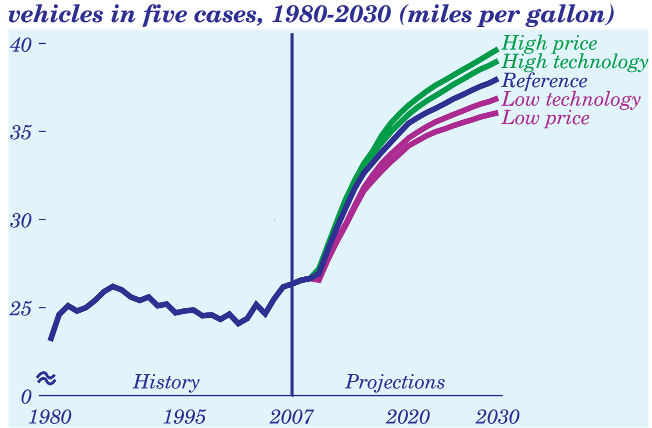
From 2007 to 2030, total delivered energy consumption in the transportation sector grows at an average annual rate of 0.4 percent, from 28.8 quadrillion Btu in 2007 to 31.9 quadrillion Btu in 2030, as compared with the 1.5-percent average rate from 1980 to 2007. Energy use by LDVs levels off in the reference case because of higher energy prices and more stringent CAFE standards, and because growth in demand for air travel also is expected to be slower than in the past.

Energy demand for LDVs (cars, pickup trucks, sport utility vehicles, and vans) increases by just 0.08 quadrillion Btu from 2007 to 2030 (Figure 50), with annual increases in vehicle-miles traveled offset by fuel economy gains resulting from rapidly increasing fuel economy requirements in the near term. Slower growth in income per capita and higher fuel costs also reduce the growth of personal travel, slowing the growth in demand for both highway and aviation fuels. Increases in the fuel efficiency of aircraft also reduce consumption of jet fuel.

More rapid increases in energy demand are projected for other transportation modes. Heavy-duty vehicles (including freight trucks and passenger buses) lead the growth in transportation energy demand over the projection, as a result of their smaller gains in fuel efficiency and expected increases in industrial output. For marine and rail transportation, increases in energy consumption result from the growth of industrial output and growing demand for coal transport. Pipeline energy consumption also increases with the projected growth in volumes of petroleum and natural gas transported.

New CAFE Standards Improve Light-Duty Vehicle Fuel Efficiency

Figure 51. Average fuel economy of new light-duty vehicles in five cases, 1980-2030 (miles per gallon)



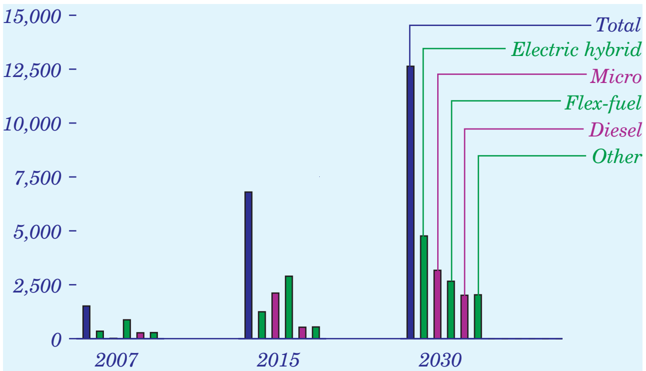
Light trucks (pickups, sport utility vehicles, and vans) have made up a steadily growing share of U.S. LDV sales in recent years [*95*]. Thus, despite technology improvements, the average fuel economy of new LDVs declined from 26.2 mpg in 1987 to a range between 24 and 26 mpg from 1995 to 2006 (Figure 51).

NHTSA has proposed a new attribute-based CAFE standard under which LDV fuel economy would increase rapidly through 2015 and at a slower rate through 2020. Accordingly, in the *AEO2009* reference case, the fuel economy of new LDVs increases by an average of 3.6 percent per year from 2011 to 2015, from 28 mpg to 33 mpg, and by 1.6 percent on average from 2016 to 2020, to 35.5 mpg, slightly exceeding the EISA2007 requirement of 35 mpg in 2020.

In all the *AEO2009* cases, LDV sales in 2030 total about 20 million units; however, the mix of cars and light trucks sold varies across the cases. In the reference case, cars represent 64 percent of total sales in 2030, and LDV fuel economy averages 38.0 mpg. In the high oil price case, cars make up 69 percent of sales in 2030, and LDV fuel economy averages 39.7 mpg. In the low oil price case, cars make up 53 percent of total sales in 2030, and LDV fuel economy averages 36.1 mpg. The economics of fuel-saving technologies improve further in the high technology and high price cases, and consumers buy more fuel-efficient cars and trucks; however, average fuel economy improves only modestly, because the proposed new NHTSA CAFE standards already require significant penetration of advanced technologies, pushing fuel economy improvements to the limit of the technologies included in the model.

Unconventional Vehicle Technologies Exceed 63 Percent of Sales in 2030

Figure 52. Sales of unconventional light-duty vehicles by fuel type, 2007, 2015, and 2030 (thousand vehicles sold)



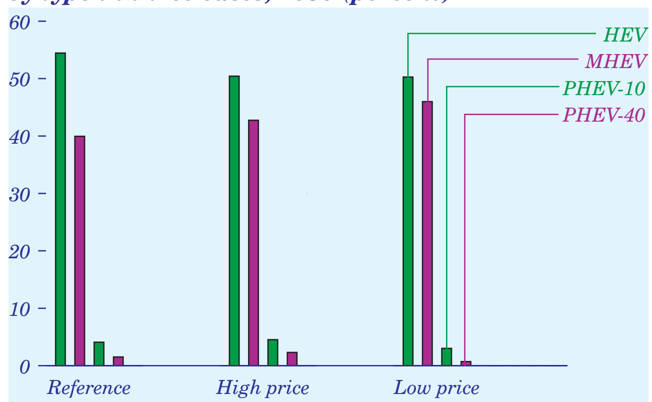
Concerns about oil supply, fuel prices, and emissions have driven the market penetration of unconventional vehicles (vehicles that can use alternative fuels, electric motors and advanced electricity storage, advanced engine controls, or other new technologies). Unconventional vehicle technologies are expected to play a greater role in meeting the new NHTSA CAFE standards for LDVs. Unconventional vehicles account for 63 percent of total new LDV sales in 2030 in the *AEO2009* reference case.

Hybrid vehicles (including both standard hybrids and PHEVs) represent the largest share of the unconventional LDV market in 2030 (Figure 52), at 63 percent of all new unconventional LDV sales and 40 percent of all new LDV sales. Micro hybrids, which allow the vehicle's gasoline engine to turn off by switching to battery power when the vehicle is idling, have the second-largest share, at 25 percent of unconventional LDV sales. Turbo diesel direct injection engines, which can improve fuel economy significantly, capture a 16-percent share of unconventional LDV sales. The availability of ultra-low-sulfur diesel and biodiesel fuels, along with advances in emission control technologies that reduce criteria pollutants, supports the increase in diesel LDV sales.

Currently, manufacturers receive incentives for selling FFVs, through fuel economy credits that count toward CAFE compliance. Although those credits are assumed to be phased out by 2020, FFVs make up 13 percent of all new LDV sales in 2030 in the reference case, in part because of the increased availability and lower cost of E85.

Hybrid Vehicle Shares in 2030 Vary With Fuel Price Assumptions

Figure 53. Sales shares of hybrid light-duty vehicles by type in three cases, 2030 (percent)



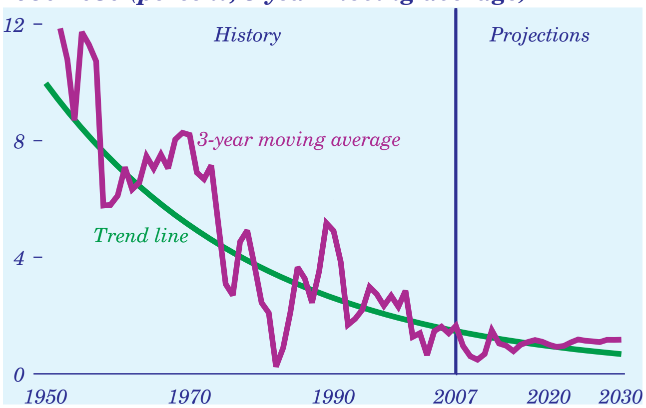
With more stringent CAFE standards and higher fuel prices, unconventional vehicles account for the majority of new LDV sales in 2030 in the reference case, and hybrid electric vehicles claim the largest share of unconventional vehicle sales. Four types of hybrid vehicle are expected to be available for sale in 2030: standard gasoline-electric hybrid (HEV), plug-in hybrid with an all-electric range of 10 miles (PHEV-10), plug-in hybrid with an all-electric range of 40 miles (PHEV-40), and micro hybrid (MHEV).

In the reference case, total hybrid sales increase from 2.3 percent of new LDV sales in 2007 to 20.6 percent in 2015 and 39.6 percent (7.9 million vehicles) in 2030. In the high oil price case, hybrids make up 45.3 percent of new LDV sales in 2030, with sales of 9.1 million; in the low oil price case, they make up 37.8 percent, with sales of 7.6 million.

In the high price case, the mix of hybrid vehicle types sold in 2030 shifts to more fuel-efficient PHEVs: PHEV-10 sales increase from 1.6 percent of LDV sales in the reference case to 2.0 percent in the high price case, and PHEV-40 sales increase from 0.6 percent to 1.0 percent of LDV sales. In the low price case, consumers have less incentive to buy the most efficient (and expensive) PHEVs. Accordingly, vehicle manufacturers increase production of less expensive MHEVs, which claim a larger share of hybrid vehicle sales than they do in the high price case (Figure 53).

Rate of Electricity Demand Growth Slows, Following the Historical Trend

Figure 54. U.S. electricity demand growth, 1950-2030 (percent, 3-year moving average)



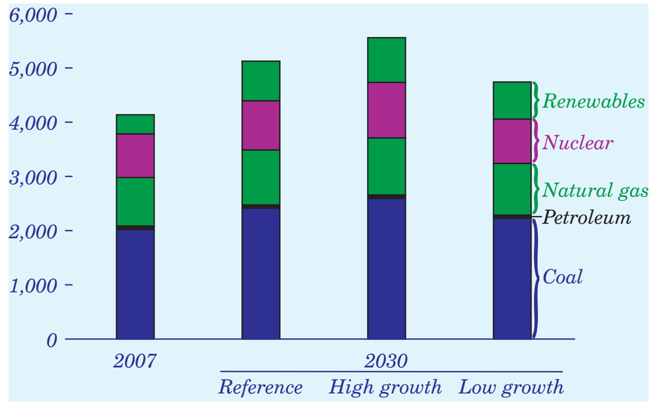
Electricity demand fluctuates in the short term in response to business cycles, weather conditions, and prices. Over the long term, however, electricity demand growth has slowed progressively by decade since 1950, from 9 percent per year in the 1950s to less than 2.5 percent per year in the 1990s. From 2000 to 2007, increases in electricity demand averaged 1.1 percent per year. The slowdown in demand growth is projected to continue over the next 23 years (Figure 54), as a result of efficiency gains in response to rising energy prices and new efficiency standards for lighting, heating and cooling, and other appliances.

In the reference case, electricity demand increases by 26 percent from 2007 to 2030, or by an average of 1.0 percent per year. The largest increase is in the commercial sector (38 percent), where service industries continue to lead demand growth, followed by the residential sector (20 percent) and the industrial sector (7 percent). Population growth and rising disposable incomes increase the demand for products, services, and floorspace, and ongoing population shifts to warmer regions increase the use of electricity for space cooling.

From 2007 levels, electricity demand increases by 36 percent in the high growth case, to 5,323 billion kilowatthours in 2030, compared with an increase of 16 percent in the low growth case, to 4,518 billion kilowatthours in 2030. Plug-in electric hybrid vehicles are not expected to reverse the trend of slowing growth in electricity demand, which increases by only 0.1 percent for every 1 million PHEV-40 vehicles in operation.

Coal-Fired Power Plants Provide Largest Share of Electricity Supply

Figure 55. Electricity generation by fuel in three cases, 2007 and 2030 (billion kilowatthours)



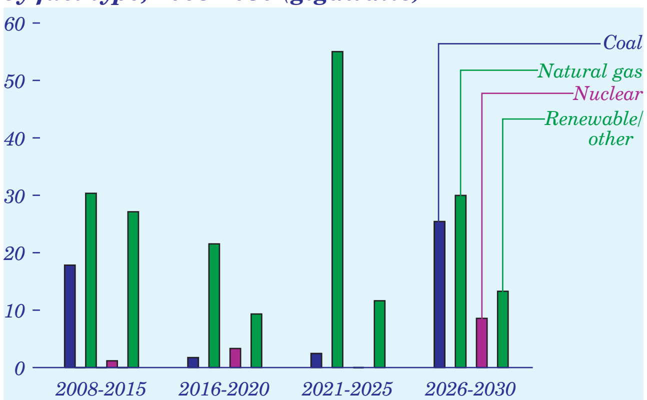
Coal continues to provide the largest share of energy for U.S. electricity generation in the *AEO2009* reference case, with only a modest decrease from 49 percent in 2007 to 47 percent in 2030. Total electricity generation at coal-fired power plants in 2030 is 19 percent higher than the 2007 total (Figure 55). Growth in coal-fired generating capacity is limited by concerns about GHG emissions and the potential for mandated limits, but existing plants continue to be used intensively.

Concerns about GHG emissions have little effect on construction of new capacity fueled by natural gas. The natural gas share of generation increases to 21 percent in 2027, before dropping to 20 percent in 2030, about the same as in 2007. Generation from nuclear power increases by 13 percent from 2007 to 2030, as addition of new units and uprates at existing units increase overall capacity and generation. The nuclear share of total generation falls somewhat, however, from 19 percent in 2007 to 18 percent in 2030. Renewable generation, supported by Federal tax incentives and State renewable programs, increases by more than 100 percent from 2007 to 2030, when it accounts for 14 percent of total generation.

Projected growth in demand for electricity varies with different assumptions about future economic conditions. In 2030, total generation in the high economic growth case is 9 percent above the reference case projection, and in the low economic growth case it is 7 percent below the reference case.

Most New Capacity Uses Natural Gas as Fewer Coal-Fired Plants Are Added

Figure 56. Electricity generation capacity additions by fuel type, 2008-2030 (gigawatts)



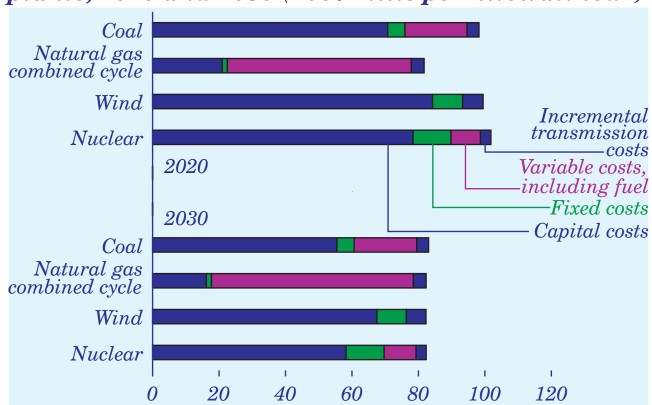
Decisions to add capacity and the choice of fuel type depend on electricity demand growth, the need to replace inefficient plants, the costs and operating efficiencies of different options, fuel prices, and the availability of Federal tax credits for some technologies. With growing electricity demand and the retirement of 30 gigawatts of existing capacity, 259 gigawatts of new generating capacity (including end-use CHP) will be needed between 2007 and 2030.

Natural-gas-fired plants account for 53 percent of capacity additions in the reference case, as compared with 22 percent for renewables, 18 percent for coal-fired plants, and 5 percent for nuclear (Figure 56). Escalating construction costs have the largest impact on capital-intensive technologies, including renewables, coal, and nuclear; but Federal tax incentives, State energy programs, and rising prices for fossil fuels increase the cost-competitiveness of renewable and nuclear capacity. In contrast, uncertainty about future limits on GHG emissions and other possible environmental regulations (reflected in the *AEO2009* reference case by adding 3 percentage points to the cost of capital for new coal-fired capacity) reduces the competitiveness of coal.

Projected capacity additions also are affected by demand growth and by fuel prices. Reflecting slower and faster growth in demand for electricity, capacity additions from 2007 to 2030 total 184 gigawatts and 350 gigawatts in the low and high economic growth cases, respectively. The higher fuel costs in the *AEO-2009* high oil price case lead to fewer additions of natural-gas-fired plants, because fuel costs make up a relatively large share of their total expenditures.

Least Expensive Technology Options Are Likely Choices for New Capacity

Figure 57. Levelized electricity costs for new power plants, 2020 and 2030 (2007 mills per kilowatthour)



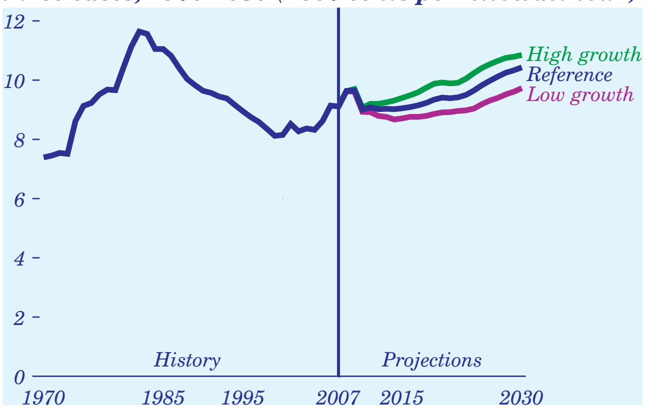
Technology choices for new generating capacity are made to minimize costs while meeting local and Federal emissions constraints. Capacity expansion decisions consider capital, operating, and transmission costs. Typically, coal-fired, nuclear, and renewable plants are capital-intensive, whereas operating (fuel) expenditures account for most of the costs associated with natural-gas-fired capacity (Figure 57) [*96*]. Capital costs depend on such factors as interest rates and cost-recovery periods. Fuel costs can vary according to plant operating efficiency, resource availability, and transportation costs.

Regulatory uncertainty affects capacity planning decisions. Unless they are equipped with CCS equipment, new coal-fired plants could incur higher costs as a result of higher expenses for siting and permitting. Because nuclear and renewable power plants (including wind plants) do not emit GHGs, however, their costs are not directly affected by regulatory uncertainty.

Capital costs can decline over time as developers gain experience with a given technology. In the *AEO2009* reference case, capital costs are adjusted upward initially, to reflect the optimism inherent in early public estimates of project costs. The costs decline as project developers gain experience, and the decline continues at a progressively slower rate as more units are built. Operating efficiencies also are assumed to improve over time, and variable costs could therefore be reduced unless increases in fuel costs exceed the savings from efficiency gains.

Electricity Prices Moderate in the Near Term, Then Rise Gradually

Figure 58. Average U.S. retail electricity prices in three cases, 1970-2030 (2007 cents per kilowatthour)



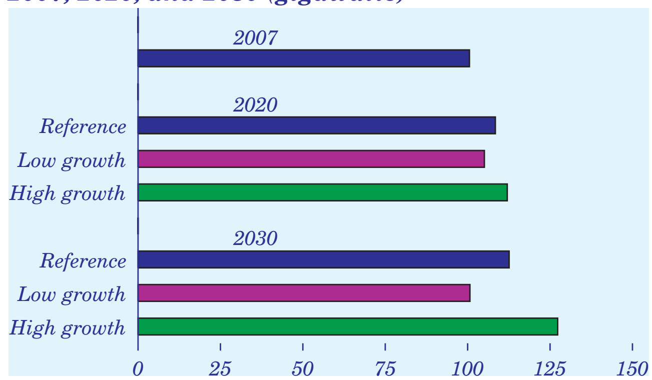
In recent years, real electricity prices (in 2007 dollars) have increased sharply, as fuel costs and capital costs have risen rapidly and restructuring initiatives that constrained price increases have ended. In the *AEO2009* reference case, real electricity prices fall in the near term when fuel prices decline during the economic slowdown. With economic recovery, real electricity prices stabilize at 9.0 cents per kilowatthour in 2010, then remain at that level for several years, while fuel prices remain relatively low and new coal- and natural-gas-fired capacity comes on line. Real electricity prices begin to rise steadily after 2015, as fuel prices increase more rapidly and the need for new capacity grows. Much of the new renewable capacity is required by State renewable mandates.

Real retail electricity prices increase to 10.4 cents per kilowatthour in 2030 in the reference case (Figure 58). They are higher in the high economic growth case, reaching 10.8 cents per kilowatthour in 2030 as stronger economic growth leads to more rapid growth in electricity demand. Electricity prices are lower in the low economic growth case, at 9.7 cents per kilowatthour in 2030.

Transmission costs, while remaining a relatively small component of delivered electricity prices, increase by 35 percent from 2007 to 2030 because of the additional investment needed to meet electricity demand growth, alleviate existing transmission constraints and bottlenecks, facilitate the operation of competitive wholesale energy markets, and link new generation from remote wind facilities with demand centers.

EPACT2005 Tax Credits Are Expected To Stimulate Some Nuclear Builds

Figure 59. Electricity generating capacity at U.S. nuclear power plants in three cases, 2007, 2020, and 2030 (gigawatts)

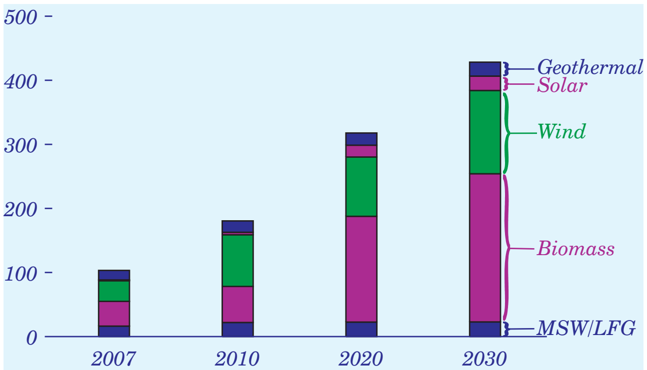


In the *AEO2009* reference case, nuclear power capacity increases from 100.5 gigawatts in 2007 to 112.6 gigawatts in 2030, including 3.4 gigawatts of expansion at existing plants, 13.1 gigawatts of new capacity, and 4.4 gigawatts of retirements. The reference case includes a second unit in 2014 at the Watts Bar site, where construction was halted in 1988 after being partially completed. Rising costs for construction materials have greatly increased the estimated cost of new nuclear plants, which when combined with the current instability of financial markets makes new investments in nuclear power uncertain. In the reference case, some 10 new nuclear power plants are completed through 2030. The first few are eligible for the EPACT2005 PTC. Most existing nuclear units continue to operate through 2030, based on the assumption that they will apply for and receive operating license renewals. Seven units, totaling 4.4 gigawatts, are retired after 2028, when they reach the end date of their original licenses plus a 20-year renewal.

In the *AEO2009* projections, nuclear capacity additions vary with assumptions about overall demand for electricity and the prices of other fuels (Figure 59). The amount of nuclear capacity added also is sensitive to assumptions about future plans and policies for limiting or reducing GHG emissions. Across the oil price and economic growth cases, nuclear capacity additions from 2007 to 2030 range from 1 to 28 gigawatts. In the low economic growth case, with falling electricity demand and rising interest rates, new nuclear plants are not economical. More new nuclear capacity is built in the high growth and high oil price cases, because overall capacity requirements are higher and/or alternatives are more expensive.

Biomass and Wind Lead Projected Growth in Renewable Generation

Figure 60. Nonhydroelectric renewable electricity generation by energy source, 2007-2030 (billion kilowatthours)

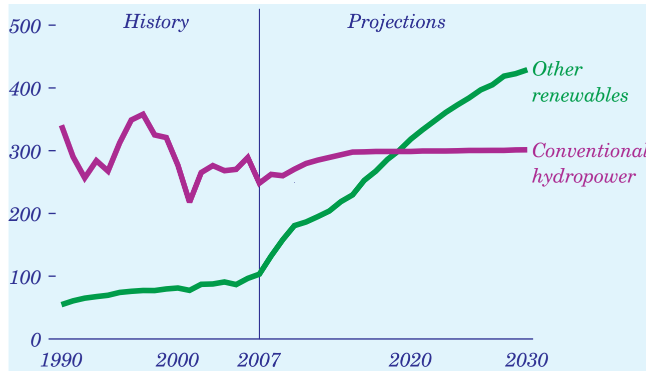


The potential for growth in electricity generation from wind power depends on a variety of factors, including fossil fuel costs, State renewable energy programs, technology improvements, access to transmission grids, public concerns about environmental and other impacts, and the future of the Federal PTC for wind, which is scheduled to expire at the end of 2009. Other renewable technologies are guaranteed a tax credit for an additional year. In the *AEO2009* reference case, generation from wind power increases from 0.8 percent of total generation in 2007 to 2.5 percent in 2030 (Figure 60). Generation from biomass, both dedicated and co-firing, grows from 39 billion kilowatthours in 2007 (0.9 percent of the total) to 231 billion kilowatthours (4.5 percent) in 2030. Generation from geothermal facilities also increases but at such a slow rate that it does not gain market share. Current assessments show limited potential for expansion at conventional geothermal sites. Enhanced geothermal development remains economically infeasible.

The principal reason for the robust growth of renewable electricity generation in the end-use sectors, which is included in the totals above, is the EISA2007 renewable fuels mandate. Biorefineries producing cellulosic ethanol use residues from the biomass feedstock for electricity production. Generation from biomass comprises nearly 80 percent, or 91 billion kilowatthours, of end-use renewable electricity in 2030. Solar technologies in general remain too costly for grid-connected applications, but demonstration programs and State policies support some growth in central-station solar PV, and small-scale, customer-sited PV applications grow rapidly [*97*].

Technology Advances, Tax Provisions Increase Renewable Generation

Figure 61. Grid-connected electricity generation from renewable energy sources, 1990-2030 (billion kilowatthours)

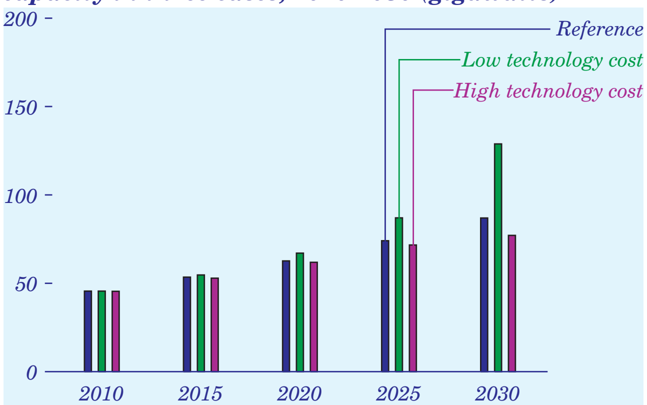


The *AEO2009* reference case includes both State RPS requirements and a risk premium on high-carbon generating technologies. As a result, total renewable electricity generation grows by nearly 380 billion kilowatthours, to 730 billion kilowatthours (14.2 percent of total domestic power production) in 2030. Environmental concerns and a scarcity of new large-scale sites limit the growth of conventional hydropower, and from 2007 to 2030 its share of total generation remains between 6 percent and 7 percent. Generation from nonhydroelectric alternatives increases, bolstered by legislatively mandated State RPS programs, technology advances, and State and Federal supports (Figure 61). Although the Federal PTC is assumed to expire after 2009 for wind and after 2010 for other renewables, nonhydropower renewable generation increases from 2.5 percent of total generation in 2007 to 8.3 percent in 2030.

Wind and biomass are the largest sources of electricity among the nonhydropower renewables. Initially helped by the Federal PTC, their growth continues as States meet their RPS requirements and more States enact RPS programs each year. Central-station solar is also growing rapidly in California. Although the technology remains costly, several credible project announcements have been made that would lead to capacity expansion in the hundreds of megawatts. Moreover, as States continue to organize regional climate pacts, renewable generation will become more prominent in carbon-constrained regions. The Northeast RGGI is the only such program included in the *AEO2009* reference case, but western States are moving forward quickly with their own programs.

Higher or Lower Costs Affect Trends in Renewable Generation Capacity

Figure 62. Nonhydropower renewable generation capacity in three cases, 2010-2030 (gigawatts)

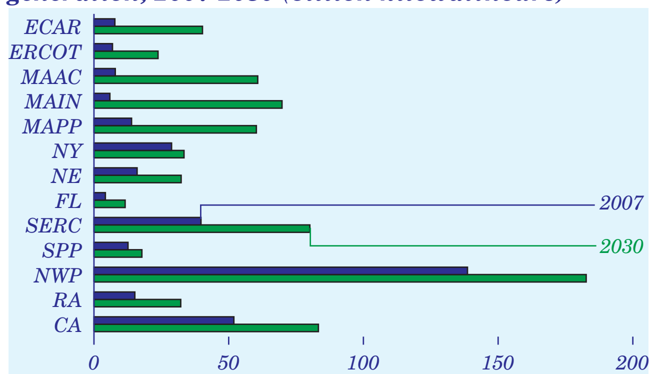


If the costs of renewable generation technologies decline significantly faster than projected in the *AEO-2009* reference case, there may be more new renewable capacity than is needed to meet State renewable generation mandates. The low renewable technology cost case assumes costs 25 percent lower than in the reference case in 2030, resulting in 38 percent more new wind capacity and 200 percent more new dedicated biomass capacity. New end-use solar capacity in 2030 is 49 percent above the reference case level, although the technology remains too expensive for widespread use in bulk power markets; geothermal, hydroelectric, and municipal solid waste capacity shows little change, because economical resources are limited. A significant increase in dedicated biomass capacity in the low cost case draws biomass away from less efficient co-firing operations and helps producers meet State RPS requirements.

In the *high renewable technology cost case*, the costs for renewable capacity remain at the reference case levels and "dedicated energy crops" are not developed, resulting in slightly less new renewable capacity in 2030 than in the reference case (Figure 62). State mandates still are expected to guarantee a significant amount of growth in renewable capacity, however, even with the higher costs. In the high cost case, biomass co-firing operations make a larger contribution to RPS compliance than in the reference case. Although many State RPS laws include cost containment measures that may limit overall compliance if renewable generation is more expensive than projected in the reference case, many of those provisions either are discretionary or cannot be analyzed fully in the high cost case.

State Portfolio Standards Increase Generation from Renewable Fuels

Figure 63. Regional growth in nonhydroelectric renewable electricity generation, including end-use generation, 2007-2030 (billion kilowatthours)



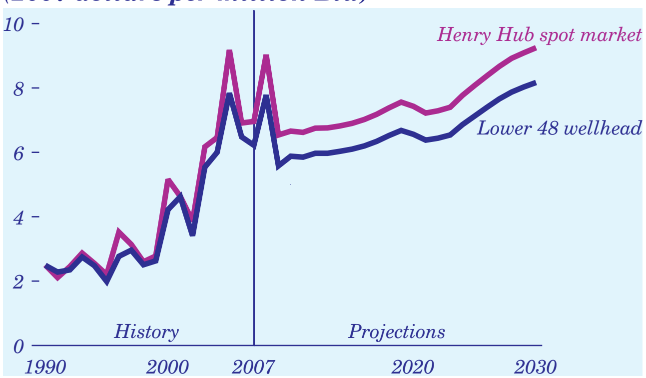
As of early November 2008, 28 States and the District of Columbia had legislatively mandated RPS programs. The mandatory programs are included in the reference case, but States' voluntary goals are not. Because NEMS does not provide projections at the State level, the reference case assumes that most States will reach their goals within each program's legislative framework, and the results are aggregated at the regional level. In some States, however, compliance could be limited by authorized funding levels for the programs. For example, California is not expected to meet its renewable energy targets because of limits on the authorized funding for its RPS program.

By region, the fastest growth in nonhydroelectric renewable generation is projected for MAIN (Figure 63). The largest share of wind power is in the MAIN region, which includes Illinois, Wisconsin, and parts of Michigan and Missouri. In Texas, generation from wind power grows until the Federal PTC expires on December 31, 2010, and resumes growth after 2020, when natural gas prices begin to rise more rapidly. Solar and geothermal energy are used in the Southwest. Biomass generates most of the required renewable energy in the Mid-Atlantic region, which in 2030 contains nearly 53 percent of the Nation's dedicated biomass capacity.

Most NEMS regions include at least one State with an RPS program (see Figure F2 in Appendix F for a map of the regions). The only area without widespread RPS programs is the Southeast, where North Carolina is the only State with an enforceable RPS.

Natural Gas Prices Rise As More Expensive Resources Are Produced

Figure 64. Lower 48 wellhead and Henry Hub spot market prices for natural gas, 1990-2030 (2007 dollars per million Btu)



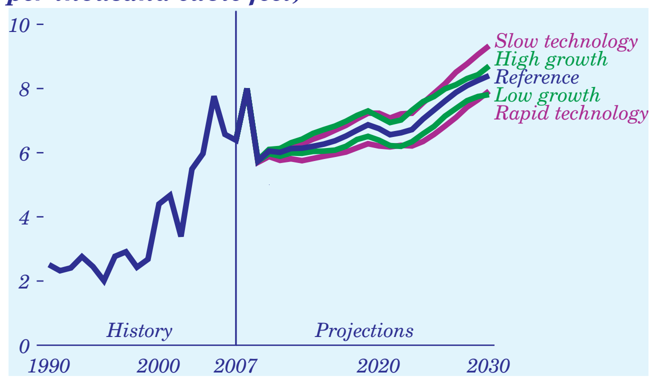
Average lower 48 wellhead prices for natural gas generally increase in the reference case, as more expensive domestic resources are used to meet demand. Prices decline for a brief period after the Alaska pipeline begins operation in 2020, but the market quickly absorbs the additional natural gas supplies from Alaska, and prices resume their rise (Figure 64).

Henry Hub spot market prices and delivered end-use natural gas prices generally follow the trend in lower 48 wellhead prices; however, delivered prices also are subject to variation in average transmission and distribution rates and resulting margins, as reflected in the difference between the average delivered price and the average supply price for natural gas. Some new pipelines are built to bring supplies to market and to reach new customers, but the bulk of the pipeline system is already in place, and revenue requirements for those segments decline as capital is depreciated. Consequently, transmission and distribution margins for natural gas delivered to the industrial and electric power sectors either remain flat or decline.

Natural gas distribution rates are determined in large part by consumption levels per customer, which decline in the residential and commercial sectors over the projection period. As a result, fixed costs are distributed over a smaller customer base, leading to slight increases in transmission and distribution margins in those sectors. In the transportation sector, transmission and distribution margins for natural gas used as fuel in CNG vehicles decline in real terms, as motor fuels taxes remain constant in nominal terms.

Prices Vary With Economic Growth and Technology Progress Assumptions

Figure 65. Lower 48 wellhead natural gas prices in five cases, 1990-2030 (2007 dollars per thousand cubic feet)



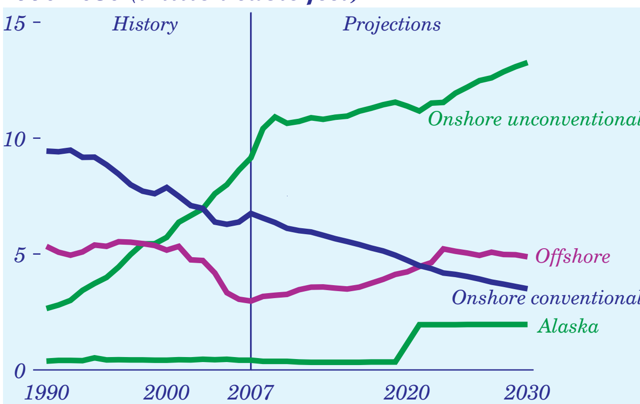
The extent to which natural gas prices increase in the *AEO2009* reference and alternative cases depends on assumptions about economic growth rates and the rate of improvement in natural gas exploration and production technologies. Technology improvements reduce drilling and operating costs and expand the economically recoverable resource base.

Technology improvement is particularly important in the context of growing investment in production of natural gas from shale formations, which generally can be produced more efficiently than the natural gas contained in conventional formations, but which require relatively high capital expenditures. The reference case assumes that annual technology improvements follow historical trends. In the rapid technology case, exploration and development costs per well decline at a faster rate, which allows for more growth in production. More rapid technology improvement puts downward pressure on natural gas prices, mitigated somewhat by higher levels of consumption than in the reference case. In the slow technology case, slower declines in exploration and development costs lead to higher natural gas prices than in the reference case.

In the *AEO2009* high economic growth case, natural gas consumption grows more rapidly, and natural gas prices rise more sharply, than in the reference case. In the low economic growth case, natural gas consumption grows more slowly, and natural gas prices are lower, than in the reference case (Figure 65).

Largest Source of U.S. Natural Gas Supply Is Unconventional Production

Figure 66. Natural gas production by source, 1990-2030 (trillion cubic feet)



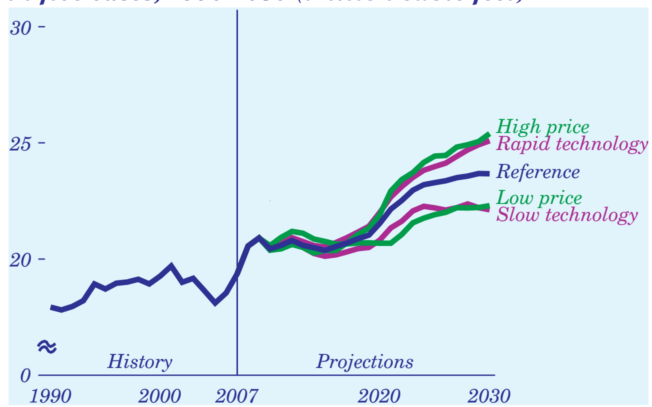
From 2007 to 2030, total natural gas production per year in the reference case increases by more than 4 trillion cubic feet, even as onshore lower 48 conventional production (from smaller and deeper deposits) continues to taper off. Unconventional natural gas is the largest contributor to the growth in U.S. natural gas production, as rising prices and improvements in drilling technology provide the economic incentives necessary for exploitation of more costly resources. Unconventional natural gas production increases from 47 percent of the U.S. total in 2007 to 56 percent in 2030 (Figure 66).

Natural gas in tight sand formations is the largest source of unconventional production, accounting for 30 percent of total U.S. production in 2030, but production from shale formations is the fastest growing source. With an assumed 267 trillion cubic feet of undiscovered technically recoverable resources, production of natural gas from shale formations increases from 1.2 trillion cubic feet in 2007 to 4.2 trillion cubic feet, or 18 percent of total U.S. production, in 2030. The expected growth in natural gas production from shale formations is far from certain, however, and continued exploration is needed to provide additional information on the resource potential.

Offshore production also makes up a significant portion of domestic natural gas supply, accounting for 15 percent of total domestic production in 2007 and 21 percent in 2030. The increase in offshore production is largely from deepwater formations and OCS areas recently released from Congressional moratoria.

World Oil Prices and Technology Progress Affect Natural Gas Supply

Figure 67. Total U.S. natural gas production in five cases, 1990-2030 (trillion cubic feet)



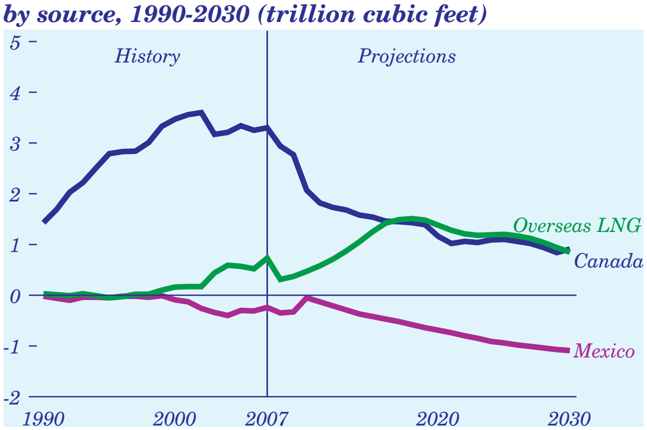
Improvements in natural gas exploration and development technologies reduce drilling costs, increase production capacity, and ultimately lower wellhead prices, increasing both production levels and end-use consumption. More rapid technology improvement raises the potential level of natural gas production and offsets the effects of depletion of the resource base, particularly for onshore conventional resources. In the rapid technology case, natural gas production in 2030 is 1.4 trillion cubic feet higher than in the reference case; in the slow technology case, it is 1.5 trillion cubic feet lower than in the reference case.

The impact of world oil prices on domestic natural gas production is indirect, affecting natural gas consumption and, to a lesser degree, LNG imports. In the high oil price case, natural gas production in 2030 is 1.7 trillion cubic feet higher than in the reference case (Figure 67), with most of the additional supply, 1.2 trillion cubic feet, being used for GTL production. In addition, higher oil prices reduce liquids consumption, leading to a decline in crude oil processing at refineries, so that more natural gas is consumed at refineries to replace still gas that otherwise would be available for refinery use. Higher levels of natural gas consumption for CTL production and refinery use in the high price case are offset to some extent by a decline in natural gas use for electricity generation.

In the low oil price case, refineries use less natural gas. Also, with less expensive crude oil taking a larger share in world energy markets, more natural gas is available for export to the United States as LNG. Domestic natural gas production is therefore lower, and LNG imports are higher, than in the reference case.

U.S. Net Imports of Natural Gas Decline in the Projection

Figure 68. Net U.S. imports of natural gas by source, 1990-2030 (trillion cubic feet)



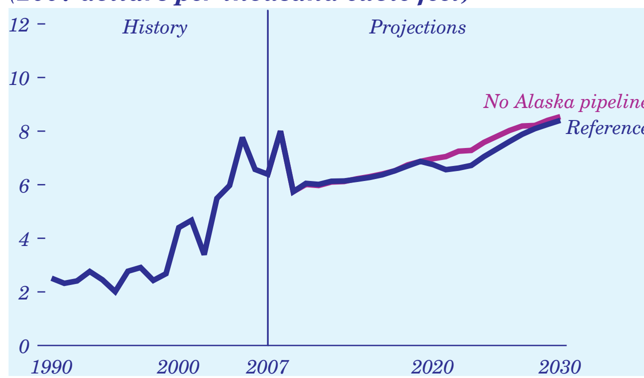
U.S. net imports of natural gas decline in the *AEO-2009* reference case from 16 percent of supply in 2007 to 3 percent in 2030. The reduction is a result primarily of lower imports from Canada and higher exports to Mexico because of growing demand for natural gas in each of those countries. In addition, with relatively high prices and advances in technology, the potential for U.S. domestic natural gas production (particularly from unconventional sources) increases, providing a competitive alternative to imports of LNG.

Conventional natural gas production from Canada's Western Sedimentary Basin has been declining in recent years. In the reference case, Canada's unconventional production does not increase rapidly enough to keep up with domestic demand growth while maintaining current export levels. For Mexico, U.S. pipeline exports are needed to meet the country's growth in demand for natural gas, which is not matched by increases in domestic production and LNG imports.

In the United States, LNG imports peak at 1.5 trillion cubic feet in 2018 before declining to 0.8 trillion cubic feet in 2030 (Figure 68), despite projected U.S. regasification capacity of 5.2 trillion cubic feet. The near-term increase is the result of growth in world liquefaction capacity, which temporarily exceeds world demand, making LNG available to the U.S. market—particularly in the summer to fill storage facilities. In the longer term, high LNG prices (which are tied to oil prices in many markets) and ample domestic natural gas supplies reduce U.S. demand for LNG imports; however, the amount of LNG available to U.S. markets could change if world natural gas consumption differs from the levels projected in the reference case.

With No Alaska Pipeline, Lower 48 Prices for Natural Gas Are Higher

Figure 69. Lower 48 wellhead prices for natural gas in two cases, 1990-2030 (2007 dollars per thousand cubic feet)



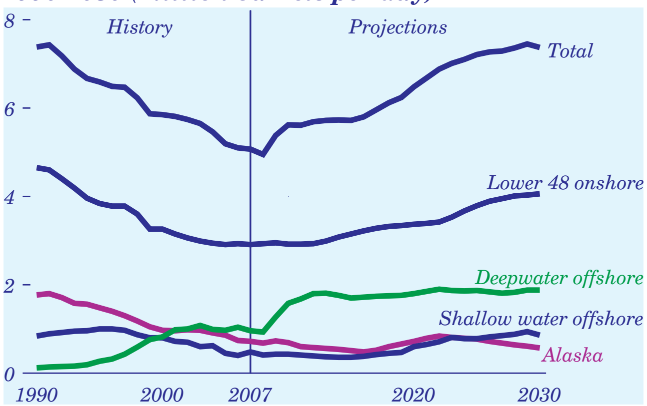
The *AEO2009* reference case assumes that a proposed pipeline to transport natural gas from Alaska's North Slope to Alberta, Canada, and ultimately to the lower 48 States will be built in 2020, and that Alaska's natural gas production will increase by 1.6 trillion cubic feet as a result. The no Alaska pipeline case assumes that the pipeline will not be built, leading to higher prices in lower 48 natural gas markets, more lower 48 production and imports of natural gas, and lower consumption.

The largest impact on natural gas prices in the no Alaska pipeline case occurs when the pipeline reaches full capacity in 2022, two years after the pipeline begins operating in the reference case. In 2022, Henry Hub spot market prices for natural gas (in 2007 dollars) are higher by $0.63 per thousand cubic feet in the no Alaska pipeline case than in the reference case. After 2022 the price impact lessens gradually, to $0.13 per thousand cubic feet in 2030 (Figure 69). In 2026, total natural gas consumption is 0.8 trillion cubic feet lower in the no pipeline case than in the reference case, and consumption for electricity generation is 0.3 trillion cubic feet lower.

Higher natural gas prices and reduced supply in the no pipeline case lead to more unconventional production and LNG imports in the lower 48 States. Pipeline imports from Canada, which in the no pipeline case do not compete with Alaska natural gas in lower 48 markets, are 0.5 trillion cubic feet above the reference case level in 2028. LNG imports are only slightly higher in the no pipeline case, as a result of increased competition in world markets and the availability of domestic natural supplies at competitive prices.

U.S. Crude Oil Production Increases With Rising Oil Prices

Figure 70. Domestic crude oil production by source, 1990-2030 (million barrels per day)



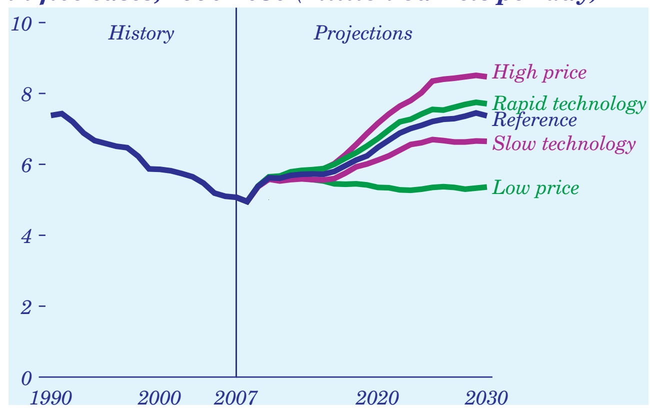
The long-term decline in total U.S. crude production has slowed over the past few years, as higher world oil prices have spurred drilling. In the projections, total U.S. domestic crude oil production, which has been falling for many years, begins to increase in 2009. Most of the near-term increase is from the deepwater offshore. Growth is limited after 2010, however, because newer discoveries are smaller, and capital expenditures rise as development moves into deeper waters.

A number of deepwater discoveries in the Gulf of Mexico have begun to ramp up production recently or are expected to begin production by the end of 2009. The largest include Shenzi, Atlantis, Blind Faith, and Thunder Horse. Expiration of the Congressional moratoria on the Eastern Gulf of Mexico, Atlantic, and Pacific regions of the OCS also allow crude oil production to increase in the Atlantic and Pacific OCS after 2014 and in the Eastern Gulf of Mexico OCS after 2025. Total offshore production increases at an average annual rate of 2.8 percent, from 1.4 million barrels per day in 2007 to 2.7 million barrels per day in 2030.

U.S. onshore crude oil production also increases throughout the projection, primarily as a result of increased application of CO_2-enhanced oil recovery techniques, exploitation of oil from the Bakken shale formation [*98*], and the startup of liquids production from oil shale, which is supported by favorable world oil prices and continued advances in oil shale extraction technology. Total onshore production of crude oil increases from 2.9 million barrels per day in 2007 to 4.1 million barrels per day in 2030 (Figure 70).

U.S. Oil Production Depends on Prices, Access, and Technology

Figure 71. Total U.S. crude oil production in five cases, 1990-2030 (million barrels per day)

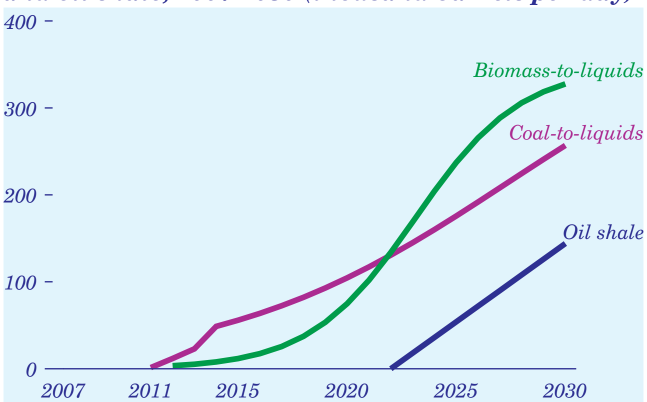


U.S. crude oil production is highly sensitive to world crude oil prices, because the remaining domestic resource base generally requires more costly secondary or tertiary recovery techniques, which are likely to be uneconomical when world oil prices are low. Even when prices are higher, however, high-cost projects typically involve long lead times from discovery to production, which limit their impact on total production levels. In the high oil price case, U.S. crude oil production in 2030 is 1.1 million barrels per day higher than in the reference case, mostly as a result of increased production from onshore CO_2-enhanced oil recovery projects and offshore deepwater projects. In the low oil price case, crude oil production in 2030 is 2.0 million barrels per day lower than in the reference case, primarily because of lower production from CO_2-enhanced recovery projects, and because fewer projects in the lower 48 offshore and Alaska's North Slope are economical when world oil prices are relatively low.

Both onshore and offshore production generally increase as technology advances reduce the costs of exploration and development. In the rapid technology case, U.S. crude oil production in 2030 is 0.3 million barrels per day higher than in the reference case, with most of the increase coming from resources in the lower 48 offshore. In the slow technology case, crude oil production in 2030 is 0.7 million barrels per day lower than in the reference case (Figure 71). Most of the difference between the 2030 production levels in the reference and slow technology cases results from lower levels of production from CO_2-enhanced oil recovery in the slow technology case.

BTL, CTL, and Oil Shale Production Grows With Technology Improvement

Figure 72. Liquids production from gasification and oil shale, 2007-2030 (thousand barrels per day)



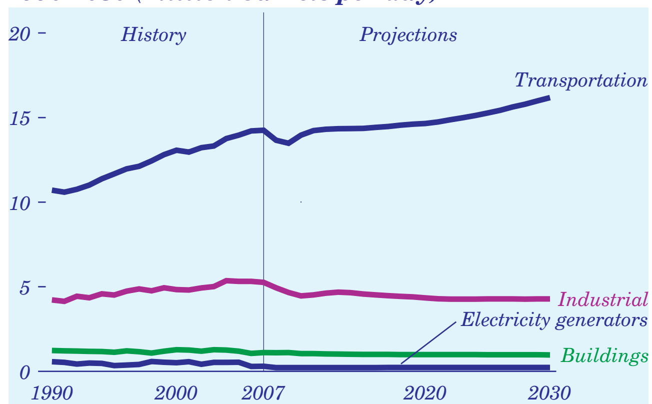
Production of liquid fuels from oil shale, coal, natural gas, and biomass becomes viable over time in the reference case as a result of continued technology improvements and rising oil prices. Growth in their production can be moderated, however, by rising capital costs and by the enactment of more stringent environmental regulations affecting water and land use—which increase production costs—and GHG emissions. Consequently, penetration rates vary for the different production processes.

BTL production begins in 2012 in the reference case and grows by an average of 29 percent per year through 2030 (Figure 72). CTL production begins in 2011 and grows by an average of 19 percent per year. The increase in CTL production would be larger if it were not constrained by the reference case assumption that growing concern about GHG emissions will limit investment in the carbon-intensive CTL technology.

Oil shale production begins later, in 2023, but increases rapidly, averaging 35 percent per year from 2023 to 2030. Research and development efforts are expected to provide the necessary technology improvements to yield commercial quantities of liquids from oil shale production that, over time, can be further increased in scale. Although no GTL production is expected before 2030 in the reference case, GTL production in Alaska begins in 2017 in the high oil price case and then grows by an average of 21 percent per year from 2017 to 2030.

Transportation Sector Dominates Liquid Fuels Consumption

Figure 73. Liquid fuels consumption by sector, 1990-2030 (million barrels per day)



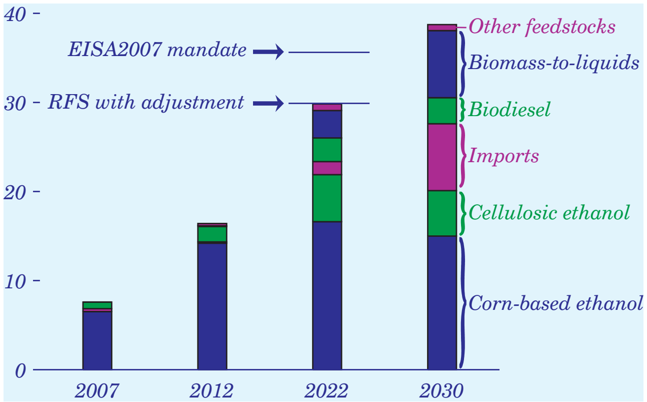
The transportation sector continues to dominate liquid fuels consumption in the projections (Figure 73), with large increases in the use of diesel fuel and biofuels. In the reference case, total consumption of petroleum-based motor gasoline in 2030, including E10 but excluding E85, is 1.3 million barrels per day below the 2007 total, whereas both consumption of diesel fuel and consumption of E85 increase, by about 1.5 million barrels per day each. Biofuel consumption grows with the EISA2007 mandates, and diesel fuel consumption expands as more light-duty diesel vehicles are produced by automotive manufacturers seeking to comply with new CAFE standards. Diesel fuel use for freight trucks also increases as industrial output expands.

In the other sectors, liquid fuels consumption declines through 2030. Industrial use of liquids drops by 19 percent, despite a 47-percent increase in industrial shipments. Much of the decline from 2007 to 2030 results from changes in the chemical industry, where there is a shift in the production mix, and energy efficiency improves. Liquid fuels consumption in the buildings sector continues to fall, as fewer buildings use oil for heating, and efficiency improves as older systems are replaced with more efficient equipment.

Liquid fuels consumption in the electric power sector declines as a result of slowing growth in demand for electricity from 2007 to 2030. With Federal and State efficiency standards minimizing the need for new generating capacity, little new oil-fired capacity is installed, and generation from older oil-fired capacity is offset by production from new capacity using coal, natural gas, nuclear, and renewable fuels.

EISA2007 RFS Mandate for 2022 Is Met in 2027

Figure 74. RFS credits earned in selected years, 2007-2030 (billion credits)



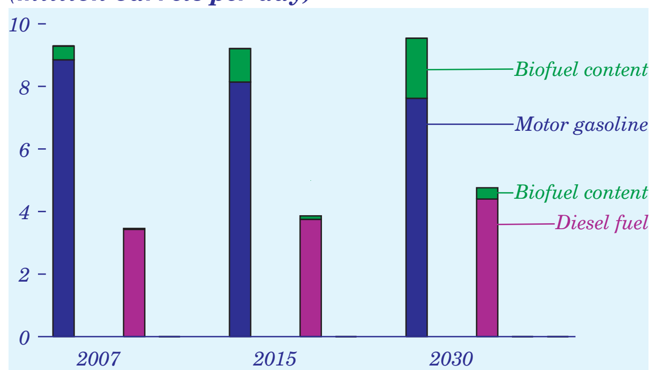
EISA2007 mandates a total RFS credit requirement of 36 billion gallons in 2022. Credits are equal to gallons produced, except for fatty acid methyl ester biodiesel and BTL diesel, which receive a 1.5-gallon credit for each gallon produced. The renewable fuels can be grouped into two categories: conventional biofuels (ethanol produced from corn starch) and advanced biofuels (including cellulosic ethanol, biodiesel, and BTL diesel). In total, 15 billion gallons of credits from conventional biofuels and 21 billion gallons from advanced biofuels are required in 2022.

In the *AEO2009* reference case, the credit requirement for conventional biofuels is met in 2022, but the requirement for advanced fuels is not. In that event, EISA2007 provides for both the application of waivers and modification of applicable credit volumes. The RFS mandates are achieved in 2027 in the reference case, and as BTL production grows, the overall target of 36 billion gallons is exceeded in 2030 (Figure 74).

Progress toward meeting the RFS is complicated by slowing growth in U.S. petroleum use through 2030. The push for more fuel-efficient automobiles, which slows the increase in motor gasoline consumption in the reference case, also slows progress toward meeting the RFS, because more efficient gasoline engines and growing penetration of hybrids reduce the demand for ethanol in gasoline fuel blends. A 10-percent limit on ethanol in gasoline for most of the current fleet of passenger vehicles delays further market penetration until more E85-compatible vehicles are in use and the market infrastructure for E85 and other biofuels is expanded to accommodate the distribution and sale of growing volumes.

Biofuels Displace Conventional Fuels in the Transportation Mix

Figure 75. Biofuel content of U.S. motor gasoline and diesel consumption, 2007, 2015, and 2030 (million barrels per day)



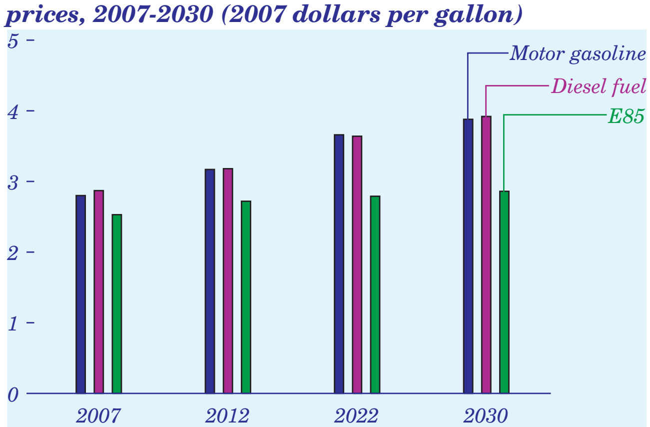
As a result of the RFS in EISA2007, CAFE standards, and higher liquid prices, biofuels in the form of ethanol and biodiesel displace a growing portion of the fossil fuel component of transportation fuel use in the reference case (Figure 75). With biofuels representing all the growth in motor fuel supply, there is virtually no growth in petroleum consumption through 2030, as demand for petroleum-based gasoline declines and demand for petroleum-based diesel grows modestly. The growing share for diesel fuel is similar to recent trends in Europe, where increases in diesel use have outpaced the growth in gasoline use for some time, causing European refineries to be reconfigured for more diesel production.

U.S. production of biofuels grows from less than 0.5 million barrels per day in 2007 to 2.3 million barrels per day in 2030. Ethanol production provides the largest share of that growth, as ethanol use for gasoline blending grows to more than 0.8 million barrels per day and ethanol consumption in E85 increases to 1.1 million barrels per day in 2030. Much of the growth in demand for E85 occurs after 2015, when the market for E10 blending is saturated. Although most of the ethanol consumed is produced domestically, net imports of ethanol also increase, to 0.5 million barrels per day in 2030.

To meet RFS and CAFE standards, the vehicle fleet changes dramatically in the reference case. In 2030, 60 percent of the new LDVs sold are E85, flex-fuel, conventional hybrid, or PHEVs.

Ethanol Prices Compete on a Btu Basis To Meet the EISA2007 RFS

Figure 76. Motor gasoline, diesel fuel, and E85 prices, 2007-2030 (2007 dollars per gallon)



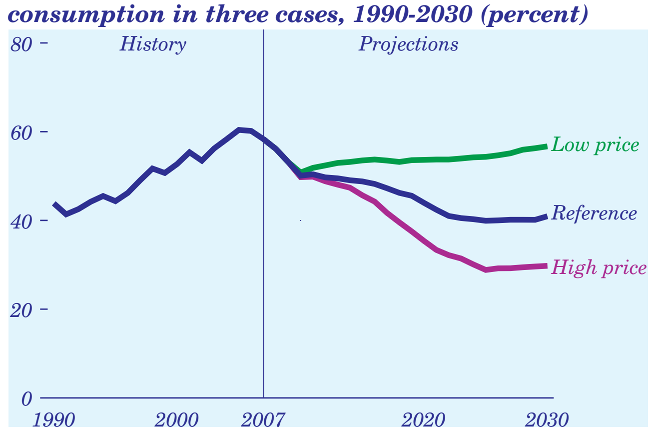
With crude oil prices rising in the reference case, prices for both gasoline and diesel fuel increase by an average of 1.4 percent per year, to about $4 per gallon (2007 dollars) in 2030 (Figure 76). The average increase in E85 prices is 0.5 percent per year over the same period, and the E85 price in 2030 is less than $3 per gallon. As a result, the difference between gasoline and E85 prices increases from roughly 30 cents per gallon in 2007 to more than a dollar per gallon in 2030.

In the reference case, ethanol is used initially as a blending component with gasoline, but the U.S. market for ethanol blending with gasoline to make E10 is near saturation by 2012. Meeting the EISA2007 RFS after 2012 therefore requires increased consumption of E85. To encourage the use of E85, its price (in terms of energy content) must be equivalent to or below the price of motor gasoline. E85 prices increase only moderately in the reference case, to $2.72 per gallon in 2012 and $2.79 in 2022, on the path to achieving the sales volume needed to meet the RFS mandate.

The increase in ethanol sales requires construction of a sufficient base of E85 fueling stations and distribution infrastructure to ensure the commercial viability of a growing fleet of E85 vehicles. *AEO2009* assumes that the average cost to modify an existing service station for E85 sales will be about $46,000. Assuming no intermediate ethanol blends, E85 prices must be subsidized by refiners and marketers through high prices for gasoline and diesel fuel in order to meet the mandated ethanol level in the RFS once the E10 market is saturated and E85 is the primary contributor.

Imports of Liquid Fuels Vary With World Oil Price Assumptions

Figure 77. Net import share of U.S. liquid fuels consumption in three cases, 1990-2030 (percent)

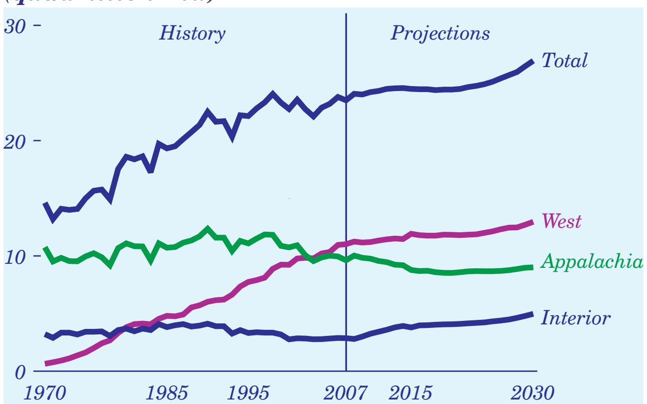


U.S. imports of liquid fuels, which grew steadily from the mid-1980s to 2005, decline sharply from 2007 to 2030 in the reference and low oil price cases, even as they continue to provide a major part of total U.S. liquids supply. Increasing use of biofuels, much of which are domestically produced, tighter CAFE standards, and higher energy prices moderate the growth in demand for liquids. A combination of higher prices and mandates leads to increased domestic production of oil and biofuels. In the reference case, there is essentially no growth in the use of liquid fuels from 2007 to 2030.

The net import share of U.S. liquid fuels consumption fell from 60 percent in 2005 to 58 percent in 2007. That trend continues in the reference case, with a net import share of 41 percent in 2030, and in the high oil price case, with a 30-percent share in 2030. In the low price case, the net import share falls in the near term before rising to 57 percent in 2030. With lower prices for liquid fuels, demand increases while domestic production decreases, and more imports are needed to meet demand. With higher prices, the need for imports is smaller but still substantial (Figure 77). Increased penetration of biofuels in the liquids market reduces the need for imports of crude oil and petroleum products in the high price case.

Total Coal Production Increases at a Slower Rate Than in the Past

Figure 78. Coal production by region, 1970-2030 (quadrillion Btu)



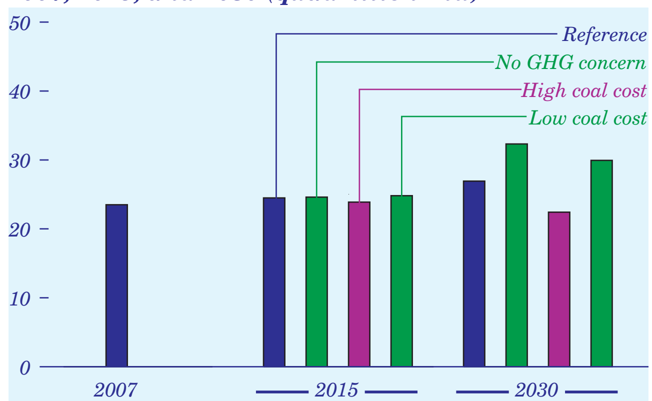
In the *AEO2009* reference case, increasing coal use for electricity generation at both new and existing plants and the startup of several CTL plants lead to modest growth in coal production, averaging 0.6 percent per year from 2007 to 2030—slightly less than the 0.9-percent average growth rate for U.S. coal production from 1980 to 2007.

Western coal production, which has grown steadily since 1970, continues to increase through 2030 (Figure 78), but at a much slower rate than in the past. Most of the additional output originates from mines located in Wyoming, Montana, and North Dakota. Roughly one-half of the West's additional coal production is used for fuel and feedstock at new CTL plants, and the remainder is used for electricity generation at existing and new coal-fired power plants.

Production of higher sulfur coal in the Interior region, which has trended downward since the early 1990s, rebounds as existing coal-fired power plants are retrofitted with flue gas desulfurization (FGD) equipment and new coal-fired capacity is added in the Southeast. Much of the additional output from the Interior region originates from mines tapping into the extensive reserves of mid- and high-sulfur bituminous coal in Illinois, Indiana, and western Kentucky. In Appalachia, total production declines slightly from current levels as output shifts from the extensively mined, higher cost reserves of Central Appalachia to lower cost supplies from the Interior region, South America, and the northern part of the Appalachian basin.

Long-Term Production Outlook Varies Considerably Across Cases

Figure 79. U.S. coal production in four cases, 2007, 2015, and 2030 (quadrillion Btu)



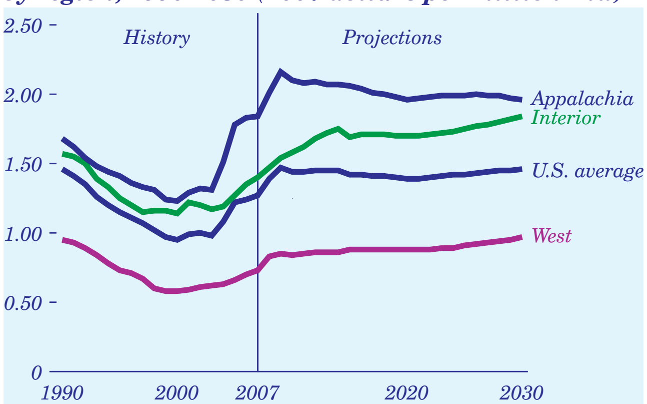
U.S. coal production varies across the *AEO2009* cases, in particular when different policies are assumed with regard to GHG emissions. Different assumptions about the costs of producing and transporting coal also lead to substantial variations in the outlook for coal production.

The no GHG concern case illustrates the potential for a sizable increase in coal production. In the absence of a risk premium for carbon-intensive technologies, more new coal-fired power plants and CTL plants are built than in the reference case. In 2030, coal production in the no GHG concern case is 20 percent above the reference case projection (Figure 79). In contrast, if policies to reduce or limit GHG emissions were enacted in the future, they could result in significant reductions in coal use at existing power plants and limit the amount of new coal-fired capacity built in the future. The impact on coal use would depend on details of the policies, such as the allocation of emissions allowances, the inclusion of a "safety valve" or other mechanism to limit the price of allowances (and its level), and the inclusion of provisions to encourage the use of particular fuels or technologies.

In the high coal cost case, higher costs for coal mining and transportation lead to some switching from coal to natural gas and nuclear in the electric power sector, along with slightly slower growth in electricity demand. In the low coal cost case, the trends are in the opposite direction. As a result, coal production in 2030 is 17 percent lower in the high coal cost case, and 11 percent higher in the low coal cost case, than in the reference case.

Minemouth Coal Prices in the Western and Interior Regions Continue Rising

Figure 80. Average minemouth coal prices by region, 1990-2030 (2007 dollars per million Btu)



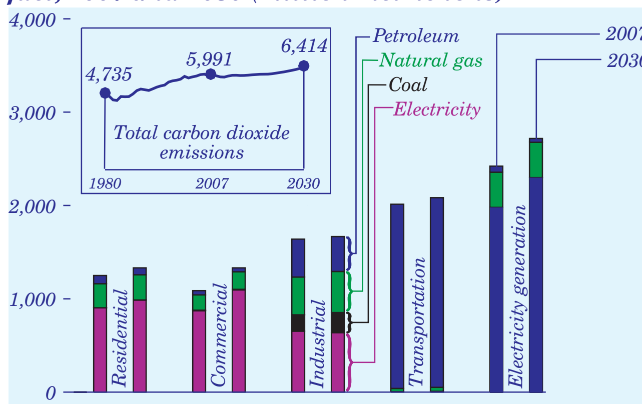
In the near term, rising prices for the mining equipment, parts and supplies, and fuel used at coal mines lead to higher minemouth prices for coal in all regions (Figure 80). In the Appalachian region, a resurgence in production of high-value coal for export adds to the early price surge. In the longer term, limited improvement in coal mining productivity and increased production from the Interior and Western supply regions result in higher minemouth prices in both regions, increasing on average by 1.2 percent per year from 2007 to 2030. After peaking in 2009, the average minemouth price for Appalachian coal declines by 0.5 percent per year through 2030, as a result of falling demand and a shift to lower cost production in the northern part of the basin.

Reflecting regional trends, the U.S. average minemouth price of coal rises significantly between 2007 and 2009, from $1.27 to $1.47 per million Btu. After the initial run-up, however, prices level off and then fall slightly through 2020, as mine capacity utilization declines and production shifts away from the higher cost mines of Central Appalachia.

In the reference case, the assumed risk premium for carbon-intensive technologies dampens investment in new coal-fired power plants; however, a growing need for additional generating capacity of all types results in the construction of 28 gigawatts of new coal-fired capacity after 2020. The combination of new investment in mining capacity to meet demand growth and a continued low rate of productivity improvement leads to an increase in the average minemouth price of coal, from $1.39 per million Btu in 2020 to $1.46 in 2030.

Rate of Increase in Carbon Dioxide Emissions Slows in the Projections

Figure 81. Carbon dioxide emissions by sector and fuel, 2007 and 2030 (million metric tons)



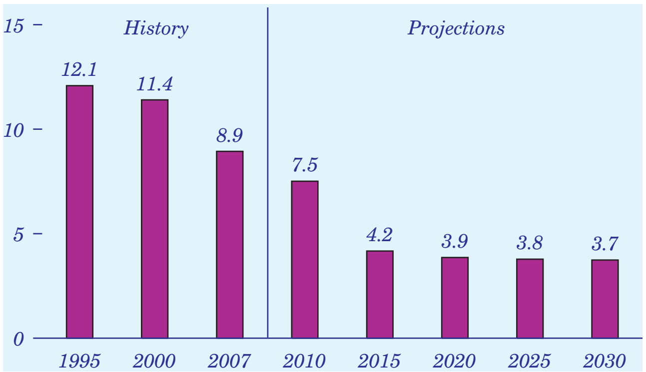
Even with rising energy prices, growth in energy use leads to increasing U.S. CO_2 emissions in the absence of explicit policies to reduce GHG emissions; however, the appliance efficiency, CAFE, and tax policies enacted in 2007 and 2008, slow the growth of U.S. energy demand, and as a result, energy-related CO_2 emissions in the *AEO2009* reference case grow by 0.3 percent per year from 2007 to 2030, as compared with 0.8 percent per year from 1980 to 2007. In 2030, energy-related CO_2 emissions total 6,414 million metric tons, about 7 percent higher than in 2007.

Slower emissions growth is also, in part, a result of the declining share of electricity generation that comes from fossil fuels—primarily, coal and natural gas—and the growing renewable share, which increases from 8 percent in 2007 to 14 percent in 2030. As a result, while electricity generation increases by 0.9 percent per year, CO_2 emissions from electricity generation increase by only 0.5 percent per year. The largest share of U.S. CO_2 emissions comes from electricity generation (Figure 81).

The U.S. economy becomes less carbon intensive as CO_2 emissions per dollar of GDP decline by 39 percent and emissions per capita decline by 14 percent over the projection. Increased demand for energy services is offset in part by shifts toward less energy-intensive industries, efficiency improvements, and increased use of renewables and other less carbon-intensive energy fuels. More rapid improvements in technologies that emit less CO_2, new CO_2 mitigation requirements, or more rapid adoption of voluntary CO_2 emissions reduction programs could result in lower CO_2 emissions levels than are projected here.

Without Clean Air Interstate Rule, Sulfur Dioxide Emissions Still Decline

Figure 82. Sulfur dioxide emissions from electricity generation, 1995-2030 (million short tons)



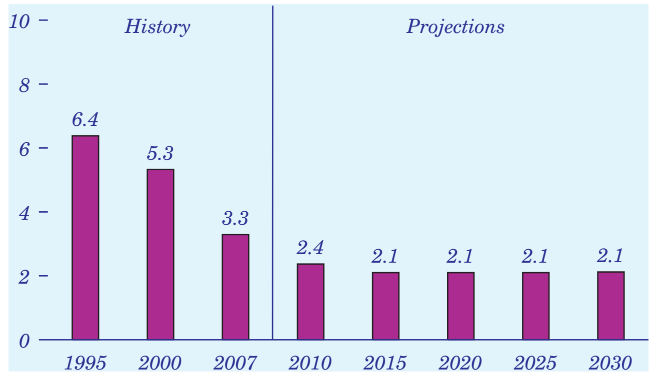
CAIR is not included in the *AEO2009* reference case, because in July 2008 the U.S. Court of Appeals vacated and remanded the rule, which included a cap-and-trade system to reduce SO_2 emissions. The same court has since temporarily reinstated CAIR, but that ruling was not issued until December 2008, and the *AEO2009* projections are based on laws and regulations in effect as of November 2008.

The reference case assumes that the States will mandate SO_2 emissions controls, such as FGD or the use of low-sulfur coal, to meet emissions goals even without CAIR. As a result, SO_2 emissions from electric power plants in 2030 in the reference case are more than 50 percent below their 2007 level (Figure 82), similar to projections in previous *AEO*s that assumed CAIR would be in effect. SO_2 emissions fall even though coal-fired generating capacity expands, as more than 114 gigawatts of existing coal-fired capacity is retrofitted with FGD equipment in the reference case through 2030. Because SO_2 allowance trading under CAIR is not included in *AEO2009*, there is no SO_2 allowance trading. With the reinstatement of CAIR, allowance trading and allowance prices will be included in future analyses.

The amount of new coal-fired capacity added in the reference case has little impact on SO_2 emissions, because it is assumed that all new capacity will include extensive emissions control systems. In contrast, implementation of a GHG emissions control policy could lower SO_2 and other emissions significantly by reducing generation from older, less efficient coal-fired power plants without FGD equipment.

Nitrogen Oxide Emissions Also Decline in the Reference Case

Figure 83. Nitrogen oxide emissions from electricity generation, 1995-2030 (million short tons)



Even without the CAIR mandates, States will need to reduce NO_x emission in order to meet the CAA standards for ground-level ozone. The *AEO2009* reference case assumes that individual States will enact their own mandates for NO_x emissions controls, which will meet the targets originally outlined in CAIR. Because it is assumed that the States will not use a cap-and-trade program, there is no allowance price for NO_x.

In the reference case, NO_x emissions in 2030 are about 35 percent below the 2007 level (Figure 83). Just as in the case of SO_2 emissions, the reduction occurs even as more electricity is generated at coal-fired power plants. The reference case assumes that the States will require older coal-fired plants to be retrofitted with selective catalytic control (SCR) equipment, and that new plants will be required to have pollution control equipment that meets the CAA New Source Performance Standards. Through 2030, an estimated 95 gigawatts of existing coal-fired capacity is retrofitted with SCR equipment in the reference case.

In the future, enactment of policies to limit or reduce GHG emissions could affect NO_x emissions from electricity generation. Controlling GHG emissions would require changes in the utilization of existing coal-fired capacity that would also reduce emissions of NO_x.

Endnotes for Market Trends

94. The energy-intensive manufacturing sectors include food, paper, bulk chemicals, petroleum refining, glass, cement, steel, and aluminum.
95. S.C. Davis and S.W. Diegel, *Transportation Energy Data Book: Edition 25*, ORNL-6974 (Oak Ridge, TN, May 2006), Chapter 4, "Light Vehicles and Characteristics," web site http://cta.ornl.gov/data/chapter4.shtml.
96. Unless otherwise noted, the term "capacity" in the discussion of electricity generation indicates utility, nonutility, and CHP capacity. Costs reflect the average of regional costs, except that a representative region is used to estimate costs for wind plants.
97. Customer-sited PV does not include off-grid PV. Based on 1989-2006 annual PV shipments, EIA estimates that as much as 210 megawatts of remote PV applications for electricity generation (off-grid power systems) were in service in 2006, plus an additional 526 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384 (2007) (Washington, DC, June 2008), Table 10.8, "Photovoltaic Cell and Module Shipments by End Use and Market Sector, 1989-2006," web site www.eia.doe.gov/emeu/aer/renew.html. The approach used to develop the table, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It overestimates the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed in earlier years are retired from service or abandoned.
98. Energy Information Administration, "The Bakken Formation Helps Increase U.S. Proved Reserves of Oil," *This Week in Petroleum* (March 4, 2009), web site http://tonto.eia.doe.gov/oog/info/twip/twiparch/090304/twipprint.html.

Comparison With Other Projections

Comparison with Other Projections

Only IHS Global Insight (IHSGI) produces a comprehensive energy projection with a time horizon similar to that of *AEO2009*. Other organizations, however, address one or more aspects of the U.S. energy market. The most recent projection from IHSGI, as well as others that concentrate on economic growth, international oil prices, energy consumption, electricity, natural gas, petroleum, and coal, are compared here with the *AEO2009* projections.

Economic Growth

Projections of the average annual real GDP growth rate for the United States from 2007 through 2010 range from 0.2 percent to 3.1 percent (Table 15). Real GDP grows at an annual rate of 0.6 percent in the *AEO2009* reference case over the period, significantly lower than the projections made by the Office of Management and Budget (OMB), the Bureau of Labor Statistics (BLS), and the Social Security Administration (SSA)—although not all of those projections have been updated to take account of the current economic downturn. The *AEO2009* projection is slightly lower than the projection by IHSGI and slightly higher than the projection by the Interindustry Forecasting Project at the University of Maryland (INFORUM). In March 2009, the consensus Blue Chip projection was for 2.2-percent average annual growth from 2007 to 2010.

The range of GDP growth rates is narrower for the period from 2010 to 2015, with projections ranging from 2.1 to 3.8 percent per year. The average annual GDP growth of 3.2 percent in the *AEO2009* reference case from 2010 to 2015 is mid-range, with the Congressional Budget Office (CBO) projecting a stronger recovery from the recession. CBO projects average annual GDP growth of 3.8 percent, IHSGI projects growth of 3.1 percent, and the INFORUM, SSA, and International Energy Agency (IEA) projections all project growth that is below the *AEO2009* reference case projection.

There are few public or private projections of GDP growth for the United States that extend to 2030. The *AEO2009* reference case projects 2.5-percent average annual GDP growth from 2007 to 2030, consistent with the trend in expected labor force and productivity growth. IHSGI projects GDP growth from 2007 to 2030 at 2.4 percent, and INFORUM expects lower GDP growth at 2.2 percent over the same period. INFORUM also projects lower growth in productivity and the labor force.

Table 15. Projections of annual average economic growth rates, 2007-2030

Projection	Average annual percentage growth rates			
	2007-2010	2010-2015	2015-2020	2020-2030
AEO2008 (reference case)	2.5	2.7	2.4	2.4
AEO2009 (reference case)	0.6	3.2	2.6	2.6
IHSGI (November 2008)	0.7	3.1	2.8	2.5
OMB (June 2008)	2.9	2.9	NA	NA
CBO (January 2009)	0.2	3.8	2.3	NA
INFORUM (December 2008)	0.4	2.8	2.3	2.3
SSA (May 2008)	2.6	2.4	2.3	2.1
BLS (November 2007)	3.1	2.4	NA	NA
IEA (November 2008)	NA	2.1	NA	2.1
Blue Chip Consensus (March 2009)	2.2	2.8	2.7	NA

NA = not available.

World Oil Prices

Comparisons of the *AEO2009* cases with other oil price projections are shown in Table 16. In the *AEO2009* reference case, world oil prices rise from current levels to approximately $80 per barrel in 2010 and $110 per barrel in 2015. After 2015, prices increase to $130 per barrel in 2030. This price trend is higher than shown in the *AEO2008* reference case and, generally, more consistent with the *AEO2008* high oil price case.

Market volatility and different assumptions about the future of the world economy are reflected in the range of price projections for both the short term and the long term. The projections trend in different directions, with one group, the Institute of Energy Economics and the Rational Use of Energy at the University of Stuttgart (IER), showing prices stabilizing at around $70 per barrel by 2020 and remaining relatively constant through 2030 and another group, Energy Ventures Analysis, Inc. (EVA), showing prices rising steadily over the entire course of the projection period. Excluding the *AEO2009* reference case, the other projections range from $47 per barrel

Table 16. Projections of world oil prices, 2010-2030 (2007 dollars per barrel)

Projection	2010	2015	2020	2025	2030
AEO2008 (reference case)	75.97	61.41	61.26	66.17	72.29
AEO2008 (high price case)	81.08	92.77	104.74	112.10	121.75
AEO2009 (reference case)	80.16	110.49	115.45	121.94	130.43
DB	47.43	72.20	66.09	68.27	70.31
IHSGI	101.99	97.60	75.18	71.33	68.14
IEA (reference)	100.00	100.00	110.00	116.00	122.00
IER	65.24	67.03	70.21	72.37	74.61
EVA	57.09	74.61	95.33	105.25	116.21
SEER	54.82	98.40	89.88	82.10	75.00

to $102 per barrel in 2010, a span of $55 per barrel, and from $68 per barrel to $122 per barrel in 2030, a span of $54 per barrel. The wide range of the projections reflects the recent volatility of crude oil prices and the uncertainty inherent in the projections. The range of the other projections is encompassed in the range of the *AEO2009* low and high oil price cases, from $50 per barrel to $200 per barrel in 2030.

The world oil price measures are, by and large, comparable across projections. EIA reports the price of imported low-sulfur, light crude oil, approximately the same as the WTI prices that are widely cited as a proxy for world oil prices in the trade press. The only series that does not report projections in WTI terms is IEA's *World Energy Outlook 2008*, where prices are expressed as the IEA crude oil import price.

Total Energy Consumption

Both the *AEO2009* reference case and IHSGI projections show total energy consumption growing by 0.5 percent per year from 2007 to 2030. Given different totals for 2007, total energy consumption in 2030 in the IHSGI projection is about 1 quadrillion Btu lower than in the reference case. Growth rates by sector, however, differ between the two sets of projections (Table 17).

As shown in Table 16, energy prices in 2030 are higher in *AEO2009* than in the IHSGI projection. IHSGI's world oil price track is closer to the *AEO2009* low oil price case than the reference case. IHSGI's natural gas, coal, and electricity prices all are lower than those in the *AEO2009* reference case, but by a smaller percentage than the difference between the world oil price projections. As a result, IHSGI projects stronger growth in petroleum consumption, a key factor in its higher projections for energy consumption in the residential and industrial sectors. The *AEO2009* reference case includes stronger growth in the commercial and transportation sectors than the IHSGI projection.

In the residential sector, natural gas and electricity use in the IHSGI projection both grow significantly faster than in the *AEO2009* reference case. Factors slowing growth in the *AEO2009* reference case include increased lighting efficiency, a switch to a 10-year average from a 30-year average for heating and cooling degree-days, and a more detailed breakout for televisions, personal computers, and related equipment that better accounts for efficiency changes. In both projections, total housing stock grows by about 1.0 percent per year from 2007 to 2030.

The commercial sector is the least reliant on liquid fuels among the end-use sectors, and the difference in world oil prices between IHSGI and the *AEO2009* has the least impact on projections for commercial energy use. In the *AEO2009* reference case, commercial energy demand is driven by growth in commercial floorspace (divided into 11 building types), as well as by weather, population, and disposable income. Total commercial floorspace grows by 1.3 percent per year in the reference case. IHSGI cites commercial energy use per employee, which grows by 1.0 percent per year, about the same as in *AEO2009*. Consumption growth for both natural gas and electricity is higher in *AEO2009*, despite slightly higher prices. One aspect that could account for this difference is that IHSGI projects a population growth rate slightly below 0.8 percent per year from 2007 to 2030, as compared with 0.9 percent per year in the *AEO2009* reference case. For the industrial sector, IHSGI expects lower energy prices and more rapid growth in output, leading to more rapid increases in consumption of petroleum, natural gas, and electricity, than are projected in *AEO2009*.

Table 17. Projections of energy consumption by sector, 2007 and 2030 (quadrillion Btu)

	2007		2030		Average annual percentage growth, 2007-2030	
Sector	**AEO2009**	**IHSGI**	**AEO2009**	**IHSGI**	**AEO2009**	**IHSGI**
Residential	11.4	10.9	12.4	13.0	0.4	0.8
Commercial	8.5	8.4	10.6	9.9	1.0	0.7
Industrial	25.3	23.0	26.3	25.6	0.2	0.5
Transportation	28.8	28.5	31.9	30.0	0.4	0.2
Electric power	40.7	42.1	48.0	49.9	0.7	0.7
Less: electricity losses	-12.8	-12.8	-15.7	-16.1	—	—
Total primary energy	**101.9**	**100.1**	**113.6**	**112.3**	**0.5**	**0.5**

More than 97 percent of the energy consumed in the transportation sector in 2007 came from liquid fuels. Despite lower world oil prices in the IHSGI projection, the *AEO2009* reference case projects more rapid growth in transportation energy consumption. In both the *AEO2009* and IHSGI projections, an increase in diesel fuel use is offset by a decrease in motor gasoline use; however, the offset is more than 1 quadrillion Btu larger in the IHSGI projection. A more rapid increase in jet fuel consumption is projected by IHSGI, in line with its lower fuel prices.

Electricity

Table 18 provides a summary of the results from the *AEO2009* cases and compares them with other projections. For 2015, electricity sales range from a low of 3,960 billion kilowatthours in the *AEO2009* reference case to a high of 4,475 billion kilowatthours in the projection from IER, which also shows higher sales in the commercial and residential sectors and much higher growth in industrial sales than the *AEO2009* reference case. For 2030, both IHSGI and IER have higher projections for total electricity sales in 2030 than the 4,609 billion kilowatthours in the *AEO2009* reference case. IHSGI and IER also project higher residential and industrial sales in 2030 than the *AEO2009* reference case. IER projects commercial sales that are higher than both IHSGI and the *AEO2009* reference case.

The *AEO2009* reference case shows declining real electricity prices after 2009 and then rising prices at the end of the period because of increases in the cost of fuels used for generation and increases in capital expenditures for construction of new capacity. The higher fossil fuel prices and capital expenditures in the *AEO2009* reference case result in an increase in the average electricity price from 9.1 cents per kilowatthour in 2015 to 10.4 cents per kilowatthour in 2030. IER and IHSGI show declining electricity prices between 2015 and 2030. In contrast, EVA shows higher prices than the other projections, with substantial increases between 2015 and 2030.

Total generation and imports of electricity in 2015 are lower in the EVA projections than in the *AEO2009* reference case, IHSGI, and IER projections. U.S. electricity generation in the IER projection (which excludes imports of electricity) is higher than in the other projections. Requirements for generating capacity are based on growth in electricity sales and the need to replace existing units that are uneconomical or are being retired for other reasons. Consistent with its projections of electricity sales, IER shows higher growth in generating capacity through 2015 than in the other projections.

Although the projections for coal-fired capacity in 2030 are similar (with EVA being somewhat lower than the others), there are significant differences in other capacity types. IHSGI and IER project similar levels of oil- and natural-gas-fired capacity, and both are significantly lower than projected in the *AEO2009* reference case. The EVA and IER projections for nuclear capacity are also much higher than the *AEO2009* and IHSGI projections. Nuclear capacity in 2030 is 113 gigawatts in *AEO2009* and 119 gigawatts in the IHSGI projections, as a result of the incentives included in EPACT2005. EVA and IER project substantially more aggressive nuclear growth, with total nuclear capacity at 166 and 154 gigawatts, respectively, in 2030. The *AEO2009* reference case includes 3.4 gigawatts of uprates for nuclear capacity and 4.4 gigawatts of nuclear plant retirements by 2030 as their operating licenses expire. The 2030 projections for renewable capacity also differ widely among the projections, from EVA's 128 gigawatts to IER's 312 gigawatts.

Environmental regulations are an important factor in the selection of technologies for electricity generation. The *AEO2009* reference case excludes the impact of the EPA's CAIR and CAMR regulations, and because only current laws and regulations as of November 2008 are included, it does not assume any tax on CO_2 emissions. Restrictions on CO_2 emissions could change the mix of technologies used to generate electricity.

Natural Gas

In the *AEO2009* reference case, total natural gas consumption declines in the short run (2008-2011), begins rising in 2014, peaks in 2025, then declines from 2025 to 2030 as consumption for electricity generation falls (Table 19). In the projections from other organizations, IHSGI, EVA, and Altos show steady increases in natural gas consumption (although the Altos projection includes an early decline, similar to that in the *AEO2009* reference case). EVA projects the highest level of consumption in 2030 (29.4 trillion cubic feet), followed by Altos (28.1 trillion cubic feet). In contrast, Deutsche Bank AG (DB), IER, and Strategic Energy and Economic Research, Inc. (SEER) show a peak in consumption around 2015 and a

Table 18. Comparison of electricity projections, 2015 and 2030 (billion kilowatthours, except where noted)

Projection	2007	AEO2009 reference case	Other projections		
			IHSGI	EVA	IER
		2015			
Average end-use price (2007 cents per kilowatthour)	**9.1**	**9.1**	**9.9**	**10.7**	**NA**
Residential	10.6	10.8	11.4	NA	9.6
Commercial	9.6	9.3	10.4	NA	9.6
Industrial	6.4	6.3	6.9	NA	7.4
Total generation plus imports	**4,190**	**4,398**	**4,589**	**4,174**	**4,696**
Coal	2,021	2,121	2,139	1,975	NA
Oil	66	57	54	58	NA
Natural gas [a]	892	815	1,004	889	NA
Nuclear	806	831	838	840	NA
Hydroelectric/other [b]	374	555	537	420	NA
Net imports	31	17	17	21	NA
Electricity sales	**3,747**	**3,960**	**4,138**	**NA**	**4,475**
Residential	1,392	1,423	1,559	NA	1,567
Commercial/other [c]	1,349	1,513	1,508	NA	1,649
Industrial	1,006	1,025	1,071	NA	1,259
Capability, including CHP (gigawatts) [d]	**996**	**1,050**	**1,030**	**1,084**	**1,117**
Coal	315	331	323	331	287
Oil and natural gas	448	458	441	488	510
Nuclear	101	104	105	105	111
Hydroelectric/other	131	157	160	115	208
		2030			
Average end-use price (2007 cents per kilowatthour)	**9.1**	**10.4**	**9.4**	**12.3**	**NA**
Residential	10.6	12.2	10.8	NA	8.6
Commercial	9.6	10.6	10.0	NA	8.6
Industrial	6.4	7.4	6.4	NA	6.5
Total generation plus imports	**4,190**	**5,181**	**5,229**	**4,871**	**5,335**
Coal	2,021	2,415	2,356	2,006	NA
Oil	66	60	40	46	NA
Natural gas [a]	892	1,012	1,035	968	NA
Nuclear	806	907	921	1,324	NA
Hydroelectric/other [b]	374	758	864	535	NA
Net imports	31	28	14	19	NA
Electricity sales	**3,747**	**4,609**	**4,717**	**NA**	**5,064**
Residential	1,392	1,667	1,829	NA	1,891
Commercial/other [c]	1,349	1,865	1,735	NA	1,963
Industrial	1,006	1,077	1,152	NA	1,210
Capability, including CHP (gigawatts) [d]	**996**	**1,227**	**1,102**	**1,171**	**1,224**
Coal	315	360	348	332	349
Oil and natural gas	448	563	403	501	409
Nuclear	101	113	119	166	154
Hydroelectric/other	131	191	232	128	312

[a]Includes supplemental gaseous fuels. For EVA, represents total oil and natural gas. [b]"Other" includes conventional hydroelectric, pumped storage, geothermal, wood, wood waste, municipal waste, other biomass, solar and wind power, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, petroleum coke, and miscellaneous technologies. [c]"Other" includes sales of electricity to government, railways, and street lighting authorities. [d]EIA capacity is net summer capability, including combined heat and power plants. IHSGI capacity is nameplate, excluding cogeneration plants.

CHP = combined heat and power. NA = not available.

Sources: ***2007 and AEO2009:*** AEO2009 National Energy Modeling System, run AEO2009.D120908A. **IHSGI:** IHS Global Insight, Inc., *Global Petroleum Outlook, Fall 2008* (Lexington, MA, November 2008). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (August 2008). **IER:** Institute of Energy Economics and the Rational Use of Energy at the University of Stuttgart, TIAM Global Energy System Model (November 2008).

steady decline thereafter. IER projects the lowest level of consumption in 2030 (21.4 trillion cubic feet), followed by DB (23.8 trillion cubic feet).

There are some notable variations across the projections for natural gas consumption by sector. For the residential sector, only Altos shows a decline in consumption in the later years of the projection, with residential natural gas use in 2030 lower than in 2007. DB projects the greatest increase in residential natural gas consumption, with 2030 consumption 1.3 trillion cubic feet higher than in 2007. *AEO2009* shows the smallest increase, with 2030 consumption 0.2 trillion cubic feet higher than in 2007.

For natural gas use in the commercial sector there is significant variation among the projections. Most show consumption increasing over the projection period, with the notable exceptions of DB and IER. As a result, there is a significant range among the projections for 2030, with Altos showing an increase of 0.7 trillion cubic feet from 2007 (slightly higher than the

Table 19. Comparison of natural gas projections, 2015, 2025, and 2030 (trillion cubic feet, except where noted)

Projection	2007	AEO2009 reference case	Other projections					
			IHSGI	EVA	DB	IER	SEER	Altos
					2015			
Dry gas production [a]	**19.30**	**20.31**	**21.93**	**20.35**	**21.96**	**15.64**	**22.13**	**20.40**
Net imports	**3.79**	**2.36**	**3.01**	**3.74**	**5.02**	**10.75**	**3.55**	**5.54**
Pipeline	3.06	1.11	1.41	1.98	2.83	5.01	1.80	1.34
LNG	0.73	1.25	1.60	1.76	2.19	5.74	1.75	4.20
Consumption	**23.05**	**22.77**	**24.92**	**25.56**	**26.21**	**26.39**	**25.68**	**22.55** [b]
Residential	4.72	4.87	5.08	5.07	5.22	5.28	4.91	4.22
Commercial	3.01	3.16	3.14	3.08	3.34	2.28	3.27	2.87
Industrial [c]	6.63	6.80	6.97	7.38	7.26	5.35	6.58	6.30 [d]
Electricity generators [e]	6.87	6.04	7.63	8.05	8.38	8.83	9.03	9.15
Other [f]	1.81	1.90	2.11	1.98	2.01	4.65	1.89	NA
Lower 48 wellhead price (2007 dollars per thousand cubic feet) [g]								
	6.39	**6.27**	**8.73**	**6.16**	**7.80**	7.38	**6.85**	**7.47**
End-use prices (2007 dollars per thousand cubic feet)								
Residential	13.05	12.32	14.49	NA	NA	12.58	12.76	NA
Commercial	11.30	10.86	13.06	NA	NA	11.28	11.23	NA
Industrial [h]	7.73	7.21	10.67	NA	NA	9.86	8.15	NA
Electricity generators	7.22	6.90	9.40	NA	NA	8.16	7.74	NA
					2025			
Dry gas production [a]	**19.30**	**23.22**	**22.07**	**18.75**	**19.75**	**14.51**	**21.32**	**18.80**
Net imports	**3.79**	**1.35**	**3.51**	**8.50**	**5.36**	**7.76**	**3.24**	**9.50**
Pipeline	3.06	0.15	0.91	2.91	1.83	2.02	0.56	0.30
LNG	0.73	1.20	2.60	5.58	3.53	5.74	2.68	9.20
Consumption	**23.05**	**24.67**	**25.56**	**27.41**	**24.83**	**22.27**	**24.56**	**26.06** [b]
Residential	4.72	4.99	5.31	5.31	5.76	5.40	4.95	4.10
Commercial	3.01	3.36	3.18	3.14	2.73	2.23	3.50	3.09
Industrial [c]	6.63	6.76	7.36	8.16	5.92	4.28	6.64	6.60 [d]
Electricity generators [e]	6.87	7.38	7.55	8.69	8.59	5.47	7.49	12.27
Other [f]	1.81	2.19	2.17	2.11	1.82	4.88	1.99	NA
Lower 48 wellhead price (2007 dollars per thousand cubic feet) [g]								
	6.39	**7.33**	**7.47**	**7.20**	**9.45**	**8.17**	**7.25**	**9.21**
End-use prices (2007 dollars per thousand cubic feet)								
Residential	13.05	13.43	13.02	NA	NA	13.37	13.35	NA
Commercial	11.30	12.07	11.63	NA	NA	12.07	11.56	NA
Industrial [h]	7.73	8.22	9.35	NA	NA	10.77	8.55	NA
Electricity generators	7.22	7.95	8.10	NA	NA	8.95	8.06	NA

NA = not available. See notes and sources at end of table.

AEO2009 projection) and DB showing a decrease of 0.7 trillion cubic feet.

The range of projections for natural gas consumption in the industrial sector is similar to that for the commercial sector. Only DB and IER show declines from 2007 to 2030. Whereas EVA shows an increase of 2.0 trillion cubic feet, IER shows a decrease of 3.2 trillion cubic feet.

Natural gas consumption in the electricity generation sector grows steadily from 2007 to 2015 in all the projections, with the exception of a projected decline in the *AEO2009* reference case from 6.9 trillion cubic feet in 2007 to 6.0 trillion cubic feet in 2015. IHSGI, EVA, DB, and Altos show greater reliance on natural gas for electricity generation than the *AEO2009* projection. The largest increase from 2007 to 2030 is projected by Altos (5.3 trillion cubic feet), followed by EVA (3.1 trillion cubic feet). *AEO2009* shows an initial decline, followed by an increase and then another decline in the later years of the projection, but is within the range of the other projections.

Sources of natural gas supply also vary among the projections. In all the projections, U.S. pipeline imports in 2030 are lower than in 2007, although IER projects an initial increase in net pipeline imports from 2007 to 2015. The size of the decline in pipeline imports is similar in the *AEO2009*, IHSGI, SEER, and Altos projections, whereas DB shows a smaller but steady decrease. The IER projection for 2030 is similar to the DB projection, although there are differences between the two in the years from 2007 to 2025. EVA shows an initial decline in natural gas pipeline imports, followed by a recovery and a

Table 19. Comparison of natural gas projections, 2015, 2025, and 2030 (continued)
(trillion cubic feet, except where noted)

Projection	2007	AEO2009 reference case	Other projections					
			IHSGI	EVA	DB	IER	SEER	Altos
					2030			
Dry gas production [a]	**19.30**	**23.60**	**22.33**	**18.49**	**18.70**	**13.76**	**20.44**	**17.70**
Net imports	**3.79**	**0.66**	**3.56**	**9.17**	**5.39**	7.64	**3.74**	**11.01**
Pipeline	3.06	-0.18	0.51	2.49	1.83	1.97	0.32	0.01
LNG	0.73	0.85	3.05	6.68	3.56	5.68	3.42	11.00
Consumption	**23.05**	**24.36**	**25.87**	**29.41**	**23.81**	**21.41**	**24.18**	**28.13 [b]**
Residential	4.72	4.93	5.39	5.43	6.06	5.60	4.92	4.63
Commercial	3.01	3.44	3.23	3.17	2.35	2.50	3.66	3.69
Industrial [c]	6.63	6.85	7.32	8.60	5.09	3.42	6.62	7.61 [d]
Electricity generators [e]	6.87	6.93	7.75	9.94	8.59	4.36	6.98	12.20
Other [f]	1.81	2.21	2.19	2.27	1.73	5.52	1.99	NA
Lower 48 wellhead price (2007 dollars per thousand cubic feet) [g]								
	6.39	**8.40**	**7.61**	**7.78**	**9.94**	**8.88**	**7.28**	**10.13**
End-use prices (2007 dollars per thousand cubic feet)								
Residential	13.05	14.71	13.06	NA	NA	14.08	13.48	NA
Commercial	11.30	13.32	11.70	NA	NA	12.78	11.56	NA
Industrial [h]	7.73	9.33	9.47	NA	NA	11.48	8.57	NA
Electricity generators	7.22	8.94	8.23	NA	NA	9.66	8.31	NA

NA = not available.

[a]Does not include supplemental fuels. [b]Does not include natural gas use as fuel for lease and plants, pipelines, or natural gas vehicles. [c]Includes consumption for industrial CHP plants, a small number of electricity-only plants, and GTL plants for heat and power production; excludes consumption by nonutility generators. [d]Includes lease and plant fuel. [e]Includes consumption of energy by electricity-only and CHP plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes electric utilities, small power producers, and exempt wholesale generators. [f]With the exception of IHSGI and IER, includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles. IHSGI includes lease and plant fuel with industrial consumption. IER includes agricultural and non-energy use in other consumption. [g]2007 wellhead natural gas prices for EVA and DB are $6.68 and $6.91 per thousand cubic feet, respectively. [h]The 2007 industrial natural gas prices for IHSGI and SEER are $8.56 and $7.59 per thousand cubic feet, respectively.

Sources: **2007 and *AEO2009*:** AEO2009 National Energy Modeling System, run AEO2009.D120908A. **IHSGI:** IHS Global Insight, Inc., *2008 U.S. Energy Outlook* (September 2008). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (January 2009). **DB:** Deutsche Bank AG estimates (September 2008). **IER:** Institute of Energy Economics and the Rational Use of Energy at the University of Stuttgart, TIAM Global Energy System Model (November 2008). **SEER:** Strategic Energy and Economic Research, Inc., "SEER Balanced Portfolio, $45 per ton Carbon Tax 2015" (April 2008). **Altos:** Altos World Gas Trade Model (October 2008).

subsequent decline, with total pipeline imports in 2030 at the highest level among all the projections but still 0.6 trillion cubic feet below the 2007 level.

Net LNG imports in the *AEO2009* reference case are considerably lower than in any of the other projections, at less than 1.0 trillion cubic feet in 2030. EVA and IER are far more optimistic about the potential for increased LNG imports, with 2030 levels near 6 trillion cubic feet. Altos projects the highest level of LNG imports, at 11.0 trillion cubic feet in 2030, and IHSGI, DB, and SEER project more modest increases.

U.S. domestic natural gas production increases through 2015 in all the projections except IER's. SEER shows the highest production levels in 2015, at 22.1 trillion cubic feet. After 2015, only IHSGI and *AEO2009* show domestic production continuing to increase through 2030. The domestic production share of total natural gas supply in the *AEO2009* reference case increases steadily, to more than 95 percent in 2030, as compared with the DB projection, which shows the domestic share consistent at around 80 percent. The other projections show declines in domestic natural gas production from 2015 to 2030. IER has the lowest level in 2030, at 13.8 trillion cubic feet. In the EVA, IER, and Altos projections, domestic production represents a much smaller share of total natural gas supply in 2030, at less than 70 percent.

Natural gas wellhead prices in the United States, which were $6.39 per thousand cubic feet in 2007, increase steadily in all the projections, with some exceptions in 2015. Altos, IER, and DB project higher average prices in 2030 than *AEO2009*. IHSGI, EVA, and SEER project lower prices than *AEO2009*. SEER and Altos also include lower domestic production levels than the other projections. The highest wellhead price in 2030 is projected by Altos, at $10.13 per thousand cubic feet. The lowest is projected by SEER, at $7.28 per thousand cubic feet.

The price margins for delivered natural gas (the difference between delivered and wellhead prices) can vary significantly from year to year. In 2007, margins in the end-use sectors were notably higher than the historical average. In the *AEO2009* reference case, margins in the electricity generation and industrial sectors generally decline over the projection period, whereas margins in the residential and commercial sectors generally rise, because fixed costs are spread over lower per-customer volumes as consumption is reduced by efficiency improvements.

End-use prices in the IHSGI projection imply declining margins in all end-use sectors. The IER projections imply constant margins in all sectors except the industrial sector. In the SEER projection, margins remain relatively steady in the residential and industrial sectors through 2030. The industrial sector margins in the SEER projection are approximately $0.40 per thousand cubic feet higher than those in the *AEO2009* projection from 2015 to 2030, and those in the IER projection are about $1.65 per thousand cubic feet higher than in *AEO2009*. Margins in the electricity generation sector are similar in the *AEO2009* and IHSGI projections, and both are lower than in the IER and SEER projections.

Liquid Fuels

In the *AEO2009* reference case, the world oil price is $111 per barrel in 2015 and rises to $130 per barrel in 2030 (see Table 16). In the DB projection, real crude oil prices are $72 per barrel in 2015, $68 per barrel in 2025, and $70 per barrel in 2030. Not surprisingly, domestic crude oil production is lower and total net imports are higher in the DB projections than in *AEO2009* (Table 20).

A major difference between the *AEO2009* reference case and all but one of the other projections—IHSGI, DB, IER, Purvin and Gertz, Inc. (P&G), and IEA—is that the other projections assume less domestic crude oil production and a gradual decline in production in future years. The IER projection for oil production is particularly pessimistic in comparison with *AEO2009*. In general, the more pessimistic outlook in the other projections results in higher levels of total net imports and greater dependence on imports to meet supply needs. The one exception is EVA, which includes higher domestic crude oil production in 2015 than projected in the *AEO2009* reference case; however, EVA's projections for crude oil and natural gas liquids (NGL) production in 2025 and 2030 are lower than in *AEO2009*.

The *AEO2009* reference case is also the most bullish with respect to NGL production, with the exception of IHSGI. Both IER and DB show lower NGL production than *AEO2009*, with IER being much lower. The difference can be explained, at least in part, by lower projections of natural gas production in the DB and IER cases. Both projections show a steady decline in natural gas production after 2020 (earlier in the IER case), whereas *AEO2009* shows a slow but steady increase through 2030. The highest projection for U.S.

Table 20. Comparison of liquids projections, 2015, 2025, and 2030 (million barrels per day, except where noted)

Projection	2007	AEO2009 reference case	Other projections: IHSGI	EVA	DB	IER	P&G	IEA
		2015						
Crude oil and NGL production	**6.85**	**7.61**	**6.60**	**8.15**	**6.74**	**5.08**	**NA**	**6.80**
Crude oil	5.07	5.72	4.56	6.39	5.04	4.29	4.36	NA
Natural gas liquids	1.78	1.89	2.02	1.76	1.70	0.78	NA	NA
Total net imports	**12.09**	**9.74**	**12.11**	**NA**	**11.38**	**12.97**	**11.48**	**NA**
Crude oil	10.00	8.10	11.10	NA	NA	NA	11.68	NA
Petroleum products	2.09	1.64	1.02	NA	NA	NA	-0.20	NA
Petroleum demand	**20.65**	**20.16**	**21.07**	**NA**	**19.69**	**18.05**	**18.28**	**18.75**
Motor gasoline	9.29	8.97	9.09	NA	9.01	7.57	8.99	NA
Jet fuel	1.63	1.52	1.72	NA	1.52	1.99	1.59	NA
Distillate fuel	4.20	4.46	4.55	NA	4.00	3.49	4.23	NA
Residual fuel	0.72	0.69	0.69	NA	0.60	0.64	0.51	NA
Other	4.82	4.52	5.02	NA	4.56	4.36	2.96	NA
Net import share of petroleum demand (percent)	**59**	**49**	**57**	**NA**	**58**	**72**	**63**	**NA**
		2025						
Crude oil and NGL production	**6.85**	**9.14**	**5.74**	**7.05**	**5.28**	**3.80**	NA	**NA**
Crude oil	5.07	7.21	3.71	5.61	4.01	3.07	3.24	NA
Natural gas liquids	1.78	1.93	2.03	1.44	1.27	0.73	NA	NA
Total net imports	**12.09**	**8.01**	**12.61**	**NA**	**13.88**	**15.58**	**12.51**	**NA**
Crude oil	10.00	6.66	12.06	NA	NA	NA	12.37	NA
Petroleum products	2.09	1.35	0.56	NA	NA	NA	0.14	NA
Petroleum demand	**20.65**	**20.76**	**21.77**	**NA**	**21.05**	**19.37**	**18.15**	**NA**
Motor gasoline	9.29	8.15	8.12	NA	9.59	7.89	7.82	NA
Jet fuel	1.62	1.81	2.04	NA	1.62	2.28	1.78	NA
Distillate fuel	4.20	4.91	5.61	NA	4.36	4.00	4.92	NA
Residual fuel	0.72	0.71	0.65	NA	0.63	0.74	0.42	NA
Other	4.82	5.18	5.35	NA	4.85	4.46	3.22	NA
Net import share of petroleum demand (percent)	**59**	**40**	**58**	**NA**	**66**	**80**	**63**	**NA**
		2030						
Crude oil and NGL production	**6.85**	**9.29**	**5.36**	**6.28**	**4.78**	**3.15**	**NA**	**6.50**
Crude oil	5.07	7.37	3.30	4.97	3.63	2.45	2.84	NA
Natural gas liquids	1.78	1.92	2.06	1.31	1.15	0.70	NA	NA
Total net imports	**12.09**	**8.35**	**13.49**	**NA**	**14.99**	**16.53**	**12.80**	**NA**
Crude oil	10.00	6.95	12.46	NA	NA	NA	12.66	NA
Petroleum products	2.09	1.40	1.02	NA	NA	NA	0.15	NA
Petroleum demand	**20.65**	**21.67**	**22.27**	**NA**	**21.69**	**19.69**	**18.15**	**18.41**
Motor gasoline	9.29	8.04	7.65	NA	9.83	8.10	7.45	NA
Jet fuel	1.62	1.99	2.21	NA	1.66	2.17	1.85	NA
Distillate fuel	4.20	5.42	6.26	NA	4.58	4.29	5.14	NA
Residual fuel	0.72	0.72	0.64	NA	0.65	0.79	0.40	NA
Other	4.82	5.50	5.51	NA	4.97	4.34	3.30	NA
Net import share of petroleum demand (percent)	**59**	**41**	**61**	**NA**	**69**	**84**	**71**	**NA**

NA = Not available.

Sources: ***2007 and AEO2009:*** AEO2008 National Energy Modeling System, run AEO2009.D120908A. **IHSGI:** IHS Global Insight, Inc., *Global Petroleum Outlook, Fall 2008* (Lexington, MA, November 2008). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (January 2009). **DB:** Deutsche Bank AG, e-mail from Adam Sieminski on November 4, 2008. **IER:** Institute of Energy Economics and the Rational Use of Energy at the University of Stuttgart, e-mail from Markus Blesl on December 1, 2008. **P&G:** Purvin and Gertz, Inc., *2008 Global Petroleum Market Outlook* (February 2009). **IEA:** International Energy Agency, *World Energy Outlook 2008* (Paris, France, November 2008).

NGL production is by IHSGI, consistent with its outlook for a significant increase in natural gas production through 2015, to a level higher than the *AEO2009* projection for 2015. *AEO2009* projects more natural gas production in 2025 and 2030 than in the IHSGI projection, however, suggesting that IHSGI assumes higher yields of NGL from the production of natural gas.

With the exception of IEA and P&G, liquids demand is similar in all the projections. The IEA petroleum demand projection is lower than the others, possibly reflecting IEA's assumptions of generally higher prices for oil and petroleum products, which depress demand and create an incentive for more use of alternative fuels and improvements in fuel efficiency. The IEA projection also includes more pessimistic assumptions about U.S. (and worldwide) economic growth. Although P&G projects a lower oil price than the *AEO2009* reference case, the lower GDP growth rate in the P&G projection leads to significantly lower demand in all categories in the later years of the projections.

Both the DB and IER cases show increasing demand for motor gasoline in the long term. In the *AEO2009* reference case, motor gasoline demand declines as a result of new CAFE standards and a steady increase in ethanol supply throughout the projection. Demand for gasoline also falls in the IHSGI projection, in large part because of its optimistic projection for ethanol consumption, at 2.02 million barrels per day (31 billion gallons per year) of ethanol in 2030.

Demand for distillate fuel increases throughout all the projections, presumably because of rapid growth in freight and ship movement, leading to increased consumption of diesel fuel, during the economic recovery. Jet fuel demand also increases from 2015 to 2030 in all the projections except IER.

Coal

The outlook for coal markets varies considerably across the projections compared in Table 21. Differences in assumptions about expectations for and implementation of legislation aimed at reducing GHG emissions can lead to significantly different projections for coal production, consumption, and prices. In addition, different assumptions about world oil prices, natural gas prices, and economic growth can contribute to variation across the projections.

In the *AEO2009* reference case, total U.S. coal consumption increases to 1,363 million tons (26.6 quadrillion Btu) in 2030. Total coal consumption also increases in the IEA projection, to 25.1 quadrillion Btu in 2030, which is closer to the *AEO2009* projection than are any of the others. Total coal consumption decreases from 2007 levels to 991 million tons and 21.4 quadrillion Btu in 2030 in the IER and DB projections, respectively. IHSGI projects relatively constant total coal consumption over the projection period, with a slight overall increase from 2007 levels to 1,150 million tons in 2030.

In the *AEO2009* projection, coal production increases to 1,248 milliion tons (25.1 quadrillion Btu) in 2025 and 1,341 million tons (26.9 quadrillion Btu) in 2030. Similar increases are projected by IEA and Hill and Associates (WM), to 27.3 quadrillion Btu in 2030 and 1,361 million tons in 2025, respectively. Coal production falls slightly from 2007 levels in the IER projection, to 1,035 million tons in 2030. In the IHSGI projection, production remains relatively constant, increasing slightly to 1,158 million tons in 2030.

With the exception of IER and WM, the other projections show net U.S. coal exports as flat or decreasing. In the *AEO2009* reference case, the United States becomes a net importer of coal, with coal exports declining to 44 million tons and imports increasing to 53 million tons in 2030. The IHSGI and IER projections show net U.S. exports in 2030 at 9 million tons and 44 million tons, respectively, with IER's projection of 72 million tons of coal exports in 2030 the highest among all the projections.

Minemouth coal prices in 2030 are higher than in 2007 in all the projections except IHSGI. *AEO2009* shows the minemouth price increasing to $28.45 per ton ($1.42 per million Btu) in 2025 and $29.10 per ton ($1.46 per million Btu) in 2030, compared with $34.43 per ton ($1.66 per million Btu) in 2030 projected by IER and $32.26 per ton ($1.62 per million Btu) in 2025 projected by WM. In the IHSGI projection, the minemouth coal price falls to $21.63 per ton ($1.05 per million Btu) in 2030.

Table 21. Comparison of coal projections, 2015, 2025, and 2030 (million short tons, except where noted)

Projection	2007	AEO2009 reference case	Other projections				
			IHSGI	DB	IER	IEA	WM
		2015					
Production	**1,147**	**1,206**	**1,167**	**NA**	**896**	**24.8** [a]	**1,225** [b]
Consumption by sector							
Electric power	1,046	1,096	1,069	NA	752	NA	NA
Coke plants	23	20	22	NA	37	NA	NA
Coal-to-liquids	0	17	NA	NA	28	NA	NA
Other industrial/buildings	60	60	59	NA	73	NA	NA
Total	**1,129**	**1,192**	**1,150**	**23.0** [a]	**890**	**23.0** [a]	**NA**
Net coal exports	**25**	**28**	**17**	**NA**	**6**	**NA**	**16**
Exports	59	65	57	NA	33	NA	37
Imports	34	38	40	NA	27	NA	22
Minemouth price							
(2007 dollars per short ton)	25.82	28.71	23.79 [c]	NA	34.43 [d]	NA	32.27 [d]
(2007 dollars per million Btu)	1.27	1.42	1.15	NA	1.66 [d]	NA	1.61 [d]
Average delivered price to electricity generators							
(2007 dollars per short ton)	35.45	38.47	37.47 [c]	NA	42.30 [d]	NA	49.24 [d]
(2007 dollars per million Btu)	1.78	1.94	1.81	NA	2.04 [d]	NA	2.51 [d]
		2025					
Production	**1,147**	**1,248**	**1,158**	**NA**	**1,046**	**NA**	**1,361** [a]
Consumption by sector							
Electric power	1,046	1,126	1,071	NA	815	NA	NA
Coke plants	23	18	20	NA	38	NA	NA
Coal-to-liquids	0	48	NA	NA	53	NA	NA
Other industrial/buildings	60	59	56	NA	85	NA	NA
Total	**1,129**	**1,252**	**1,147**	**21.9** [a]	**991**	**25.0** [a]	**NA**
Net coal exports	**25**	**8**	**10**	**NA**	**56**	**NA**	**33**
Exports	59	53	48	NA	72	NA	52
Imports	34	45	38	NA	16	NA	18
Minemouth price							
(2007 dollars per short ton)	25.82	28.45	22.21 [c]	NA	34.43 [d]	NA	32.26 [d]
(2007 dollars per million Btu)	1.27	1.42	1.07	NA	1.66 [d]	NA	1.62 [d]
Average delivered price to electricity generators							
(2007 dollars per short ton)	35.45	38.83	35.40 [c]	NA	42.30 [d]	NA	50.17 [d]
(2007 dollars per million Btu)	1.78	1.96	1.71	NA	2.04 [d]	NA	2.52 [d]

Btu = British thermal unit. NA = Not available. See notes and sources at end of table.

Table 21. Comparison of coal projections, 2015, 2025, and 2030 (continued)
(million short tons, except where noted)

Projection	2007	AEO2009 reference case	Other projections				
			IHSGI	DB	IER	IEA	WM
			2030				
Production	1,147	1,341	1,158	NA	1,035	27.3 [a]	NA
Consumption by sector							
Electric power	1,046	1,215	1,077	NA	797	NA	NA
Coke plants	23	18	20	NA	37	NA	NA
Coal-to-liquids	0	70	NA	NA	69	NA	NA
Other industrial/buildings	60	60	53	NA	88	NA	NA
Total	1,129	1,363	1,150	21.4 [a]	991	25.1 [a]	NA
Net coal exports	25	-10	9	NA	44	NA	NA
Exports	59	44	46	NA	72	NA	NA
Imports	34	53	38	NA	27	NA	NA
Minemouth price							
(2007 dollars per short ton)	25.82	29.10	21.63 [c]	NA	34.43 [d]	NA	NA
(2007 dollars per million Btu)	1.27	1.46	1.05	NA	1.66 [d]	NA	NA
Average delivered price to electricity generators							
(2007 dollars per short ton)	35.45	40.61	34.90 [c]	NA	42.30 [d]	NA	NA
(2007 dollars per million Btu)	1.78	2.04	1.69	NA	2.04 [d]	NA	NA

Btu = British thermal unit. NA = Not available.
[a]Reported in quadrillion Btu.
[b]Reported in thermal thousand tons; does not include petroleum coke or waste coal.
[c]Imputed, using heat conversion factor implied by U.S. steam coal consumption figures for the electricity sector.
[d]Converted to 2007 dollars, using the *AEO2009* GDP inflator.
Sources: ***2007 and AEO2009:*** AEO2009 National Energy Modeling System, run AEO2009.D120908A. **IHSGI:** IHS Global Insight, Inc., *2008 U.S. Energy Outlook* (September 2008). **DB:** Deutsche Bank AG, e-mail from Adam Sieminski on November 4, 2008. **IER:** Institute of Energy Economics and the Rational Use of Energy at the University of Stuttgart, TIAM Global Energy System Model (November 2008). **IEA:** International Energy Agency, *World Energy Outlook 2008* (Paris, France, November 2008).**WM:** Hill and Associates, a Wood Mackenzie Company, *Fall 2008 Long Term Outlook Base Case* and *2008 International Coal Trade Base Case*.

List of Acronyms

A.B.	Assembly Bill
ACP	Alternative compliance payment
AD	Associated-dissolved (natural gas)
AEO	*Annual Energy Outlook*
AEO2008	*Annual Energy Outlook 2008*
AEO2009	*Annual Energy Outlook 2009*
ANWR	Arctic National Wildlife Refuge
ARRA2009	American Recovery and Reinvestment Act of 2009
BLS	Bureau of Labor Statistics
BTL	Biomass-to-liquids
Btu	British thermal unit
CAA	Clean Air Act
CAFE	Corporate Average Fuel Economy
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CARB	California Air Resources Board
CBO	Congressional Budget Office
CCS	Carbon capture and storage
CERA	Cambridge Energy Research Associates
CHP	Combined heat and power
CNG	Compressed natural gas
CO_2	Carbon dioxide
CREB	Clean and Renewable Energy Bonds
CTL	Coal-to-liquids
CZMA	Coastal Zone Management Act of 1972
DB	Deutsche Bank AG
DOE	U.S. Department of Energy
DOER	State Department of Energy Resources (Massachusetts)
DOJ	U.S. Department of Justice
E85	Fuel containing a blend of 70 to 85 percent ethanol and 30 to 15 percent gasoline by volume
EIA	Energy Information Administration
EIEA2008	Energy Improvement and Extension Act of 2008
EISA2007	Energy Independence and Security Act of 2007
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EPACT2005	Energy Policy Act of 2005
EPACT92	Energy Policy Act of 1992
EVA	Energy Ventures Analysis, Inc.
FAME	Fatty acid methyl ester
FFV	Flex-fuel vehicle
FGD	Flue gas desulfurization
GDP	Gross domestic product
GHG	Greenhouse gas
GTL	Gas-to-liquids
GVWR	Gross vehicle weight rating
HEV	Hybrid electric vehicle
H.R.	House of Representatives
ICE	Internal combustion engine
IEA	International Energy Agency
IER	Institute of Energy Economics and the Rational Use of Energy at the University of Stuttgart
IHSGI	IHS Global Insight
INFORUM	Interindustry Forecasting Project at the University of Maryland
IRP	Integrated resource plan
IRR	Internal rate of return
ITC	Investment tax credit
LCFS	Low Carbon Fuel Standard (California)
LDV	Light-duty vehicle
Li-Ion	Lithium-ion
LNG	Liquefied natural gas
LPG	Liquid petroleum gas
MHEV	Micro hybrid electric vehicle
MMS	Minerals Management Service
mpg	Miles per gallon
MSAT2	Mobile Source Air Toxics Rule (February 2007)
MTBE	Methyl tertiary butyl ether
MY	Model year
NA	Nonassociated (natural gas)
NAAQS	National Ambient Air Quality Standards
NAECA	National Appliance Energy Conservation Act
NEMS	National Energy Modeling System (EIA)
NGL	Natural gas liquids
NHTSA	National Highway Traffic Safety Administration
NiMH	Nickel metal hydride
NO_x	Nitrogen oxide
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
OECD	Organization for Economic Cooperation and Development
OMB	Office of Management and Budget
OPEC	Organization of the Petroleum Exporting Countries
P.L.	Public Law
P&G	Purvin and Gertz, Inc.
PHEV	Plug-in hybrid electric vehicle
PHEV-10	PHEV designed to travel about 10 miles on battery power alone
PHEV-20	PHEV designed to travel about 20 miles on battery power alone
PHEV-40	PHEV designed to travel about 40 miles on battery power alone
$PM_{2.5}$	Particulate matter with a diameter less than or equal to 2.5 microns
PTC	Production tax credit
PV	Solar photovoltaic
REC	Renewable energy credit
RFG	Reformulated gasoline
RFS	Renewable fuels standard
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable portfolio standard
SCR	Selective catalytic control equipment
SEER	Strategic Energy and Economic Research, Inc.
SLA	Submerged Lands Act
SO_2	Sulfur dioxide
SSA	Social Security Administration
TAPS	Trans Alaska Pipeline System
WCI	Western Climate Initiative
WM	Hill and Associates, a Wood Mackenzie Company
WTI	West Texas Intermediate (crude oil)

Notes and Sources

Table Notes and Sources

Note: Tables indicated as sources in these notes refer to the tables in Appendixes A, B, C, and D of this report.

Table 1. Estimated fuel economy for light-duty vehicles, based on proposed CAFE standards, 2010-2015: National Highway Traffic Safety Administration, *Average Fuel Economy Standards: Passenger Cars and Light Trucks Model Years 2011-2015*, Notice of Proposed Rulemaking, 49 CFR Parts 523, 531, 533, 534, 536, and 537 [Docket No. NHTSA 2008-2009], RIN 2127-AK29 (Washington, DC, April 2008), pp. 14-15, web site www.nhtsa.dot.gov/portal/site/nhtsa/menuitem.43ac99aefa80569eea57529cdba046a0.

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Table 7. Conventional vehicle and plug-in hybrid system component costs for mid-size vehicles at volume production: Electric Power Research Institute, *Advanced Batteries for Electric-Drive Vehicles*, 1009299 (Palo Alto, CA, May 2004), web site www.spinnovation.com/sn/Batteries/Advanced_Batteries_for_Electric-Drive_Vehicles.pdf. Note that this is one cost estimate among several that were used in the analysis and that PHEV system costs increase as the all-electric range of the vehicle increases.

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Table 11. Assumptions for comparison of three Alaska North Slope natural gas facility options: Gas Conversion Efficiency: LNG facility efficiency does not include any LNG tanker losses while in transit; pipeline efficiency based on averages cited in documentation for the Alaska Gasline Inducement Act, web site http://gov.state.ak.us/agia; LNG and GTL losses based on levels cited in technical literature. Source: B. Patel, *Gas Monetisation: A Techno-Economic Comparison of Gas-To-Liquid and LNG* (Glasgow, Scotland: Foster Wheeler Energy Limited, 2005). **Capital Costs:** Gathering and treatment costs based on ConocoPhilips AGIA proposal costs. LNG capital costs based on liquefaction plant estimates provided by Robert Baron, a DOE Fossil Energy consultant, and prorated AGIA gas pipeline costs based on the mileage from the North Slope to Valdez, and escalated by 20 percent to reflect the cost of building over the Alaska Range mountains in a seismically active zone. GTL North Slope capital cost based on $110,000 per daily stream barrel as cited in K. Nelson, "Legislators Told GTL a No-Go for ANS Gas," *Petroleum News*, Vol. 12, No. 10 (March 11, 2007), web site www.petroleumnews.com/pnads/786285153.shtml. **Operating Costs:** Pipeline operating costs based on EIA's NGTDM model values. LNG operating costs based on study by Robert Baron. GTL operating costs are based on EIA's INGM model.

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Table 13. Comparison of gasoline and natural gas passenger vehicle attributes: Honda Motors, web site http://automobiles.honda.com (as of February 10, 2009). Data taken from Honda's 2009-civic-sedan-fact.sheet.pdf and 2009-civic-gx-fact.sheet.pdf. Vehicle comparison based on 4-door sedans equipped with automatic transmission. The natural gas vehicle's fuel gallon is "gasoline equivalent gallons" based on 3,600 pounds per square inch of natural gas cylinder pressure.

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Figure Notes and Sources

Note: Tables indicated as sources in these notes refer to the tables in Appendixes A, B, C, and D of this report.

Figure 1. Total liquid fuels demand by sector: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

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Figure 3. New light-duty vehicle sales shares by type: History, Light Trucks: Energy Information Administration, Office of Integrated Analysis and Forecasting using data from National Highway Traffic Safety Administration. **History, Passenger Cars:** National Highway Traffic Safety Administration, *New Passenger Car Fleet Average Characteristics*, web site www.nhtsa.gov/cars/rules/CAFE/NewPassengerCarFleet.htm. **Projections:** AEO2009 National Energy Modeling System, runs AEO2009.D120908A, NORSK2009.D120908A, and CAP2009.D010909A.

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Figure 5. Proposed CAFE standards for light trucks by vehicle footprint, model years 2011-2015: Energy Information Administration, Office of Integrated Analysis and Forecasting.

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Figure 9. Incremental cost of PHEV purchase with EIEA2008 tax credit included compared with conventional ICE vehicle purchase, by PHEV all-electric driving range, 2010, 2020, and 2030: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 10. PHEV fuel savings and incremental vehicle cost by gasoline price and PHEV all-electric driving range, 2030: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 11. PHEV fuel savings and incremental vehicle cost by gasoline price and PHEV all-electric driving range, 2010 and 2020: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 12. PHEV annual fuel savings per vehicle by all-electric driving range: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 13. U.S. total domestic oil production in two cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009

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Figure 15. Average internal rates of return for three Alaska North Slope natural gas facility options in three cases, 2011-2020: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 16. Average internal rates of return for three Alaska North Slope natural gas facility options in three cases, 2021-2030: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 17. Ratio of crude oil price to natural gas price in three cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, runs AEO2009.D120908A, LP2009.D122308A, and HP2009.D121108A.

Figure 18. Cumulative additions to U.S. electricity generation capacity by fuel in four cases, 2008-2030: AEO2009 National Energy Modeling System, runs AEO2009.D120908A, FRZCST09.D121108A, INCCST09.D121208A, and DECCST09.D121108A.

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Figure 22. Installed renewable generation capacity in two cases, 2007-2030: 2007: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, runs AEO2009.D120908A and PTC09.D010709A.

Figure 23. Cumulative additions to U.S. generating capacity in three cases, 2008-2030: AEO2009 National Energy Modeling System, runs AEO2009.D120908A, NORSK2009.D120908A, and CAP2009.D010909A.

Figure 24. U.S. electricity generation by source in three cases, 2007 and 2030: 2007: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, runs AEO2009.D120908A, NORSK2009.D120908A, and CAP2009.D010909A.

Figure 25. U.S. electricity prices in three cases, 2005-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, runs AEO2009.D120908A, NORSK2009.D120908A, and CAP2009.D010909A.

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Figure 27. Average annual growth rates of real GDP, labor force, and productivity in three cases, 2007-2030: Appendix B, Table B4.

Figure 28. Average annual inflation, interest, and unemployment rates in three cases, 2007-2030: Appendix B, Table B4.

Figure 29. Sectoral composition of industrial output growth rates in three cases, 2007-2030: AEO2009 National Energy Modeling System, runs AEO2009.D120908A, HM2009.D120908A, and LM2009.D120908A.

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Figure 31. Energy expenditures as a share of gross domestic product, 1970-2030: History: U.S. Department of Commerce, Bureau of Economic Analysis, and Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 32. World oil prices in three cases, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, runs AEO2009.D120908A, LP2009.D122308A, and HP2009.D121108A.

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Figure 34. World liquids production shares by region in three cases, 2007 and 2030: AEO2009 National Energy Modeling System, runs AEO2009.D120908A, LP2009.D122308A, and HP2009.D121108A.

Figure 35. Energy use per capita and per dollar of gross domestic product, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 36. Primary energy use by end-use sector, 2007-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** Appendix A, Table A2.

Figure 37. Primary energy use by fuel, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

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Figure 39. Residential delivered energy consumption by fuel and service, 2007, 2015, and 2030: AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 40. Efficiency gains for selected residential appliances in three cases, 2030: Energy Information Administration, *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Navigant Consulting, Inc., September 2007); and AEO2009 National Energy Modeling System, runs AEO2009.D120908A, BLDFRZN.D121008A, and BLDBEST.D121008A.

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Figure 42. Commercial delivered energy consumption per capita in three cases, 1980-2030: History: Energy Information Administration, "Consumption, Price, and Expenditure Estimates" (November 2008), web site www.eia.doe.gov/emeu/states/_seds.html, and *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, runs AEO2009.D120908A, BLDFRZN.D121008A, and BLDHIGH.D121008A.

Figure 43. Commercial delivered energy consumption by fuel and service, 2007, 2015, and 2030: AEO2009 National Energy Modeling System, run AEO2009.D120908A.

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Figure 46. Industrial delivered energy consumption by application, 2007-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

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Figure 53. Sales shares of hybrid light-duty vehicles by type in three cases, 2030: AEO2009 National Energy Modeling System, run AEO2009.D120908A.

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Figure 57. Levelized electricity costs for new power plants, 2020 and 2030: AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 58. Average U.S. retail electricity prices in three cases, 1970-2030: AEO2009 National Energy Modeling System, runs AEO2009.D120908A, LM2009.D120908A, and HM2009.D120908A.

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Figure 61. Grid-connected electricity generation from renewable energy sources, 1990-2030: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

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Figure 64. Lower 48 wellhead and Henry Hub spot market prices for natural gas, 1990-2030: History: Lower 48 wellhead prices: Energy Information Administration, *Natural Gas Annual, 2006*, DOE/EIA-0131(2006) (Washington, DC, June 2008). **Henry Hub natural gas prices:** Energy Information Administration, *Short-Term Energy Outlook* Query System, Monthly Natural Gas Data, Variable NGHHMCF. **Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 65. Lower 48 wellhead natural gas prices in five cases, 2007-2030: History: Energy Information Administration, *Natural Gas Annual 2006*, DOE/EIA-0131 (2007) (Washington, DC, June 2008). **Projections:** AEO-2009 National Energy Modeling System, runs AEO2009.D120908A, HM2009.D120908A, LM2009.D120908A, OGHTEC09.D121408A, and OGLTEC09. D121408A.

Figure 66. Natural gas production by source, 1990-2030: History: Energy Information Administration, Office of Integrated Analysis and Forecasting. **Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 67. Total U.S. natural gas production in five cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, runs AEO2009.D120908A, HP2009.D121108A, OGHTEC09.D121408A, LP2009.D122308A, and OGLTEC09.D121408A.

Figure 68. Net U.S. imports of natural gas by source, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 69. Lower 48 wellhead prices for natural gas in two cases, 1990-2030: History: Energy Information Administration, *Natural Gas Annual 2006*, DOE/EIA-0131 (2006) (Washington, DC, June 2008). **Projections:** AEO-2009 National Energy Modeling System, runs AEO2009.D120908A and NOAK09.D121408A.

Figure 70. Domestic crude oil production by source, 1990-2030: History: Energy Information Administration, Office of Integrated Analysis and Forecasting. **Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 71. Total U.S. crude oil production in five cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, runs AEO2009.D120908A, HP2009.D121108A, OGHTEC09.D121408A, LP2009.D122308A, and OGLTEC09.D121408A.

Figure 72. Liquids production from gasification and oil shale, 2007-2030: AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 73. Liquid fuels consumption by sector, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 74. RFS credits earned in selected years, 2007-2030: AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 75. Biofuel content of U.S. motor gasoline and diesel consumption, 2007, 2015, and 2030: AEO-2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 76. Motor gasoline, diesel fuel, and E85 prices, 2007-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384 (2007) (Washington, DC, June 2008). **Projections:** AEO-2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 77. Net import share of U.S. liquid fuels consumption in three cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, runs AEO2009.D120908A, LP2009.D122308A, and HP2009.D121108A.

Figure 78. Coal production by region, 1970-2030: History (short tons): 1970-1990: Energy Information Administration, *The U.S. Coal Industry, 1970-1990: Two Decades of Change*, DOE/EIA-0559 (Washington, DC, November 2002). **1991-2000:** Energy Information Administration, *Coal Industry Annual*, DOE/EIA-0584 (various years). **2001-2007:** Energy Information Administration, *Annual Coal Report 2007*, DOE/EIA-0584(2007) (Washington, DC, September 2008), and previous issues. **History (conversion to quadrillion Btu): 1970-2007: Estimation Procedure:** Energy Information Administration, Office of Integrated Analysis and Forecasting. Estimates of average heat content by region and year are based on coal quality data collected through various energy surveys (see sources) and national-level estimates of U.S. coal production by year in units of quadrillion Btu, published in EIA's *Annual Energy Review*. **Sources:** Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008), Table 1.2; Form EIA-3, "Quarterly Coal Consumption and Quality Report, Manufacturing Plants"; Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants"; Form EIA-6A, "Coal Distribution Report"; Form EIA-7A, "Coal Production

Report"; Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report"; Form EIA-906, "Power Plant Report"; Form EIA-920, "Combined Heat and Power Plant Report"; U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM 545"; and Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." **Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A. **Note:** For 1989-2030, coal production includes waste coal.

Figure 79. U.S. coal production in four cases, 2007, 2015, and 2030: AEO2009 National Energy Modeling System, runs AEO2009.D120908A, CAP2009.D010909A, NORSK2009.D120908A, LCCST09.D121608A, and HCCST09.D121608A. **Note:** Coal production includes waste coal.

Figure 80. Average minemouth coal prices by region, 1990-2030: History (dollars per short ton): 1990-2000: Energy Information Administration, *Coal Industry Annual*, DOE/EIA-0584 (various years). **2001-2007:** Energy Information Administration, *Annual Coal Report 2007*, DOE/EIA-0584 (2007) (Washington, DC, September 2008), and previous issues. **History (conversion to dollars per million Btu): 1970-2007:** Estimation Procedure: Energy Information Administration, Office of Integrated Analysis and Forecasting. Estimates of average heat content by region and year based on coal quality data collected through various energy surveys (see sources) and national-level estimates of U.S. coal production by year in units of quadrillion Btu published in EIA's *Annual Energy Review*. **Sources:** Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008), Table 1.2; Form EIA-3, "Quarterly Coal Consumption and Quality Report, Manufacturing Plants"; Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants"; Form EIA-6A, "Coal Distribution Report"; Form EIA-7A, "Coal Production Report"; Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report"; Form EIA-906, "Power Plant Report"; and Form EIA-920, "Combined Heat and Power Plant Report"; U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM 545"; and Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." **Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A. **Note:** Includes reported prices for both open-market and captive mines.

Figure 81. Carbon dioxide emissions by sector and fuel, 2007 and 2030: History: 1980-2006: Energy Information Admininstration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008), Table 12.2. **2007:** Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2007*, DOE/EIA-0573(2007) (Washington, DC, December 2008). **2030:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 82. Sulfur dioxide emissions from electricity generation, 1995-2030: History: 1995: U.S. Environmental Protection Agency, *National Air Pollutant Emissions Trends, 1990-1998*, EPA-454/R-00-002 (Washington, DC, March 2000). **2000:** U.S. Environmental Protection Agency, *Acid Rain Program Preliminary Summary Emissions Report, Fourth Quarter 2004*, web site www.epa.gov/airmarkets/emissions/prelimarp/index.html. **2007 and Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 83. Nitrogen oxide emissions from electricity generation, 1995-2030: History: 1995: U.S. Environmental Protection Agency, *National Air Pollutant Emissions Trends, 1990-1998*, EPA-454/R-00-002 (Washington, DC, March 2000). **2000:** U.S. Environmental Protection Agency, *Acid Rain Program Preliminary Summary Emissions Report, Fourth Quarter 2004*, web site www.epa.gov/airmarkets/emissions/prelimarp/index.html. **2007 and Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Appendixes

Table A1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Production								
Crude Oil and Lease Condensate	10.80	10.73	12.19	12.40	14.06	15.63	15.96	1.7%
Natural Gas Plant Liquids	2.36	2.41	2.58	2.55	2.57	2.62	2.61	0.3%
Dry Natural Gas	18.99	19.84	20.95	20.88	22.08	23.87	24.26	0.9%
Coal[1]	23.79	23.50	24.21	24.49	24.43	25.11	26.93	0.6%
Nuclear Power	8.21	8.41	8.45	8.68	8.99	9.04	9.47	0.5%
Hydropower	2.87	2.46	2.67	2.94	2.95	2.96	2.97	0.8%
Biomass[2]	2.97	3.23	4.20	5.18	6.52	7.83	8.25	4.2%
Other Renewable Energy[3]	0.88	0.97	1.54	1.63	1.74	1.95	2.19	3.6%
Other[4]	0.42	0.94	0.85	1.08	1.07	1.07	1.15	0.9%
Total	**71.29**	**72.49**	**77.64**	**79.83**	**84.41**	**90.09**	**93.79**	**1.1%**
Imports								
Crude Oil	22.08	21.90	17.76	17.82	16.09	14.76	15.39	-1.5%
Liquid Fuels and Other Petroleum[5]	7.22	6.97	5.59	5.69	5.67	5.79	6.33	-0.4%
Natural Gas	4.29	4.72	3.27	3.60	3.37	3.12	2.58	-2.6%
Other Imports[6]	0.98	0.99	0.89	0.96	1.19	1.11	1.35	1.3%
Total	**34.57**	**34.59**	**27.51**	**28.07**	**26.31**	**24.79**	**25.65**	**-1.3%**
Exports								
Petroleum[7]	2.59	2.84	2.56	2.68	2.90	3.06	3.17	0.5%
Natural Gas	0.73	0.83	0.70	1.16	1.44	1.71	1.87	3.6%
Coal	1.26	1.51	2.05	1.65	1.33	1.34	1.08	-1.4%
Total	**4.58**	**5.17**	**5.31**	**5.49**	**5.66**	**6.11**	**6.12**	**0.7%**
Discrepancy[8]	**1.26**	**0.01**	**-0.02**	**-0.46**	**-0.39**	**-0.29**	**-0.25**	**- -**
Consumption								
Liquid Fuels and Other Petroleum[9]	40.63	40.75	37.89	38.86	38.93	39.84	41.60	0.1%
Natural Gas	22.26	23.70	23.20	23.40	24.09	25.36	25.04	0.2%
Coal[10]	22.46	22.74	22.91	23.59	23.98	24.45	26.56	0.7%
Nuclear Power	8.21	8.41	8.45	8.68	8.99	9.04	9.47	0.5%
Hydropower	2.87	2.46	2.67	2.94	2.95	2.96	2.97	0.8%
Biomass[11]	2.52	2.62	2.99	3.59	4.58	5.27	5.51	3.3%
Other Renewable Energy[3]	0.88	0.97	1.54	1.63	1.74	1.95	2.19	3.6%
Other[12]	0.19	0.23	0.21	0.19	0.19	0.18	0.22	-0.2%
Total	**100.02**	**101.89**	**99.85**	**102.87**	**105.44**	**109.05**	**113.56**	**0.5%**
Prices (2007 dollars per unit)								
Petroleum (dollars per barrel)								
Imported Low Sulfur Light Crude Oil Price[13]	67.82	72.33	80.16	110.49	115.45	121.94	130.43	2.6%
Imported Crude Oil Price[13]	60.70	63.83	77.56	108.52	112.05	115.33	124.60	3.0%
Natural Gas (dollars per million Btu)								
Price at Henry Hub	6.91	6.96	6.66	6.90	7.43	8.08	9.25	1.2%
Wellhead Price[14]	6.48	6.22	5.88	6.10	6.56	7.13	8.17	1.2%
Natural Gas (dollars per thousand cubic feet)								
Wellhead Price[14]	6.66	6.39	6.05	6.27	6.75	7.33	8.40	1.2%
Coal (dollars per ton)								
Minemouth Price[15]	25.29	25.82	29.45	28.71	27.90	28.45	29.10	0.5%
Coal (dollars per million Btu)								
Minemouth Price[15]	1.25	1.27	1.44	1.42	1.39	1.42	1.46	0.6%
Average Delivered Price[16]	1.83	1.86	1.99	2.02	1.99	2.02	2.08	0.5%
Average Electricity Price (cents per kilowatthour)	9.1	9.1	9.0	9.1	9.4	9.8	10.4	0.6%

Table A1. Total Energy Supply and Disposition Summary (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Prices (nominal dollars per unit)								
Petroleum (dollars per barrel)								
Imported Low Sulfur Light Crude Oil Price[13]	66.04	72.33	84.42	127.84	149.14	168.24	189.10	4.3%
Imported Crude Oil Price[13]	59.10	63.83	81.69	125.57	144.74	159.11	180.66	4.6%
Natural Gas (dollars per million Btu)								
Price at Henry Hub	6.73	6.96	7.01	7.99	9.60	11.14	13.42	2.9%
Wellhead Price[14]	6.31	6.22	6.19	7.06	8.48	9.84	11.85	2.8%
Natural Gas (dollars per thousand cubic feet)								
Wellhead Price[14]	6.49	6.39	6.37	7.26	8.72	10.12	12.18	2.8%
Coal (dollars per ton)								
Minemouth Price[15]	24.63	25.82	31.02	33.22	36.04	39.26	42.20	2.2%
Coal (dollars per million Btu)								
Minemouth Price[15]	1.21	1.27	1.52	1.65	1.80	1.96	2.11	2.2%
Average Delivered Price[16]	1.78	1.86	2.10	2.34	2.57	2.79	3.01	2.1%
Average Electricity Price (cents per kilowatthour)	8.9	9.1	9.5	10.5	12.2	13.6	15.1	2.2%

[1]Includes waste coal.
[2]Includes grid-connected electricity from wood and waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[3]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy.
[4]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[5]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[6]Includes coal, coal coke (net), and electricity (net).
[7]Includes crude oil and petroleum products.
[8]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[9]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen. Refer to Table A17 for detailed renewable liquid fuels consumption.
[10]Excludes coal converted to coal-based synthetic liquids.
[11]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[12]Includes non-biogenic municipal waste and net electricity imports.
[13]Weighted average price delivered to U.S. refiners.
[14]Represents lower 48 onshore and offshore supplies.
[15]Includes reported prices for both open market and captive mines.
[16]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007). 2007 natural gas supply values and natural gas wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2006 natural gas wellhead price: Minerals Management Service and EIA, *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007). 2006 and 2007 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2007*, DOE/EIA-0584(2007) (Washington, DC, September 2008). 2007 petroleum supply values and 2006 crude oil and lease condensate production: EIA, *Petroleum Supply Annual 2007,* DOE/EIA-0340(2007)/1 (Washington, DC, July 2008). Other 2006 petroleum supply values: EIA, *Petroleum Supply Annual 2006,* DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). 2006 and 2007 low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2006 and 2007 coal values: *Quarterly Coal Report, October-December 2007*, DOE/EIA-0121(2007/4Q) (Washington, DC, March 2008). Other 2006 and 2007 values: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008).
Projections: EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Energy Consumption								
Residential								
Liquefied Petroleum Gases	0.49	0.50	0.49	0.48	0.49	0.50	0.52	0.2%
Kerosene	0.07	0.08	0.08	0.07	0.07	0.07	0.07	-0.5%
Distillate Fuel Oil	0.71	0.78	0.72	0.64	0.60	0.55	0.51	-1.8%
Liquid Fuels and Other Petroleum Subtotal	1.27	1.35	1.29	1.19	1.16	1.13	1.10	-0.9%
Natural Gas	4.49	4.86	4.92	5.01	5.10	5.13	5.07	0.2%
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-0.8%
Renewable Energy[1]	0.39	0.43	0.43	0.46	0.48	0.49	0.50	0.7%
Electricity	4.61	4.75	4.80	4.85	5.12	5.39	5.69	0.8%
Delivered Energy	**10.77**	**11.40**	**11.44**	**11.52**	**11.86**	**12.14**	**12.36**	**0.4%**
Electricity Related Losses	10.00	10.36	10.44	10.35	10.81	11.17	11.69	0.5%
Total	**20.77**	**21.76**	**21.88**	**21.87**	**22.67**	**23.31**	**24.05**	**0.4%**
Commercial								
Liquefied Petroleum Gases	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.3%
Motor Gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.4%
Kerosene	0.02	0.01	0.01	0.01	0.01	0.01	0.01	1.4%
Distillate Fuel Oil	0.40	0.41	0.36	0.34	0.34	0.34	0.34	-0.8%
Residual Fuel Oil	0.08	0.08	0.07	0.08	0.08	0.08	0.08	0.3%
Liquid Fuels and Other Petroleum Subtotal	0.63	0.63	0.58	0.58	0.58	0.59	0.59	-0.3%
Natural Gas	2.92	3.10	3.14	3.25	3.34	3.45	3.54	0.6%
Coal	0.07	0.07	0.06	0.06	0.06	0.06	0.06	-0.0%
Renewable Energy[3]	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.0%
Electricity	4.43	4.58	4.75	5.14	5.57	5.95	6.31	1.4%
Delivered Energy	**8.17**	**8.50**	**8.66**	**9.15**	**9.69**	**10.17**	**10.62**	**1.0%**
Electricity Related Losses	9.62	9.99	10.35	10.95	11.77	12.32	12.96	1.1%
Total	**17.79**	**18.49**	**19.01**	**20.10**	**21.46**	**22.49**	**23.59**	**1.1%**
Industrial[4]								
Liquefied Petroleum Gases	2.33	2.35	2.02	1.97	1.79	1.72	1.66	-1.5%
Motor Gasoline[2]	0.36	0.36	0.34	0.35	0.34	0.34	0.36	-0.1%
Distillate Fuel Oil	1.26	1.28	1.17	1.21	1.18	1.19	1.23	-0.1%
Residual Fuel Oil	0.24	0.25	0.15	0.16	0.16	0.16	0.16	-1.9%
Petrochemical Feedstocks	1.42	1.30	1.01	1.20	1.13	1.10	1.05	-0.9%
Other Petroleum[5]	4.51	4.42	3.74	3.82	3.72	3.72	3.84	-0.6%
Liquid Fuels and Other Petroleum Subtotal	10.13	9.96	8.42	8.71	8.32	8.22	8.30	-0.8%
Natural Gas	6.68	6.82	6.77	6.99	6.84	6.95	7.04	0.1%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and Plant Fuel[6]	1.16	1.20	1.27	1.25	1.33	1.44	1.47	0.9%
Natural Gas Subtotal	7.83	8.02	8.05	8.24	8.17	8.39	8.51	0.3%
Metallurgical Coal	0.60	0.60	0.55	0.53	0.49	0.48	0.48	-1.0%
Other Industrial Coal	1.25	1.21	1.24	1.16	1.15	1.16	1.16	-0.2%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.13	0.24	0.40	0.58	- -
Net Coal Coke Imports	0.06	0.03	0.01	0.01	0.01	0.01	0.01	-3.6%
Coal Subtotal	1.92	1.83	1.80	1.84	1.89	2.05	2.23	0.9%
Biofuels Heat and Coproducts	0.30	0.40	0.75	0.95	1.23	1.62	1.66	6.4%
Renewable Energy[7]	1.70	1.64	1.48	1.56	1.64	1.78	1.96	0.8%
Electricity	3.45	3.43	3.34	3.50	3.48	3.54	3.67	0.3%
Delivered Energy	**25.33**	**25.29**	**23.83**	**24.79**	**24.73**	**25.60**	**26.33**	**0.2%**
Electricity Related Losses	7.48	7.49	7.27	7.45	7.36	7.32	7.55	0.0%
Total	**32.81**	**32.77**	**31.10**	**32.24**	**32.09**	**32.93**	**33.87**	**0.1%**

Table A2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Transportation								
Liquefied Petroleum Gases	0.02	0.02	0.01	0.01	0.01	0.01	0.02	-0.2%
E85[8]	0.00	0.00	0.00	0.35	0.85	1.70	2.18	37.1%
Motor Gasoline[2]	17.22	17.29	16.93	16.25	15.56	14.73	14.49	-0.8%
Jet Fuel[9]	3.22	3.23	3.00	3.15	3.42	3.74	4.12	1.1%
Distillate Fuel Oil[10]	6.41	6.48	6.13	6.97	7.36	8.02	9.09	1.5%
Residual Fuel Oil	0.91	0.95	0.86	0.96	0.98	0.99	1.00	0.2%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.5%
Other Petroleum[11]	0.18	0.17	0.17	0.18	0.18	0.18	0.18	0.3%
Liquid Fuels and Other Petroleum Subtotal	27.96	28.14	27.11	27.87	28.36	29.38	31.09	0.4%
Pipeline Fuel Natural Gas	0.60	0.64	0.64	0.65	0.69	0.73	0.72	0.5%
Compressed Natural Gas	0.02	0.02	0.03	0.05	0.07	0.08	0.09	5.8%
Electricity	0.02	0.02	0.02	0.03	0.03	0.04	0.05	3.7%
Delivered Energy	**28.60**	**28.82**	**27.81**	**28.60**	**29.15**	**30.23**	**31.94**	**0.4%**
Electricity Related Losses	0.05	0.05	0.05	0.06	0.07	0.09	0.10	3.4%
Total	**28.65**	**28.87**	**27.86**	**28.66**	**29.22**	**30.32**	**32.05**	**0.5%**
Delivered Energy Consumption for All Sectors								
Liquefied Petroleum Gases	2.93	2.95	2.61	2.55	2.39	2.34	2.29	-1.1%
E85[8]	0.00	0.00	0.00	0.35	0.85	1.70	2.18	37.1%
Motor Gasoline[2]	17.62	17.70	17.33	16.64	15.95	15.12	14.90	-0.7%
Jet Fuel[9]	3.22	3.23	3.00	3.15	3.42	3.74	4.12	1.1%
Kerosene	0.12	0.11	0.10	0.10	0.10	0.10	0.10	-0.2%
Distillate Fuel Oil	8.79	8.94	8.38	9.17	9.49	10.11	11.17	1.0%
Residual Fuel Oil	1.22	1.28	1.07	1.21	1.22	1.23	1.25	-0.1%
Petrochemical Feedstocks	1.42	1.30	1.01	1.20	1.13	1.10	1.05	-0.9%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.5%
Other Petroleum[12]	4.66	4.57	3.89	3.98	3.89	3.88	4.01	-0.6%
Liquid Fuels and Other Petroleum Subtotal	39.98	40.08	37.40	38.36	38.42	39.32	41.07	0.1%
Natural Gas	14.11	14.79	14.86	15.30	15.34	15.60	15.73	0.3%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and Plant Fuel[6]	1.16	1.20	1.27	1.25	1.33	1.44	1.47	0.9%
Pipeline Natural Gas	0.60	0.64	0.64	0.65	0.69	0.73	0.72	0.5%
Natural Gas Subtotal	15.86	16.64	16.78	17.20	17.36	17.77	17.92	0.3%
Metallurgical Coal	0.60	0.60	0.55	0.53	0.49	0.48	0.48	-1.0%
Other Coal	1.33	1.28	1.31	1.24	1.22	1.23	1.23	-0.2%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.13	0.24	0.40	0.58	- -
Net Coal Coke Imports	0.06	0.03	0.01	0.01	0.01	0.01	0.01	-3.6%
Coal Subtotal	1.99	1.91	1.87	1.91	1.97	2.12	2.30	0.8%
Biofuels Heat and Coproducts	0.30	0.40	0.75	0.95	1.23	1.62	1.66	6.4%
Renewable Energy[13]	2.21	2.19	2.03	2.14	2.24	2.39	2.58	0.7%
Electricity	12.52	12.79	12.91	13.51	14.20	14.92	15.73	0.9%
Delivered Energy	**72.87**	**74.01**	**71.74**	**74.07**	**75.42**	**78.15**	**81.26**	**0.4%**
Electricity Related Losses	27.15	27.88	28.11	28.80	30.02	30.90	32.30	0.6%
Total	**100.02**	**101.89**	**99.85**	**102.87**	**105.44**	**109.05**	**113.56**	**0.5%**
Electric Power[14]								
Distillate Fuel Oil	0.10	0.11	0.11	0.12	0.12	0.12	0.13	0.8%
Residual Fuel Oil	0.54	0.56	0.38	0.38	0.39	0.39	0.40	-1.5%
Liquid Fuels and Other Petroleum Subtotal	0.65	0.67	0.49	0.50	0.51	0.52	0.53	-1.0%
Natural Gas	6.39	7.06	6.42	6.21	6.73	7.59	7.12	0.0%
Steam Coal	20.46	20.84	21.03	21.68	22.01	22.33	24.25	0.7%
Nuclear Power	8.21	8.41	8.45	8.68	8.99	9.04	9.47	0.5%
Renewable Energy[15]	3.76	3.45	4.42	5.07	5.79	6.17	6.43	2.7%
Electricity Imports	0.06	0.11	0.08	0.06	0.06	0.05	0.10	-0.5%
Total[16]	**39.67**	**40.67**	**41.02**	**42.32**	**44.22**	**45.82**	**48.03**	**0.7%**

Table A2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	Reference Case 2006	2007	2010	2015	2020	2025	2030	Annual Growth 2007-2030 (percent)
Total Energy Consumption								
Liquefied Petroleum Gases	2.93	2.95	2.61	2.55	2.39	2.34	2.29	-1.1%
E85[8]	0.00	0.00	0.00	0.35	0.85	1.70	2.18	37.1%
Motor Gasoline[2]	17.62	17.70	17.33	16.64	15.95	15.12	14.90	-0.7%
Jet Fuel[9]	3.22	3.23	3.00	3.15	3.42	3.74	4.12	1.1%
Kerosene	0.12	0.11	0.10	0.10	0.10	0.10	0.10	-0.2%
Distillate Fuel Oil	8.89	9.05	8.49	9.29	9.61	10.23	11.31	1.0%
Residual Fuel Oil	1.77	1.84	1.45	1.59	1.60	1.62	1.64	-0.5%
Petrochemical Feedstocks	1.42	1.30	1.01	1.20	1.13	1.10	1.05	-0.9%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.5%
Other Petroleum[12]	4.66	4.57	3.89	3.98	3.89	3.88	4.01	-0.6%
Liquid Fuels and Other Petroleum Subtotal	40.63	40.75	37.89	38.86	38.93	39.84	41.60	0.1%
Natural Gas	20.50	21.86	21.29	21.50	22.07	23.19	22.86	0.2%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and Plant Fuel[6]	1.16	1.20	1.27	1.25	1.33	1.44	1.47	0.9%
Pipeline Natural Gas	0.60	0.64	0.64	0.65	0.69	0.73	0.72	0.5%
Natural Gas Subtotal	22.26	23.70	23.20	23.40	24.09	25.36	25.04	0.2%
Metallurgical Coal	0.60	0.60	0.55	0.53	0.49	0.48	0.48	-1.0%
Other Coal	21.79	22.12	22.34	22.92	23.24	23.55	25.49	0.6%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.13	0.24	0.40	0.58	- -
Net Coal Coke Imports	0.06	0.03	0.01	0.01	0.01	0.01	0.01	-3.6%
Coal Subtotal	22.46	22.74	22.91	23.59	23.98	24.45	26.56	0.7%
Nuclear Power	8.21	8.41	8.45	8.68	8.99	9.04	9.47	0.5%
Biofuels Heat and Coproducts	0.30	0.40	0.75	0.95	1.23	1.62	1.66	6.4%
Renewable Energy[17]	5.97	5.65	6.45	7.21	8.03	8.57	9.01	2.1%
Electricity Imports	0.06	0.11	0.08	0.06	0.06	0.05	0.10	-0.5%
Total	**100.02**	**101.89**	**99.85**	**102.87**	**105.44**	**109.05**	**113.56**	**0.5%**
Energy Use and Related Statistics								
Delivered Energy Use	72.87	74.01	71.74	74.07	75.42	78.15	81.26	0.4%
Total Energy Use	100.02	101.89	99.85	102.87	105.44	109.05	113.56	0.5%
Ethanol Consumed in Motor Gasoline and E85	0.47	0.56	1.08	1.39	1.66	2.16	2.47	6.6%
Population (millions)	299.57	302.41	311.37	326.70	342.61	358.87	375.12	0.9%
Gross Domestic Product (billion 2000 dollars)	11295	11524	11779	13745	15524	17591	20114	2.5%
Carbon Dioxide Emissions (million metric tons)	5906.8	5990.8	5801.4	5903.5	5982.3	6125.3	6414.4	0.3%

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol blends (10 percent or less) in motor gasoline.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes only kerosene type.
[10]Diesel fuel for on- and off- road use.
[11]Includes aviation gasoline and lubricants.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[16]Includes non-biogenic municipal waste not included above.
[17]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2006 and 2007 population and gross domestic product: IHS Global Insight Industry and Employment models, November 2008. 2006 and 2007 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2007,* DOE/EIA-0573(2007) (Washington, DC, December 2008). **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A3. Energy Prices by Sector and Source
(2007 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Residential								
Liquefied Petroleum Gases	23.88	24.98	25.86	32.23	32.88	33.43	35.11	1.5%
Distillate Fuel Oil	18.46	19.66	18.69	23.59	24.10	24.84	26.67	1.3%
Natural Gas	13.70	12.69	12.09	11.98	12.50	13.07	14.31	0.5%
Electricity	31.21	31.19	30.89	31.77	32.72	34.05	35.84	0.6%
Commercial								
Liquefied Petroleum Gases	21.20	23.04	22.69	29.00	29.60	30.12	31.77	1.4%
Distillate Fuel Oil	15.02	16.05	16.15	21.64	22.11	23.06	24.69	1.9%
Residual Fuel Oil	8.88	10.21	10.97	16.12	16.68	17.07	17.98	2.5%
Natural Gas	11.90	10.99	10.55	10.57	11.13	11.74	12.96	0.7%
Electricity	28.38	28.07	27.29	27.13	28.15	29.23	31.01	0.4%
Industrial[1]								
Liquefied Petroleum Gases	21.04	23.38	21.84	28.19	28.78	29.35	30.99	1.2%
Distillate Fuel Oil	15.74	16.82	16.01	22.10	22.56	23.68	25.19	1.8%
Residual Fuel Oil	9.21	10.49	15.38	20.43	20.94	21.43	22.73	3.4%
Natural Gas[2]	7.96	7.52	6.91	7.01	7.48	7.99	9.07	0.8%
Metallurgical Coal	3.64	3.61	4.37	4.40	4.40	4.55	4.41	0.9%
Other Industrial Coal	2.40	2.43	2.54	2.57	2.53	2.57	2.67	0.4%
Coal to Liquids	- -	- -	- -	1.21	1.23	1.31	1.36	- -
Electricity	18.41	18.63	18.72	18.33	19.06	20.09	21.59	0.6%
Transportation								
Liquefied Petroleum Gases[3]	22.30	25.01	25.67	32.03	32.62	33.13	34.77	1.4%
E85[4]	25.51	26.67	25.47	25.51	29.30	29.75	30.10	0.5%
Motor Gasoline[5]	21.78	22.98	23.47	28.74	29.75	30.67	32.10	1.5%
Jet Fuel[6]	15.24	16.10	16.03	21.48	22.15	22.98	24.63	1.9%
Diesel Fuel (distillate fuel oil)[7]	20.27	20.92	20.05	25.74	26.04	27.16	28.59	1.4%
Residual Fuel Oil	8.21	9.35	12.10	17.08	17.46	18.13	19.65	3.3%
Natural Gas[8]	16.04	15.46	14.90	14.72	14.90	15.28	16.24	0.2%
Electricity	30.39	30.64	30.34	30.17	29.48	31.63	34.15	0.5%
Electric Power[9]								
Distillate Fuel Oil	13.77	14.77	15.09	19.90	20.45	21.28	23.11	2.0%
Residual Fuel Oil	8.38	8.38	13.21	18.19	18.55	19.26	20.67	4.0%
Natural Gas	7.05	7.02	6.59	6.72	7.15	7.73	8.70	0.9%
Steam Coal	1.74	1.78	1.89	1.94	1.92	1.96	2.04	0.6%
Average Price to All Users[10]								
Liquefied Petroleum Gases	15.66	18.53	20.96	26.83	27.56	28.13	29.77	2.1%
E85[4]	25.51	26.67	25.47	25.51	29.30	29.75	30.10	0.5%
Motor Gasoline[5]	21.65	22.82	23.47	28.74	29.75	30.67	32.10	1.5%
Jet Fuel	15.24	16.10	16.03	21.48	22.15	22.98	24.63	1.9%
Distillate Fuel Oil	19.17	19.94	18.98	24.89	25.28	26.42	27.94	1.5%
Residual Fuel Oil	8.42	9.25	12.66	17.64	18.03	18.67	20.12	3.4%
Natural Gas	9.50	9.01	8.56	8.64	9.11	9.61	10.75	0.8%
Metallurgical Coal	3.64	3.61	4.37	4.40	4.40	4.55	4.41	0.9%
Other Coal	1.78	1.82	1.93	1.98	1.95	1.99	2.07	0.6%
Coal to Liquids	- -	- -	- -	1.21	1.23	1.31	1.36	- -
Electricity	26.68	26.70	26.42	26.53	27.57	28.81	30.56	0.6%
Non-Renewable Energy Expenditures by Sector (billion 2007 dollars)								
Residential	231.09	238.38	235.27	246.49	263.30	282.96	310.03	1.1%
Commercial	170.28	173.09	172.88	186.98	207.76	228.67	256.75	1.7%
Industrial	216.13	226.84	204.25	244.30	242.68	253.34	276.26	0.9%
Transportation	564.63	596.75	580.97	735.45	752.82	779.67	853.25	1.6%
Total Non-Renewable Expenditures	1182.13	1235.06	1193.36	1413.22	1466.55	1544.64	1696.29	1.4%
Transportation Renewable Expenditures	0.03	0.04	0.07	8.97	24.83	50.69	65.71	37.9%
Total Expenditures	**1182.16**	**1235.10**	**1193.43**	**1422.19**	**1491.38**	**1595.33**	**1762.00**	**1.6%**

Table A3. Energy Prices by Sector and Source (Continued)
(Nominal Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Residential								
Liquefied Petroleum Gases	23.26	24.98	27.24	37.30	42.47	46.13	50.90	3.1%
Distillate Fuel Oil	17.98	19.66	19.68	27.29	31.14	34.28	38.67	3.0%
Natural Gas	13.34	12.69	12.74	13.86	16.14	18.03	20.75	2.2%
Electricity	30.39	31.19	32.53	36.77	42.26	46.98	51.96	2.2%
Commercial								
Liquefied Petroleum Gases	20.64	23.04	23.89	33.55	38.24	41.56	46.06	3.1%
Distillate Fuel Oil	14.63	16.05	17.01	25.03	28.56	31.82	35.80	3.5%
Residual Fuel Oil	8.65	10.21	11.55	18.65	21.55	23.55	26.07	4.2%
Natural Gas	11.58	10.99	11.11	12.22	14.37	16.20	18.78	2.4%
Electricity	27.63	28.07	28.74	31.39	36.37	40.33	44.96	2.1%
Industrial[1]								
Liquefied Petroleum Gases	20.49	23.38	23.00	32.62	37.17	40.49	44.93	2.9%
Distillate Fuel Oil	15.32	16.82	16.86	25.57	29.14	32.67	36.52	3.4%
Residual Fuel Oil	8.97	10.49	16.20	23.64	27.05	29.57	32.95	5.1%
Natural Gas[2]	7.75	7.52	7.27	8.11	9.66	11.03	13.16	2.5%
Metallurgical Coal	3.54	3.61	4.60	5.09	5.69	6.28	6.40	2.5%
Other Industrial Coal	2.34	2.43	2.67	2.98	3.27	3.55	3.88	2.0%
Coal to Liquids	- -	- -	- -	1.40	1.59	1.81	1.98	- -
Electricity	17.93	18.63	19.72	21.20	24.63	27.71	31.30	2.3%
Transportation								
Liquefied Petroleum Gases[3]	21.71	25.01	27.04	37.06	42.13	45.70	50.41	3.1%
E85[4]	24.84	26.67	26.83	29.51	37.85	41.04	43.63	2.2%
Motor Gasoline[5]	21.21	22.98	24.72	33.26	38.43	42.32	46.54	3.1%
Jet Fuel[6]	14.84	16.10	16.89	24.86	28.62	31.70	35.70	3.5%
Diesel Fuel (distillate fuel oil)[7]	19.74	20.92	21.12	29.78	33.63	37.48	41.44	3.0%
Residual Fuel Oil	7.99	9.35	12.74	19.76	22.56	25.02	28.49	5.0%
Natural Gas[8]	15.62	15.46	15.69	17.03	19.24	21.08	23.55	1.8%
Electricity	29.59	30.64	31.95	34.91	38.09	43.63	49.51	2.1%
Electric Power[9]								
Distillate Fuel Oil	13.41	14.77	15.89	23.03	26.42	29.36	33.51	3.6%
Residual Fuel Oil	8.16	8.38	13.91	21.05	23.97	26.57	29.97	5.7%
Natural Gas	6.87	7.02	6.94	7.77	9.24	10.67	12.61	2.6%
Steam Coal	1.69	1.78	1.99	2.25	2.48	2.70	2.95	2.2%

Table A3. Energy Prices by Sector and Source (Continued)
(Nominal Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Average Price to All Users[10]								
Liquefied Petroleum Gases	15.25	18.53	22.07	31.04	35.61	38.82	43.16	3.7%
E85[4]	24.84	26.67	26.83	29.51	37.85	41.04	43.63	2.2%
Motor Gasoline[5]	21.08	22.82	24.71	33.25	38.43	42.31	46.54	3.1%
Jet Fuel	14.84	16.10	16.89	24.86	28.62	31.70	35.70	3.5%
Distillate Fuel Oil	18.67	19.94	19.99	28.80	32.65	36.45	40.51	3.1%
Residual Fuel Oil	8.20	9.25	13.34	20.41	23.29	25.76	29.16	5.1%
Natural Gas	9.25	9.01	9.01	10.00	11.77	13.26	15.58	2.4%
Metallurgical Coal	3.54	3.61	4.60	5.09	5.69	6.28	6.40	2.5%
Other Coal	1.73	1.82	2.04	2.29	2.52	2.75	3.00	2.2%
Coal to Liquids	- -	- -	- -	1.40	1.59	1.81	1.98	- -
Electricity	25.98	26.70	27.82	30.69	35.62	39.75	44.31	2.2%
Non-Renewable Energy Expenditures by Sector (billion nominal dollars)								
Residential	225.03	238.38	247.78	285.21	340.12	390.39	449.49	2.8%
Commercial	165.82	173.09	182.07	216.35	268.38	315.48	372.25	3.4%
Industrial	210.46	226.84	215.12	282.68	313.49	349.53	400.54	2.5%
Transportation	549.82	596.75	611.87	850.99	972.48	1075.67	1237.08	3.2%
Total Non-Renewable Expenditures	1151.12	1235.06	1256.84	1635.24	1894.47	2131.06	2459.36	3.0%
Transportation Renewable Expenditures	0.03	0.04	0.07	10.38	32.08	69.93	95.27	40.1%
Total Expenditures	**1151.15**	**1235.10**	**1256.91**	**1645.62**	**1926.55**	**2201.00**	**2554.63**	**3.2%**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Excludes use for lease and plant fuel.
[3]Includes Federal and State taxes while excluding county and local taxes.
[4]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[5]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[8]Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[9]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[10]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 2007*, DOE/EIA-0487(2007) (Washington, DC, August 2008). 2006 residential and commercial natural gas delivered prices: EIA,*Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007). 2007 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2006 and 2007 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007) and the *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2006 transportation sector natural gas delivered prices are based on: EIA, *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007) and estimated State taxes, Federal taxes, and dispensing costs or charges. 2007 transportation sector natural gas delivered prices are model results. 2006 and 2007 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2007 and April 2008, Table 4.13.B. 2006 and 2007 coal prices based on: EIA, *Quarterly Coal Report, October-December 2007*, DOE/EIA-0121(2007/4Q) (Washington, DC, March 2008) and EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A. 2006 and 2007 electricity prices: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2006 and 2007 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A4. Residential Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Key Indicators								
Households (millions)								
Single-Family	80.80	81.74	83.61	88.69	93.63	97.66	101.57	0.9%
Multifamily	24.81	25.15	25.97	27.39	29.17	30.73	32.47	1.1%
Mobile Homes	6.89	6.85	6.73	6.75	6.96	7.03	7.09	0.2%
Total	**112.50**	**113.74**	**116.30**	**122.82**	**129.76**	**135.42**	**141.14**	**0.9%**
Average House Square Footage	**1648**	**1663**	**1701**	**1772**	**1834**	**1887**	**1934**	**0.7%**
Energy Intensity								
(million Btu per household)								
Delivered Energy Consumption	95.7	100.2	98.4	93.8	91.4	89.7	87.6	-0.6%
Total Energy Consumption	184.6	191.3	188.2	178.1	174.7	172.2	170.4	-0.5%
(thousand Btu per square foot)								
Delivered Energy Consumption	58.1	60.3	57.8	52.9	49.8	47.5	45.3	-1.2%
Total Energy Consumption	112.0	115.0	110.6	100.5	95.2	91.2	88.1	-1.2%
Delivered Energy Consumption by Fuel								
Electricity								
Space Heating	0.26	0.28	0.29	0.30	0.31	0.31	0.31	0.4%
Space Cooling	0.84	0.89	0.86	0.90	0.97	1.03	1.10	0.9%
Water Heating	0.42	0.42	0.42	0.44	0.48	0.50	0.50	0.8%
Refrigeration	0.39	0.39	0.37	0.37	0.39	0.40	0.42	0.4%
Cooking	0.10	0.11	0.11	0.12	0.13	0.13	0.14	1.3%
Clothes Dryers	0.27	0.27	0.27	0.28	0.29	0.30	0.32	0.7%
Freezers	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.4%
Lighting	0.74	0.73	0.71	0.59	0.55	0.53	0.52	-1.5%
Clothes Washers[1]	0.04	0.03	0.03	0.03	0.03	0.03	0.03	-0.9%
Dishwashers[1]	0.10	0.10	0.09	0.10	0.10	0.11	0.12	0.8%
Color Televisions and Set-Top Boxes	0.34	0.36	0.40	0.41	0.44	0.49	0.56	1.9%
Personal Computers and Related Equipment	0.14	0.15	0.18	0.19	0.20	0.21	0.23	1.7%
Furnace Fans and Boiler Circulation Pumps	0.11	0.13	0.13	0.14	0.15	0.16	0.16	1.1%
Other Uses[2]	0.78	0.82	0.85	0.92	1.01	1.10	1.19	1.7%
Delivered Energy	**4.61**	**4.75**	**4.80**	**4.85**	**5.12**	**5.39**	**5.69**	**0.8%**
Natural Gas								
Space Heating	2.85	3.21	3.27	3.34	3.39	3.42	3.40	0.3%
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Water Heating	1.35	1.35	1.35	1.37	1.40	1.39	1.35	-0.0%
Cooking	0.22	0.22	0.22	0.23	0.24	0.25	0.26	0.7%
Clothes Dryers	0.07	0.07	0.07	0.07	0.06	0.06	0.06	-0.9%
Delivered Energy	**4.49**	**4.86**	**4.92**	**5.01**	**5.10**	**5.13**	**5.07**	**0.2%**
Distillate Fuel Oil								
Space Heating	0.59	0.66	0.62	0.57	0.53	0.50	0.46	-1.6%
Water Heating	0.12	0.12	0.10	0.08	0.06	0.06	0.05	-3.7%
Delivered Energy	**0.71**	**0.78**	**0.72**	**0.64**	**0.60**	**0.55**	**0.51**	**-1.8%**
Liquefied Petroleum Gases								
Space Heating	0.20	0.22	0.21	0.20	0.20	0.20	0.19	-0.6%
Water Heating	0.10	0.09	0.08	0.06	0.06	0.05	0.05	-2.5%
Cooking	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.6%
Other Uses[3]	0.15	0.15	0.16	0.18	0.20	0.22	0.24	1.9%
Delivered Energy	**0.49**	**0.50**	**0.49**	**0.48**	**0.49**	**0.50**	**0.52**	**0.2%**
Marketed Renewables (wood)[4]	0.39	0.43	0.43	0.46	0.48	0.49	0.50	0.7%
Other Fuels[5]	0.08	0.09	0.08	0.08	0.08	0.08	0.08	-0.5%

Table A4. Residential Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Delivered Energy Consumption by End Use								
Space Heating	4.37	4.89	4.91	4.95	4.99	4.99	4.95	0.1%
Space Cooling	0.84	0.89	0.86	0.90	0.97	1.03	1.10	0.9%
Water Heating	1.99	1.98	1.95	1.95	2.00	2.01	1.95	-0.1%
Refrigeration	0.39	0.39	0.37	0.37	0.39	0.40	0.42	0.4%
Cooking	0.35	0.36	0.37	0.38	0.41	0.42	0.43	0.9%
Clothes Dryers	0.34	0.34	0.34	0.34	0.35	0.36	0.38	0.4%
Freezers	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.4%
Lighting	0.74	0.73	0.71	0.59	0.55	0.53	0.52	-1.5%
Clothes Washers[1]	0.04	0.03	0.03	0.03	0.03	0.03	0.03	-0.9%
Dishwashers[1]	0.10	0.10	0.09	0.10	0.10	0.11	0.12	0.8%
Color Televisions and Set-Top Boxes	0.34	0.36	0.40	0.41	0.44	0.49	0.56	1.9%
Personal Computers and Related Equipment	0.14	0.15	0.18	0.19	0.20	0.21	0.23	1.7%
Furnace Fans and Boiler Circulation Pumps	0.11	0.13	0.13	0.14	0.15	0.16	0.16	1.1%
Other Uses[6]	0.94	0.97	1.01	1.09	1.21	1.32	1.43	1.7%
Delivered Energy	**10.77**	**11.40**	**11.44**	**11.52**	**11.86**	**12.14**	**12.36**	**0.4%**
Electricity Related Losses	**10.00**	**10.36**	**10.44**	**10.35**	**10.81**	**11.17**	**11.69**	**0.5%**
Total Energy Consumption by End Use								
Space Heating	4.94	5.51	5.53	5.58	5.64	5.63	5.59	0.1%
Space Cooling	2.65	2.82	2.73	2.82	3.01	3.17	3.34	0.7%
Water Heating	2.89	2.90	2.87	2.88	3.01	3.05	2.98	0.1%
Refrigeration	1.24	1.23	1.18	1.16	1.20	1.23	1.29	0.2%
Cooking	0.58	0.59	0.60	0.63	0.67	0.70	0.72	0.9%
Clothes Dryers	0.92	0.92	0.92	0.94	0.96	0.98	1.03	0.5%
Freezers	0.26	0.26	0.25	0.25	0.26	0.27	0.28	0.3%
Lighting	2.35	2.33	2.27	1.85	1.73	1.63	1.59	-1.6%
Clothes Washers[1]	0.11	0.11	0.10	0.09	0.08	0.08	0.09	-1.1%
Dishwashers[1]	0.30	0.30	0.30	0.30	0.32	0.33	0.35	0.7%
Color Televisions and Set-Top Boxes	1.07	1.15	1.28	1.29	1.37	1.51	1.71	1.8%
Personal Computers and Related Equipment	0.45	0.49	0.58	0.58	0.61	0.65	0.69	1.5%
Furnace Fans and Boiler Circulation Pumps	0.36	0.41	0.42	0.44	0.47	0.49	0.50	0.9%
Other Uses[6]	2.63	2.75	2.85	3.05	3.34	3.60	3.88	1.5%
Total	**20.77**	**21.76**	**21.88**	**21.87**	**22.67**	**23.31**	**24.05**	**0.4%**
Nonmarketed Renewables[7]								
Geothermal Heat Pumps	0.00	0.00	0.00	0.01	0.01	0.02	0.02	9.1%
Solar Hot Water Heating	0.00	0.00	0.00	0.00	0.00	0.01	0.01	2.6%
Solar Photovoltaic	0.00	0.00	0.01	0.03	0.05	0.05	0.05	25.2%
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0%
Total	**0.01**	**0.01**	**0.01**	**0.05**	**0.07**	**0.07**	**0.08**	**11.5%**

[1]Does not include water heating portion of load.
[2]Includes small electric devices, heating elements, and motors not listed above.
[3]Includes such appliances as outdoor grills and mosquito traps.
[4]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 2005*.
[5]Includes kerosene and coal.
[6]Includes all other uses listed above.
[7]Represents delivered energy displaced.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 based on: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A5. Commercial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Key Indicators								
Total Floorspace (billion square feet)								
Surviving	73.7	75.2	79.5	84.2	90.3	95.6	101.2	1.3%
New Additions	2.1	2.1	1.7	1.9	1.9	1.9	2.1	-0.1%
Total	**75.8**	**77.3**	**81.2**	**86.1**	**92.3**	**97.5**	**103.3**	**1.3%**
Energy Consumption Intensity (thousand Btu per square foot)								
Delivered Energy Consumption	107.9	110.0	106.7	106.3	105.0	104.3	102.9	-0.3%
Electricity Related Losses	126.9	129.3	127.5	127.1	127.6	126.3	125.5	-0.1%
Total Energy Consumption	234.8	239.3	234.2	233.4	232.6	230.7	228.4	-0.2%
Delivered Energy Consumption by Fuel								
Purchased Electricity								
Space Heating[1]	0.16	0.17	0.17	0.17	0.18	0.18	0.18	0.2%
Space Cooling[1]	0.53	0.56	0.54	0.57	0.60	0.62	0.65	0.7%
Water Heating[1]	0.10	0.10	0.09	0.10	0.10	0.10	0.10	-0.1%
Ventilation	0.48	0.49	0.53	0.59	0.64	0.68	0.71	1.6%
Cooking	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.1%
Lighting	1.08	1.07	1.06	1.10	1.15	1.19	1.22	0.5%
Refrigeration	0.40	0.40	0.40	0.38	0.38	0.39	0.40	-0.0%
Office Equipment (PC)	0.21	0.24	0.25	0.27	0.29	0.32	0.34	1.5%
Office Equipment (non-PC)	0.19	0.21	0.26	0.32	0.38	0.41	0.43	3.2%
Other Uses[2]	1.27	1.31	1.43	1.61	1.83	2.04	2.27	2.4%
Delivered Energy	**4.43**	**4.58**	**4.75**	**5.14**	**5.57**	**5.95**	**6.31**	**1.4%**
Natural Gas								
Space Heating[1]	1.35	1.45	1.50	1.54	1.56	1.56	1.53	0.2%
Space Cooling[1]	0.04	0.04	0.04	0.04	0.04	0.04	0.04	-0.2%
Water Heating[1]	0.44	0.44	0.44	0.47	0.51	0.54	0.56	1.0%
Cooking	0.16	0.16	0.18	0.19	0.20	0.21	0.22	1.2%
Other Uses[3]	0.94	1.00	0.99	1.01	1.04	1.10	1.19	0.7%
Delivered Energy	**2.92**	**3.10**	**3.14**	**3.25**	**3.34**	**3.45**	**3.54**	**0.6%**
Distillate Fuel Oil								
Space Heating[1]	0.15	0.17	0.16	0.15	0.15	0.15	0.15	-0.5%
Water Heating[1]	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.9%
Other Uses[4]	0.22	0.22	0.18	0.17	0.17	0.17	0.17	-1.2%
Delivered Energy	**0.40**	**0.41**	**0.36**	**0.34**	**0.34**	**0.34**	**0.34**	**-0.8%**
Marketed Renewables (biomass)	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.0%
Other Fuels[5]	0.29	0.29	0.28	0.30	0.31	0.31	0.31	0.3%
Delivered Energy Consumption by End Use								
Space Heating[1]	1.66	1.79	1.83	1.86	1.89	1.89	1.86	0.2%
Space Cooling[1]	0.57	0.59	0.58	0.61	0.63	0.66	0.69	0.6%
Water Heating[1]	0.56	0.56	0.55	0.59	0.63	0.66	0.68	0.9%
Ventilation	0.48	0.49	0.53	0.59	0.64	0.68	0.71	1.6%
Cooking	0.18	0.19	0.20	0.21	0.22	0.23	0.24	1.1%
Lighting	1.08	1.07	1.06	1.10	1.15	1.19	1.22	0.5%
Refrigeration	0.40	0.40	0.40	0.38	0.38	0.39	0.40	-0.0%
Office Equipment (PC)	0.21	0.24	0.25	0.27	0.29	0.32	0.34	1.5%
Office Equipment (non-PC)	0.19	0.21	0.26	0.32	0.38	0.41	0.43	3.2%
Other Uses[6]	2.84	2.95	3.00	3.22	3.47	3.74	4.06	1.4%
Delivered Energy	**8.17**	**8.50**	**8.66**	**9.15**	**9.69**	**10.17**	**10.62**	**1.0%**

Table A5. Commercial Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Electricity Related Losses	**9.62**	**9.99**	**10.35**	**10.95**	**11.77**	**12.32**	**12.96**	**1.1%**
Total Energy Consumption by End Use								
Space Heating[1]	2.01	2.16	2.20	2.23	2.27	2.26	2.23	0.1%
Space Cooling[1]	1.73	1.80	1.77	1.82	1.89	1.95	2.03	0.5%
Water Heating[1]	0.77	0.77	0.76	0.80	0.83	0.86	0.87	0.6%
Ventilation	1.51	1.57	1.68	1.85	2.01	2.10	2.17	1.4%
Cooking	0.24	0.24	0.25	0.26	0.27	0.28	0.29	0.8%
Lighting	3.41	3.41	3.36	3.44	3.58	3.64	3.71	0.4%
Refrigeration	1.26	1.28	1.26	1.18	1.18	1.19	1.22	-0.2%
Office Equipment (PC)	0.68	0.77	0.80	0.85	0.91	0.98	1.03	1.3%
Office Equipment (non-PC)	0.61	0.67	0.82	1.00	1.18	1.26	1.32	3.0%
Other Uses[6]	5.59	5.82	6.11	6.66	7.33	7.96	8.71	1.8%
Total	**17.79**	**18.49**	**19.01**	**20.10**	**21.46**	**22.49**	**23.59**	**1.1%**
Nonmarketed Renewable Fuels[7]								
Solar Thermal	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.5%
Solar Photovoltaic	0.00	0.00	0.00	0.01	0.01	0.01	0.01	8.4%
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.3%
Total	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**2.0%**

[1]Includes fuel consumption for district services.
[2]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, and medical equipment.
[3]Includes miscellaneous uses, such as pumps, emergency generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, emergency generators, and combined heat and power in commercial buildings.
[5]Includes residual fuel oil, liquefied petroleum gases, coal, motor gasoline, and kerosene.
[6]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, emergency generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gases, coal, motor gasoline, and kerosene.
[7]Represents delivered energy displaced by solar thermal space heating and water heating, and electricity generation by solar photovoltaic systems.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 based on: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A6. Industrial Sector Key Indicators and Consumption

Key Indicators and Consumption	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Key Indicators								
Value of Shipments (billion 2000 dollars)								
Manufacturing	4260	4261	3963	4694	5150	5732	6671	2.0%
Nonmanufacturing	1503	1490	1277	1581	1603	1671	1780	0.8%
Total	**5763**	**5750**	**5240**	**6276**	**6753**	**7402**	**8451**	**1.7%**
Energy Prices								
(2007 dollars per million Btu)								
Liquefied Petroleum Gases	21.04	23.38	21.84	28.19	28.78	29.35	30.99	1.2%
Motor Gasoline	15.92	15.93	23.41	28.63	29.64	30.58	32.04	3.1%
Distillate Fuel Oil	15.74	16.82	16.01	22.10	22.56	23.68	25.19	1.8%
Residual Fuel Oil	9.21	10.49	15.38	20.43	20.94	21.43	22.73	3.4%
Petrochemical Feedstocks	9.26	12.60	12.09	17.06	17.63	18.09	18.95	1.8%
Asphalt and Road Oil	4.75	5.36	6.49	9.30	9.52	9.87	10.70	3.1%
Natural Gas Heat and Power	6.94	6.59	6.03	6.18	6.65	7.18	8.31	1.0%
Natural Gas Feedstocks	8.71	8.24	7.70	7.80	8.25	8.76	9.83	0.8%
Metallurgical Coal	3.64	3.61	4.37	4.40	4.40	4.55	4.41	0.9%
Other Industrial Coal	2.40	2.43	2.54	2.57	2.53	2.57	2.67	0.4%
Coal for Liquids	- -	- -	- -	1.21	1.23	1.31	1.36	- -
Electricity	18.41	18.63	18.72	18.33	19.06	20.09	21.59	0.6%
(nominal dollars per million Btu)								
Liquefied Petroleum Gases	20.49	23.38	23.00	32.62	37.17	40.49	44.93	2.9%
Motor Gasoline	15.51	15.93	24.66	33.13	38.29	42.19	46.45	4.8%
Distillate Fuel Oil	15.32	16.82	16.86	25.57	29.14	32.67	36.52	3.4%
Residual Fuel Oil	8.97	10.49	16.20	23.64	27.05	29.57	32.95	5.1%
Petrochemical Feedstocks	9.02	12.60	12.74	19.74	22.77	24.95	27.48	3.4%
Asphalt and Road Oil	4.63	5.36	6.83	10.76	12.30	13.62	15.51	4.7%
Natural Gas Heat and Power	6.76	6.59	6.35	7.15	8.59	9.91	12.05	2.7%
Natural Gas Feedstocks	8.48	8.24	8.11	9.02	10.66	12.09	14.26	2.4%
Metallurgical Coal	3.54	3.61	4.60	5.09	5.69	6.28	6.40	2.5%
Other Industrial Coal	2.34	2.43	2.67	2.98	3.27	3.55	3.88	2.0%
Coal for Liquids	- -	- -	- -	1.40	1.59	1.81	1.98	- -
Electricity	17.93	18.63	19.72	21.20	24.63	27.71	31.30	2.3%
Energy Consumption (quadrillion Btu)[1]								
Industrial Consumption Excluding Refining								
Liquefied Petroleum Gases Heat and Power	0.17	0.18	0.15	0.16	0.15	0.15	0.16	-0.6%
Liquefied Petroleum Gases Feedstocks	2.16	2.16	1.83	1.80	1.61	1.57	1.50	-1.6%
Motor Gasoline	0.36	0.36	0.34	0.35	0.34	0.34	0.36	-0.1%
Distillate Fuel Oil	1.26	1.27	1.17	1.21	1.18	1.19	1.23	-0.1%
Residual Fuel Oil	0.23	0.24	0.15	0.16	0.16	0.16	0.16	-1.7%
Petrochemical Feedstocks	1.42	1.30	1.01	1.20	1.13	1.10	1.05	-0.9%
Petroleum Coke	0.36	0.36	0.27	0.29	0.29	0.29	0.31	-0.6%
Asphalt and Road Oil	1.26	1.19	0.96	1.15	1.08	1.07	1.12	-0.3%
Miscellaneous Petroleum[2]	0.59	0.62	0.30	0.23	0.21	0.21	0.21	-4.6%
Petroleum Subtotal	7.81	7.68	6.18	6.55	6.15	6.08	6.10	-1.0%
Natural Gas Heat and Power	4.99	5.14	5.02	5.00	4.86	4.99	5.11	-0.0%
Natural Gas Feedstocks	0.58	0.55	0.51	0.52	0.50	0.49	0.44	-0.9%
Lease and Plant Fuel[3]	1.16	1.20	1.27	1.25	1.33	1.44	1.47	0.9%
Natural Gas Subtotal	6.73	6.89	6.80	6.78	6.69	6.92	7.02	0.1%
Metallurgical Coal and Coke[4]	0.66	0.62	0.56	0.55	0.50	0.49	0.49	-1.1%
Other Industrial Coal	1.19	1.15	1.18	1.10	1.09	1.10	1.10	-0.2%
Coal Subtotal	1.86	1.77	1.74	1.65	1.60	1.59	1.59	-0.5%
Renewables[5]	1.70	1.64	1.48	1.56	1.64	1.78	1.96	0.8%
Purchased Electricity	3.30	3.27	3.15	3.29	3.27	3.32	3.45	0.2%
Delivered Energy	**21.39**	**21.26**	**19.36**	**19.83**	**19.35**	**19.68**	**20.11**	**-0.2%**
Electricity Related Losses	7.16	7.13	6.86	7.01	6.91	6.88	7.09	-0.0%
Total	**28.55**	**28.40**	**26.22**	**26.83**	**26.25**	**26.57**	**27.20**	**-0.2%**

Table A6. Industrial Sector Key Indicators and Consumption (Continued)

Key Indicators and Consumption	Reference Case 2006	2007	2010	2015	2020	2025	2030	Annual Growth 2007-2030 (percent)
Refining Consumption								
Liquefied Petroleum Gases Heat and Power	0.01	0.01	0.03	0.01	0.02	0.00	0.00	- -
Distillate Fuel Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Residual Fuel Oil	0.01	0.01	0.00	0.00	0.00	0.00	0.00	- -
Petroleum Coke	0.57	0.55	0.54	0.54	0.53	0.52	0.53	-0.2%
Still Gas	1.69	1.68	1.65	1.60	1.62	1.62	1.67	-0.0%
Miscellaneous Petroleum[2]	0.04	0.02	0.01	0.01	0.01	0.01	0.01	-4.8%
Petroleum Subtotal	2.32	2.27	2.24	2.16	2.17	2.15	2.20	-0.1%
Natural Gas Heat and Power	1.10	1.13	1.25	1.46	1.47	1.47	1.49	1.2%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural Gas Subtotal	1.10	1.13	1.25	1.46	1.47	1.47	1.49	1.2%
Other Industrial Coal	0.06	0.06	0.06	0.06	0.06	0.06	0.06	-0.2%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.13	0.24	0.40	0.58	- -
Coal Subtotal	0.06	0.06	0.06	0.19	0.30	0.46	0.64	10.7%
Biofuels Heat and Coproducts	0.30	0.40	0.75	0.95	1.23	1.62	1.66	6.4%
Purchased Electricity	0.15	0.16	0.19	0.21	0.22	0.21	0.22	1.4%
Delivered Energy	**3.94**	**4.03**	**4.48**	**4.97**	**5.38**	**5.92**	**6.22**	**1.9%**
Electricity Related Losses	0.32	0.35	0.41	0.44	0.46	0.44	0.46	1.2%
Total	**4.25**	**4.38**	**4.88**	**5.41**	**5.84**	**6.36**	**6.67**	**1.9%**
Total Industrial Sector Consumption								
Liquefied Petroleum Gases Heat and Power	0.18	0.19	0.19	0.17	0.17	0.15	0.16	-0.8%
Liquefied Petroleum Gases Feedstocks	2.16	2.16	1.83	1.80	1.61	1.57	1.50	-1.6%
Motor Gasoline	0.36	0.36	0.34	0.35	0.34	0.34	0.36	-0.1%
Distillate Fuel Oil	1.26	1.28	1.17	1.21	1.18	1.19	1.23	-0.1%
Residual Fuel Oil	0.24	0.25	0.15	0.16	0.16	0.16	0.16	-1.9%
Petrochemical Feedstocks	1.42	1.30	1.01	1.20	1.13	1.10	1.05	-0.9%
Petroleum Coke	0.93	0.91	0.81	0.83	0.82	0.82	0.83	-0.4%
Asphalt and Road Oil	1.26	1.19	0.96	1.15	1.08	1.07	1.12	-0.3%
Still Gas	1.69	1.68	1.65	1.60	1.62	1.62	1.67	-0.0%
Miscellaneous Petroleum[2]	0.63	0.65	0.31	0.23	0.21	0.22	0.22	-4.6%
Petroleum Subtotal	10.13	9.96	8.42	8.71	8.32	8.22	8.30	-0.8%
Natural Gas Heat and Power	6.10	6.27	6.27	6.47	6.34	6.46	6.60	0.2%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural Gas Feedstocks	0.58	0.55	0.51	0.52	0.50	0.49	0.44	-0.9%
Lease and Plant Fuel[3]	1.16	1.20	1.27	1.25	1.33	1.44	1.47	0.9%
Natural Gas Subtotal	7.83	8.02	8.05	8.24	8.17	8.39	8.51	0.3%
Metallurgical Coal and Coke[4]	0.66	0.62	0.56	0.55	0.50	0.49	0.49	-1.1%
Other Industrial Coal	1.25	1.21	1.24	1.16	1.15	1.16	1.16	-0.2%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.13	0.24	0.40	0.58	32.7%
Coal Subtotal	1.92	1.83	1.80	1.84	1.89	2.05	2.23	0.9%
Biofuels Heat and Coproducts	0.30	0.40	0.75	0.95	1.23	1.62	1.66	6.4%
Renewables[5]	1.70	1.64	1.48	1.56	1.64	1.78	1.96	0.8%
Purchased Electricity	3.45	3.43	3.34	3.50	3.48	3.54	3.67	0.3%
Delivered Energy	**25.33**	**25.29**	**23.83**	**24.79**	**24.73**	**25.60**	**26.33**	**0.2%**
Electricity Related Losses	7.48	7.49	7.27	7.45	7.36	7.32	7.55	0.0%
Total	**32.81**	**32.77**	**31.10**	**32.24**	**32.09**	**32.93**	**33.87**	**0.1%**

Table A6. Industrial Sector Key Indicators and Consumption (Continued)

Key Indicators and Consumption	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Energy Consumption per dollar of Shipment (thousand Btu per 2000 dollars)								
Liquefied Petroleum Gases Heat and Power	0.03	0.03	0.04	0.03	0.03	0.02	0.02	-2.4%
Liquefied Petroleum Gases Feedstocks	0.37	0.38	0.35	0.29	0.24	0.21	0.18	-3.2%
Motor Gasoline	0.06	0.06	0.07	0.06	0.05	0.05	0.04	-1.7%
Distillate Fuel Oil	0.22	0.22	0.22	0.19	0.18	0.16	0.15	-1.8%
Residual Fuel Oil	0.04	0.04	0.03	0.03	0.02	0.02	0.02	-3.5%
Petrochemical Feedstocks	0.25	0.23	0.19	0.19	0.17	0.15	0.12	-2.6%
Petroleum Coke	0.16	0.16	0.15	0.13	0.12	0.11	0.10	-2.0%
Asphalt and Road Oil	0.22	0.21	0.18	0.18	0.16	0.14	0.13	-1.9%
Still Gas	0.29	0.29	0.32	0.26	0.24	0.22	0.20	-1.7%
Miscellaneous Petroleum[2]	0.11	0.11	0.06	0.04	0.03	0.03	0.03	-6.2%
Petroleum Subtotal	1.76	1.73	1.61	1.39	1.23	1.11	0.98	-2.4%
Natural Gas Heat and Power	1.06	1.09	1.20	1.03	0.94	0.87	0.78	-1.4%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural Gas Feedstocks	0.10	0.10	0.10	0.08	0.07	0.07	0.05	-2.6%
Lease and Plant Fuel[3]	0.20	0.21	0.24	0.20	0.20	0.20	0.17	-0.8%
Natural Gas Subtotal	1.36	1.39	1.54	1.31	1.21	1.13	1.01	-1.4%
Metallurgical Coal and Coke[4]	0.12	0.11	0.11	0.09	0.07	0.07	0.06	-2.7%
Other Industrial Coal	0.22	0.21	0.24	0.19	0.17	0.16	0.14	-1.8%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.02	0.04	0.05	0.07	30.5%
Coal Subtotal	0.33	0.32	0.34	0.29	0.28	0.28	0.26	-0.8%
Biofuels Heat and Coproducts	0.05	0.07	0.14	0.15	0.18	0.22	0.20	4.6%
Renewables[5]	0.29	0.29	0.28	0.25	0.24	0.24	0.23	-0.9%
Purchased Electricity	0.60	0.60	0.64	0.56	0.52	0.48	0.43	-1.4%
Delivered Energy	**4.39**	**4.40**	**4.55**	**3.95**	**3.66**	**3.46**	**3.12**	**-1.5%**
Electricity Related Losses	1.30	1.30	1.39	1.19	1.09	0.99	0.89	-1.6%
Total	**5.69**	**5.70**	**5.94**	**5.14**	**4.75**	**4.45**	**4.01**	**-1.5%**
Industrial Combined Heat and Power								
Capacity (gigawatts)	25.69	25.42	28.84	31.46	35.01	40.93	45.71	2.6%
Generation (billion kilowatthours)	143.19	141.01	160.28	178.75	205.32	251.19	285.32	3.1%

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lubricants and miscellaneous petroleum products.
[3]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[4]Includes net coal coke imports.
[5]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources.
Btu = British thermal unit.
- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.

Sources: 2006 and 2007 prices for motor gasoline and distillate fuel oil are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2007*, DOE/EIA-0487(2007) (Washington, DC, August 2008). 2006 and 2007 petrochemical feedstock and asphalt and road oil prices are based on: EIA, *State Energy Data Report 2006*, DOE/EIA-0214(2006) (Washington, DC, October 2008). 2006 and 2007 coal prices are based on: EIA, *Quarterly Coal Report, October-December 2007*, DOE/EIA-0121(2007/4Q) (Washington, DC, March 2008) and EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A. 2006 and 2007 electricity prices: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2006 and 2007 natural gas prices are based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007) and the *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2006 refining consumption values based on: *Petroleum Supply Annual 2006,* DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). 2007 refining consumption based on: *Petroleum Supply Annual 2007,* DOE/EIA-0340(2007)/1 (Washington, DC, July 2008). Other 2006 and 2007 consumption values are based on: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2006 and 2007 shipments: IHS Global Insight industry model, November 2008. **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Key Indicators								
Travel Indicators								
(billion vehicle miles traveled)								
Light-Duty Vehicles less than 8,500 pounds	2695	2702	2747	2869	3161	3489	3827	1.5%
Commercial Light Trucks[1]	70	72	67	78	85	93	105	1.7%
Freight Trucks greater than 10,000 pounds	244	248	232	277	303	334	378	1.9%
(billion seat miles available)								
Air	984	1036	951	1018	1138	1272	1410	1.3%
(billion ton miles traveled)								
Rail	1718	1733	1664	1846	1927	2024	2193	1.0%
Domestic Shipping	659	662	629	697	744	798	839	1.0%
Energy Efficiency Indicators								
(miles per gallon)								
Tested New Light-Duty Vehicle[2]	26.2	26.3	26.9	32.6	35.5	36.8	38.0	1.6%
New Car[2]	30.2	30.3	30.7	36.6	39.1	40.2	41.4	1.4%
New Light Truck[2]	23.1	23.1	23.6	28.3	30.7	32.1	33.1	1.6%
On-Road New Light-Duty Vehicle[3]	21.4	21.8	22.3	27.1	29.5	30.8	31.9	1.7%
New Car[3]	23.8	24.6	25.1	30.1	32.3	33.5	34.7	1.5%
New Light Truck[3]	19.4	19.4	19.8	23.8	25.8	27.0	27.8	1.6%
Light-Duty Stock[4]	20.4	20.6	20.7	22.4	24.7	27.0	28.9	1.5%
New Commercial Light Truck[1]	15.5	15.4	15.7	18.6	19.6	20.0	20.3	1.2%
Stock Commercial Light Truck[1]	14.3	14.4	14.8	16.0	17.6	18.9	19.8	1.4%
Freight Truck	6.0	6.0	6.0	6.2	6.5	6.7	6.9	0.6%
(seat miles per gallon)								
Aircraft	62.2	62.8	64.4	66.2	68.1	70.4	73.6	0.7%
(ton miles per thousand Btu)								
Rail	2.9	2.9	2.9	2.9	3.0	3.0	3.0	0.1%
Domestic Shipping	2.0	2.0	2.0	2.0	2.0	2.0	2.0	0.1%
Energy Use by Mode (quadrillion Btu)								
Light-Duty Vehicles	16.42	16.47	16.20	15.86	15.80	16.02	16.51	0.0%
Commercial Light Trucks[1]	0.62	0.62	0.57	0.61	0.61	0.62	0.67	0.3%
Bus Transportation	0.27	0.27	0.27	0.27	0.27	0.27	0.28	0.2%
Freight Trucks	5.07	5.15	4.81	5.55	5.79	6.19	6.90	1.3%
Rail, Passenger	0.04	0.05	0.05	0.05	0.05	0.06	0.06	1.3%
Rail, Freight	0.59	0.59	0.57	0.63	0.65	0.68	0.73	0.9%
Shipping, Domestic	0.34	0.34	0.32	0.35	0.37	0.40	0.42	0.9%
Shipping, International	0.84	0.88	0.80	0.89	0.90	0.90	0.91	0.1%
Recreational Boats	0.25	0.25	0.25	0.26	0.26	0.27	0.28	0.4%
Air	2.71	2.71	2.45	2.62	2.87	3.18	3.54	1.2%
Military Use	0.69	0.70	0.74	0.72	0.74	0.76	0.78	0.4%
Lubricants	0.15	0.14	0.14	0.14	0.15	0.15	0.15	0.4%
Pipeline Fuel	0.60	0.64	0.64	0.65	0.69	0.73	0.72	0.5%
Total	**28.60**	**28.82**	**27.81**	**28.60**	**29.15**	**30.23**	**31.94**	**0.4%**

Table A7. Transportation Sector Key Indicators and Delivered Energy Consumption (Continued)

Key Indicators and Consumption	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Energy Use by Mode (million barrels per day oil equivalent)								
Light-Duty Vehicles	8.61	8.74	8.72	8.61	8.69	9.00	9.35	0.3%
Commercial Light Trucks[1]	0.32	0.33	0.31	0.33	0.33	0.33	0.36	0.4%
Bus Transportation	0.13	0.13	0.13	0.13	0.13	0.13	0.14	0.2%
Freight Trucks	2.42	2.46	2.30	2.66	2.77	2.96	3.31	1.3%
Rail, Passenger	0.02	0.02	0.02	0.02	0.03	0.03	0.03	1.3%
Rail, Freight	0.28	0.28	0.27	0.30	0.31	0.32	0.35	0.9%
Shipping, Domestic	0.16	0.16	0.15	0.16	0.17	0.19	0.19	0.9%
Shipping, International	0.37	0.39	0.35	0.39	0.39	0.40	0.40	0.1%
Recreational Boats	0.13	0.13	0.14	0.14	0.14	0.15	0.15	0.5%
Air	1.31	1.31	1.19	1.27	1.39	1.54	1.71	1.2%
Military Use	0.33	0.34	0.36	0.35	0.36	0.37	0.37	0.4%
Lubricants	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.4%
Pipeline Fuel	0.30	0.32	0.32	0.33	0.35	0.37	0.36	0.5%
Total	**14.46**	**14.68**	**14.32**	**14.76**	**15.13**	**15.85**	**16.80**	**0.6%**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]Environmental Protection Agency rated miles per gallon.
[3]Tested new vehicle efficiency revised for on-road performance.
[4]Combined car and light truck "on-the-road" estimate.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.

Sources: 2006 and 2007: Energy Information Administration (EIA), *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007); EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008); Federal Highway Administration, *Highway Statistics 2005* (Washington, DC, October 2006); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 27 and Annual* (Oak Ridge, TN, 2008); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, March 2004); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC97TV (Washington, DC, October 1999); EIA, Alternatives to Traditional Transportation Fuels 2006 (Part II - User and Fuel Data), May 2008; EIA, *State Energy Data Report 2006*, DOE/EIA-0214(2006) (Washington, DC, October 2008); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2007/2006* (Washington, DC, 2007); EIA, *Fuel Oil and Kerosene Sales 2006*, DOE/EIA-0535(2006) (Washington, DC, December 2007); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A8. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Generation by Fuel Type								
Electric Power Sector[1]								
Power Only[2]								
Coal	1934	1965	2006	2065	2093	2120	2334	0.8%
Petroleum	55	57	43	44	44	45	46	-0.9%
Natural Gas[3]	618	685	629	617	687	824	772	0.5%
Nuclear Power	787	806	809	831	862	867	907	0.5%
Pumped Storage/Other[4]	1	0	1	1	1	1	1	8.8%
Renewable Sources[5]	348	314	411	473	543	581	610	2.9%
Distributed Generation (Natural Gas)	0	0	0	0	0	0	0	- -
Total	**3742**	**3827**	**3899**	**4030**	**4230**	**4438**	**4670**	**0.9%**
Combined Heat and Power[6]								
Coal	36	37	32	32	32	32	32	-0.6%
Petroleum	5	5	0	0	0	0	0	-10.0%
Natural Gas	116	129	107	112	114	114	109	-0.7%
Renewable Sources	4	4	4	4	5	5	5	0.6%
Total	**165**	**179**	**143**	**148**	**151**	**151**	**146**	**-0.9%**
Total Net Generation	**3908**	**4006**	**4042**	**4178**	**4381**	**4589**	**4816**	**0.8%**
Less Direct Use	33	34	34	33	34	34	33	-0.1%
Net Available to the Grid	**3875**	**3972**	**4009**	**4145**	**4348**	**4556**	**4783**	**0.8%**
End-Use Generation[7]								
Coal	22	19	19	25	31	39	48	4.1%
Petroleum	4	4	13	13	13	14	14	5.6%
Natural Gas	77	78	78	87	97	112	131	2.3%
Other Gaseous Fuels[8]	5	5	16	15	15	15	15	5.1%
Renewable Sources[9]	34	33	36	50	69	98	116	5.6%
Other[10]	13	13	12	12	12	12	12	-0.4%
Total	**155**	**153**	**174**	**203**	**237**	**289**	**337**	**3.5%**
Less Direct Use	124	122	142	164	188	223	261	3.4%
Total Sales to the Grid	**31**	**31**	**33**	**38**	**49**	**66**	**76**	**3.9%**
Total Electricity Generation by Fuel								
Coal	1992	2021	2057	2121	2156	2191	2415	0.8%
Petroleum	64	66	56	57	58	59	60	-0.3%
Natural Gas	812	892	814	815	898	1050	1012	0.6%
Nuclear Power	787	806	809	831	862	867	907	0.5%
Renewable Sources[5,9]	386	352	451	527	617	684	730	3.2%
Other[11]	23	22	29	28	28	28	28	1.1%
Total	**4063**	**4159**	**4217**	**4381**	**4618**	**4879**	**5153**	**0.9%**
Total Electricity Generation	**4063**	**4159**	**4217**	**4381**	**4618**	**4879**	**5153**	**0.9%**
Total Net Generation to the Grid	**3906**	**4004**	**4042**	**4183**	**4396**	**4622**	**4859**	**0.8%**
Net Imports	**18**	**31**	**24**	**17**	**18**	**14**	**28**	**-0.5%**
Electricity Sales by Sector								
Residential	1352	1392	1406	1423	1499	1581	1667	0.8%
Commercial	1300	1343	1393	1505	1632	1743	1850	1.4%
Industrial	1011	1006	979	1025	1021	1036	1077	0.3%
Transportation	6	6	7	8	10	12	15	3.7%
Total	**3669**	**3747**	**3785**	**3960**	**4162**	**4373**	**4609**	**0.9%**
Direct Use	157	156	175	198	222	257	294	2.8%
Total Electricity Use	**3826**	**3903**	**3960**	**4158**	**4384**	**4629**	**4903**	**1.0%**

Table A8. Electricity Supply, Disposition, Prices, and Emissions (Continued)
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
End-Use Prices								
(2007 cents per kilowatthour)								
Residential	10.6	10.6	10.5	10.8	11.2	11.6	12.2	0.6%
Commercial	9.7	9.6	9.3	9.3	9.6	10.0	10.6	0.4%
Industrial	6.3	6.4	6.4	6.3	6.5	6.9	7.4	0.6%
Transportation	10.4	10.5	10.4	10.3	10.1	10.8	11.7	0.5%
All Sectors Average	**9.1**	**9.1**	**9.0**	**9.1**	**9.4**	**9.8**	**10.4**	**0.6%**
(nominal cents per kilowatthour)								
Residential	10.4	10.6	11.1	12.5	14.4	16.0	17.7	2.2%
Commercial	9.4	9.6	9.8	10.7	12.4	13.8	15.3	2.1%
Industrial	6.1	6.4	6.7	7.2	8.4	9.5	10.7	2.3%
Transportation	10.1	10.5	10.9	11.9	13.0	14.9	16.9	2.1%
All Sectors Average	**8.9**	**9.1**	**9.5**	**10.5**	**12.2**	**13.6**	**15.1**	**2.2%**
Prices by Service Category								
(2007 cents per kilowatthour)								
Generation	6.0	6.0	6.0	5.9	6.2	6.6	7.3	0.8%
Transmission	0.7	0.7	0.7	0.8	0.8	0.9	0.9	1.3%
Distribution	2.4	2.4	2.4	2.4	2.4	2.4	2.3	-0.1%
(nominal cents per kilowatthour)								
Generation	5.9	6.0	6.3	6.8	8.1	9.2	10.5	2.4%
Transmission	0.7	0.7	0.8	0.9	1.1	1.2	1.3	3.0%
Distribution	2.3	2.4	2.5	2.8	3.1	3.3	3.4	1.5%
Electric Power Sector Emissions[1]								
Sulfur Dioxide (million tons)	9.40	8.95	7.51	4.17	3.86	3.78	3.74	-3.7%
Nitrogen Oxide (million tons)	3.41	3.29	2.37	2.10	2.10	2.10	2.12	-1.9%
Mercury (tons)	49.04	49.28	45.19	29.08	29.13	29.44	29.57	-2.2%

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes plants that only produce electricity.
[3]Includes electricity generation from fuel cells.
[4]Includes non-biogenic municipal waste. The Energy Information Administration estimates approximately 7 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy*, (Washington, DC, May 2007).
[5]Includes conventional hydroelectric, geothermal, wood, wood waste, biogenic municipal waste, landfill gas, other biomass, solar, and wind power.
[6]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22).
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]Includes refinery gas and still gas.
[9]Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power.
[10]Includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
[11]Includes pumped storage, non-biogenic municipal waste, refinery gas, still gas, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 electric power sector generation; sales to utilities; net imports; electricity sales; and emissions: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008), and supporting databases. 2006 and 2007 prices: EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A. **Projections**: EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A9. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	Reference Case 2006	2007	2010	2015	2020	2025	2030	Annual Growth 2007-2030 (percent)
Electric Power Sector[2]								
Power Only[3]								
Coal	305.2	306.7	316.4	321.5	322.4	323.8	347.9	0.6%
Oil and Natural Gas Steam[4]	119.3	118.4	118.0	101.4	101.4	101.4	100.1	-0.7%
Combined Cycle	144.7	149.2	163.0	163.9	170.3	197.5	205.2	1.4%
Combustion Turbine/Diesel	128.1	130.4	139.2	139.1	152.9	178.7	198.1	1.8%
Nuclear Power[5]	100.2	100.5	101.2	104.1	108.4	108.4	112.6	0.5%
Pumped Storage	21.5	21.5	21.5	21.5	21.5	21.5	21.5	0.0%
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Renewable Sources[6]	95.5	100.8	114.9	116.9	121.7	129.0	138.2	1.4%
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.1	0.3	- -
Total	**914.5**	**927.5**	**974.2**	**968.4**	**998.5**	**1060.4**	**1123.8**	**0.8%**
Combined Heat and Power[8]								
Coal	4.6	4.6	4.6	4.6	4.6	4.6	4.6	0.0%
Oil and Natural Gas Steam[4]	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.0%
Combined Cycle	31.8	31.8	31.8	32.5	32.5	32.5	32.5	0.1%
Combustion Turbine/Diesel	2.9	2.9	2.9	2.9	2.9	2.9	2.9	0.0%
Renewable Sources[6]	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.0%
Total	**40.3**	**40.3**	**40.4**	**41.0**	**41.0**	**41.0**	**41.0**	**0.1%**
Cumulative Planned Additions[9]								
Coal	0.0	0.0	11.3	17.0	17.0	17.0	17.0	- -
Oil and Natural Gas Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Combined Cycle	0.0	0.0	13.8	15.3	15.3	15.3	15.3	- -
Combustion Turbine/Diesel	0.0	0.0	3.2	3.2	3.2	3.2	3.2	- -
Nuclear Power	0.0	0.0	0.0	1.2	1.2	1.2	1.2	- -
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Renewable Sources[6]	0.0	0.0	9.7	9.8	9.9	10.0	10.1	- -
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Total	**0.0**	**0.0**	**38.0**	**46.5**	**46.6**	**46.7**	**46.8**	**- -**
Cumulative Unplanned Additions[9]								
Coal	0.0	0.0	0.0	0.0	1.0	2.4	26.6	- -
Oil and Natural Gas Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Combined Cycle	0.0	0.0	0.0	0.0	6.4	33.6	41.3	- -
Combustion Turbine/Diesel	0.0	0.0	5.9	10.8	24.6	50.4	69.8	- -
Nuclear Power	0.0	0.0	0.0	0.0	3.3	3.3	11.9	- -
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Renewable Sources[6]	0.0	0.0	4.4	6.4	11.0	18.3	27.3	- -
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.1	0.3	- -
Total	**0.0**	**0.0**	**10.3**	**17.1**	**46.3**	**108.1**	**177.1**	**- -**
Cumulative Electric Power Sector Additions	**0.0**	**0.0**	**48.3**	**63.6**	**92.9**	**154.8**	**223.9**	**- -**
Cumulative Retirements[10]								
Coal	0.0	0.0	1.6	2.1	2.3	2.3	2.3	- -
Oil and Natural Gas Steam[4]	0.0	0.0	0.4	17.0	17.0	17.0	18.3	- -
Combined Cycle	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Combustion Turbine/Diesel	0.0	0.0	0.3	5.3	5.3	5.3	5.3	- -
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	4.4	- -
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Renewable Sources[6]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Total	**0.0**	**0.0**	**2.3**	**24.4**	**24.5**	**24.5**	**30.2**	**- -**
Total Electric Power Sector Capacity	**954.8**	**967.8**	**1014.5**	**1009.4**	**1039.5**	**1101.4**	**1164.9**	**0.8%**

Table A9. Electricity Generating Capacity (Continued)
(Gigawatts)

Net Summer Capacity[1]	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
End-Use Generators[11]								
Coal	4.0	4.0	4.0	4.8	5.6	6.7	7.9	3.0%
Petroleum	1.2	1.3	2.6	2.6	2.6	2.6	2.7	3.3%
Natural Gas	14.1	14.0	13.8	15.1	16.4	18.3	21.0	1.8%
Other Gaseous Fuels	1.8	1.5	3.9	3.7	3.7	3.7	3.7	4.2%
Renewable Sources[6]	6.0	6.1	7.5	13.6	18.1	22.4	26.4	6.5%
Other	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.0%
Total	**27.9**	**27.8**	**32.6**	**40.6**	**47.3**	**54.5**	**62.6**	**3.6%**
Cumulative Capacity Additions[9]	**0.0**	**0.0**	**4.8**	**12.8**	**19.5**	**26.7**	**34.8**	**- -**

[1]Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.
[4]Includes oil-, gas-, and dual-fired capacity.
[5]Nuclear capacity includes 3.4 gigawatts of uprates through 2030.
[6]Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
[7]Primarily peak load capacity fueled by natural gas.
[8]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22).
[9]Cumulative additions after December 31, 2007.
[10]Cumulative retirements after December 31, 2007.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A10. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Interregional Electricity Trade								
Gross Domestic Sales								
Firm Power	123.1	124.5	118.7	110.9	81.8	44.9	37.6	-5.1%
Economy	151.1	116.7	207.9	232.3	232.0	204.6	186.5	2.1%
Total	**274.2**	**241.3**	**326.6**	**343.2**	**313.8**	**249.5**	**224.0**	**-0.3%**
Gross Domestic Sales (million 2007 dollars)								
Firm Power	7051.4	7133.1	6799.0	6353.0	4683.5	2574.5	2152.7	-5.1%
Economy	8652.1	7235.0	11340.4	12499.1	12766.6	12674.0	12768.4	2.5%
Total	**15703.6**	**14368.1**	**18139.4**	**18852.1**	**17450.1**	**15248.5**	**14921.1**	**0.2%**
International Electricity Trade								
Imports from Canada and Mexico								
Firm Power	13.7	15.8	16.6	12.0	7.3	1.5	0.4	-14.9%
Economy	28.8	35.6	29.3	27.6	31.4	31.5	46.0	1.1%
Total	**42.4**	**51.4**	**45.9**	**39.6**	**38.7**	**33.1**	**46.4**	**-0.4%**
Exports to Canada and Mexico								
Firm Power	3.2	3.9	0.9	0.9	0.5	0.1	0.0	- -
Economy	21.4	16.2	20.6	21.3	20.4	18.5	18.5	0.6%
Total	**24.6**	**20.1**	**21.5**	**22.1**	**20.9**	**18.6**	**18.5**	**-0.4%**

- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.

Sources: 2006 and 2007 interregional firm electricity trade data: North American Electric Reliability Council (NERC), Electricity Sales and Demand Database 2007. 2006 and 2007 Mexican electricity trade data: Energy Information Administration (EIA), *Electric Power Annual 2007* DOE/EIA-0348(2007) (Washington, DC, December 2008). 2006 Canadian international electricity trade data: National Energy Board, *Annual Report 2006*. 2007 Canadian electricity trade data: National Energy Board, *Annual Report 2007*. **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A11. Liquid Fuels Supply and Disposition
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Crude Oil								
Domestic Crude Production[1]	5.10	5.07	5.62	5.72	6.48	7.21	7.37	1.6%
Alaska	0.74	0.72	0.69	0.51	0.72	0.77	0.57	-1.0%
Lower 48 States	4.36	4.35	4.93	5.21	5.76	6.44	6.80	2.0%
Net Imports	10.09	10.00	8.10	8.10	7.29	6.66	6.95	-1.6%
Gross Imports	10.12	10.03	8.13	8.13	7.33	6.70	6.99	-1.6%
Exports	0.03	0.03	0.03	0.03	0.03	0.04	0.04	1.6%
Other Crude Supply[2]	0.05	0.09	0.00	0.00	0.00	0.00	0.00	- -
Total Crude Supply	**15.24**	**15.16**	**13.72**	**13.83**	**13.77**	**13.87**	**14.32**	**-0.2%**
Other Supply								
Natural Gas Plant Liquids	1.74	1.78	1.91	1.89	1.91	1.93	1.92	0.3%
Net Product Imports	2.31	2.09	1.66	1.64	1.49	1.35	1.40	-1.7%
Gross Refined Product Imports[3]	2.17	1.94	1.64	1.53	1.60	1.51	1.54	-1.0%
Unfinished Oil Imports	0.69	0.72	0.58	0.59	0.58	0.60	0.65	-0.4%
Blending Component Imports	0.68	0.75	0.62	0.75	0.66	0.67	0.69	-0.4%
Exports	1.22	1.32	1.18	1.23	1.35	1.43	1.47	0.5%
Refinery Processing Gain[4]	0.99	1.00	0.97	0.96	0.93	0.89	0.86	-0.6%
Other Inputs	0.41	0.74	1.22	1.66	1.98	2.63	3.08	6.4%
Ethanol	0.36	0.45	0.84	1.07	1.28	1.68	1.91	6.5%
Domestic Production	0.32	0.43	0.84	1.06	1.24	1.43	1.43	5.4%
Net Imports	0.05	0.02	-0.00	0.01	0.04	0.25	0.49	14.5%
Biodiesel	0.02	0.03	0.06	0.10	0.10	0.12	0.13	6.2%
Domestic Production	0.02	0.03	0.06	0.10	0.10	0.12	0.13	6.2%
Net Imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Liquids from Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Liquids from Coal	0.00	0.00	0.00	0.06	0.10	0.18	0.26	- -
Liquids from Biomass	0.00	0.00	0.00	0.01	0.07	0.24	0.33	- -
Other[5]	0.03	0.26	0.32	0.42	0.42	0.42	0.45	2.4%
Total Primary Supply[6]	**20.70**	**20.77**	**19.48**	**19.98**	**20.08**	**20.68**	**21.59**	**0.2%**
Liquid Fuels Consumption								
by Fuel								
Liquefied Petroleum Gases	2.05	2.09	1.99	1.95	1.82	1.78	1.74	-0.8%
E85[7]	0.00	0.00	0.00	0.24	0.58	1.17	1.50	37.1%
Motor Gasoline[8]	9.25	9.29	9.34	8.97	8.60	8.15	8.04	-0.6%
Jet Fuel[9]	1.63	1.62	1.45	1.52	1.65	1.81	1.99	0.9%
Distillate Fuel Oil[10]	4.17	4.20	4.08	4.46	4.62	4.91	5.42	1.1%
Diesel	3.21	3.47	3.47	3.89	4.06	4.38	4.91	1.5%
Residual Fuel Oil	0.69	0.72	0.63	0.69	0.70	0.71	0.72	-0.0%
Other[11]	2.86	2.74	2.19	2.31	2.24	2.22	2.25	-0.8%
by Sector								
Residential and Commercial	1.06	1.11	1.05	1.00	0.99	0.98	0.97	-0.6%
Industrial[12]	5.32	5.26	4.46	4.57	4.34	4.28	4.28	-0.9%
Transportation	14.21	14.25	13.96	14.36	14.65	15.27	16.18	0.6%
Electric Power[13]	0.29	0.30	0.22	0.22	0.23	0.23	0.23	-1.0%
Total	**20.65**	**20.65**	**19.69**	**20.16**	**20.21**	**20.76**	**21.67**	**0.2%**
Discrepancy[14]	**0.04**	**0.12**	**-0.20**	**-0.17**	**-0.13**	**-0.08**	**-0.08**	**- -**

Table A11. Liquid Fuels Supply and Disposition (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Domestic Refinery Distillation Capacity[15]	17.3	17.4	18.0	18.1	18.2	18.3	18.4	0.2%
Capacity Utilization Rate (percent)[16]	90.0	89.0	77.8	77.7	77.1	77.4	79.2	-0.5%
Net Import Share of Product Supplied (percent)	60.2	58.3	50.1	48.8	44.0	39.9	40.9	-1.5%
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2007 dollars)	272.80	280.13	261.60	360.62	344.32	329.89	376.65	1.3%

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes petroleum product stock withdrawals; and domestic sources of other blending components, other hydrocarbons, ethers, and renewable feedstocks for the on-site production of diesel and gasoline.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[7]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[8]Includes ethanol and ethers blended into gasoline.
[9]Includes only kerosene type.
[10]Includes distillate fuel oil and kerosene from petroleum and biomass feedstocks.
[11]Includes aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, liquid hydrogen,and miscellaneous petroleum products.
[12]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[13]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[14]Balancing item. Includes unaccounted for supply, losses, and gains.
[15]End-of-year operable capacity.
[16]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 petroleum product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). Other 2006 data: EIA, *Petroleum Supply Annual 2006,* DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). Other 2007 data: EIA, *Petroleum Supply Annual 2007,* DOE/EIA-0340(2007)/1 (Washington, DC, July 2008). **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A12. Petroleum Product Prices
(2007 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Crude Oil Prices (2007 dollars per barrel)								
Imported Low Sulfur Light Crude Oil[1]	67.82	72.33	80.16	110.49	115.45	121.94	130.43	2.6%
Imported Crude Oil[1]	60.70	63.83	77.56	108.52	112.05	115.33	124.60	3.0%
Delivered Sector Product Prices								
Residential								
Liquefied Petroleum Gases	205.0	213.6	221.1	275.6	281.1	285.9	300.2	1.5%
Distillate Fuel Oil	256.1	272.7	259.2	327.1	334.3	344.6	369.9	1.3%
Commercial								
Distillate Fuel Oil	207.7	221.7	222.8	298.3	304.9	318.0	340.4	1.9%
Residual Fuel Oil	132.9	152.9	164.2	241.3	249.7	255.6	269.1	2.5%
Residual Fuel Oil (2007 dollars per barrel)	55.84	64.22	68.96	101.34	104.88	107.34	113.04	2.5%
Industrial[2]								
Liquefied Petroleum Gases	180.6	199.9	186.7	241.1	246.0	250.9	265.0	1.2%
Distillate Fuel Oil	217.8	232.3	220.2	303.3	309.6	325.0	345.8	1.7%
Residual Fuel Oil	137.9	157.1	230.2	305.9	313.4	320.8	340.2	3.4%
Residual Fuel Oil (2007 dollars per barrel)	57.92	65.98	96.70	128.46	131.64	134.74	142.89	3.4%
Transportation								
Liquefied Petroleum Gases	191.4	213.8	219.5	273.9	278.9	283.2	297.3	1.4%
Ethanol (E85)[3]	242.1	253.0	241.7	242.0	278.0	282.2	285.5	0.5%
Ethanol Wholesale Price	257.0	212.4	192.8	210.8	201.1	189.8	193.8	-0.4%
Motor Gasoline[4]	270.7	282.2	283.9	347.7	359.9	371.1	388.4	1.4%
Jet Fuel[5]	205.8	217.3	216.5	290.0	299.1	310.2	332.4	1.9%
Diesel Fuel (distillate fuel oil)[6]	278.6	287.0	274.9	352.7	356.8	372.2	391.7	1.4%
Residual Fuel Oil	122.8	140.0	181.1	255.6	261.4	271.5	294.1	3.3%
Residual Fuel Oil (2007 dollars per barrel)	51.59	58.80	76.07	107.37	109.80	114.01	123.54	3.3%
Electric Power[7]								
Distillate Fuel Oil	191.0	204.9	209.2	276.0	283.6	295.2	320.5	2.0%
Residual Fuel Oil	125.4	125.4	197.7	272.3	277.7	288.3	309.5	4.0%
Residual Fuel Oil (2007 dollars per barrel)	52.67	52.67	83.03	114.35	116.64	121.08	129.98	4.0%
Refined Petroleum Product Prices[8]								
Liquefied Petroleum Gases	134.4	158.5	179.2	229.4	235.7	240.6	254.5	2.1%
Motor Gasoline[4]	269.0	280.2	283.9	347.7	359.9	371.1	388.4	1.4%
Jet Fuel[5]	205.8	217.3	216.5	290.0	299.1	310.2	332.4	1.9%
Distillate Fuel Oil	264.3	274.5	260.9	341.5	346.8	362.5	383.2	1.5%
Residual Fuel Oil	126.1	138.4	189.6	264.0	269.8	279.5	301.1	3.4%
Residual Fuel Oil (2007 dollars per barrel)	52.97	58.15	79.62	110.88	113.34	117.40	126.47	3.4%
Average	**235.1**	**249.1**	**254.9**	**321.6**	**331.1**	**342.4**	**361.4**	**1.6%**

Table A12. Petroleum Product Prices (Continued)
(Nominal Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Crude Oil Prices (nominal dollars per barrel)								
Imported Low Sulfur Light Crude Oil[1]	66.04	72.33	84.42	127.84	149.14	168.24	189.10	4.3%
Imported Crude Oil[1]	59.10	63.83	81.69	125.57	144.74	159.11	180.66	4.6%
Delivered Sector Product Prices								
Residential								
Liquefied Petroleum Gases	199.6	213.6	232.9	318.9	363.1	394.4	435.2	3.1%
Distillate Fuel Oil	249.4	272.7	273.0	378.5	431.8	475.4	536.3	3.0%
Commercial								
Distillate Fuel Oil	202.2	221.7	234.6	345.1	393.8	438.7	493.5	3.5%
Residual Fuel Oil	129.5	152.9	172.9	279.2	322.6	352.6	390.2	4.2%
Residual Fuel Oil (nominal dollars per barrel)	54.37	64.22	72.63	117.26	135.48	148.09	163.89	4.2%
Industrial[2]								
Liquefied Petroleum Gases	175.9	199.9	196.6	278.9	317.8	346.2	384.2	2.9%
Distillate Fuel Oil	212.1	232.3	231.9	351.0	400.0	448.4	501.4	3.4%
Residual Fuel Oil	134.3	157.1	242.5	353.9	404.9	442.6	493.3	5.1%
Residual Fuel Oil (nominal dollars per barrel)	56.40	65.98	101.84	148.64	170.06	185.89	207.17	5.1%
Transportation								
Liquefied Petroleum Gases	186.3	213.8	231.2	316.9	360.3	390.8	431.0	3.1%
Ethanol (E85)[3]	235.7	253.0	254.5	280.0	359.1	389.4	414.0	2.2%
Ethanol Wholesale Price	250.2	212.4	203.1	243.9	259.8	261.9	280.9	1.2%
Motor Gasoline[4]	263.6	282.2	299.0	402.4	464.9	512.0	563.1	3.0%
Jet Fuel[5]	200.4	217.3	228.0	335.6	386.4	428.0	482.0	3.5%
Diesel Fuel (distillate fuel oil)[6]	271.3	287.0	289.6	408.1	460.9	513.6	567.9	3.0%
Residual Fuel Oil	119.6	140.0	190.8	295.8	337.7	374.5	426.5	5.0%
Residual Fuel Oil (nominal dollars per barrel)	50.24	58.80	80.12	124.24	141.83	157.30	179.11	5.0%
Electric Power[7]								
Distillate Fuel Oil	186.0	204.9	220.4	319.3	366.4	407.3	464.7	3.6%
Residual Fuel Oil	122.1	125.4	208.2	315.0	358.8	397.7	448.7	5.7%
Residual Fuel Oil (nominal dollars per barrel)	51.29	52.67	87.45	132.32	150.68	167.04	188.44	5.7%
Refined Petroleum Product Prices[8]								
Liquefied Petroleum Gases	130.9	158.5	188.7	265.4	304.5	331.9	369.1	3.7%
Motor Gasoline[4]	261.9	280.2	299.0	402.3	464.9	512.0	563.1	3.1%
Jet Fuel[5]	200.4	217.3	228.0	335.6	386.4	428.0	482.0	3.5%
Distillate Fuel Oil	257.3	274.5	274.7	395.2	448.0	500.1	555.7	3.1%
Residual Fuel Oil	122.8	138.4	199.7	305.5	348.6	385.6	436.6	5.1%
Residual Fuel Oil (nominal dollars per barrel)	51.58	58.15	83.86	128.30	146.41	161.97	183.36	5.1%
Average	**228.9**	**249.1**	**268.5**	**372.1**	**427.7**	**472.4**	**524.0**	**3.3%**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]Includes only kerosene type.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 imported low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2006 and 2007 imported crude oil price: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2006 and 2007 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2007*, DOE/EIA-0487(2007) (Washington, DC, August 2008). 2006 and 2007 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2006 and 2007 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2006 and 2007 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2006 and 2007 wholesale ethanol prices derived from Bloomburg U.S. average rack price. **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A13. Natural Gas Supply, Disposition, and Prices
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Production								
Dry Gas Production[1]	18.48	19.30	20.38	20.31	21.48	23.22	23.60	0.9%
Supplemental Natural Gas[2]	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.2%
Net Imports	**3.46**	**3.79**	**2.50**	**2.36**	**1.86**	**1.35**	**0.66**	**-7.3%**
Pipeline[3]	2.94	3.06	2.02	1.11	0.48	0.15	-0.18	- -
Liquefied Natural Gas	0.52	0.73	0.47	1.25	1.38	1.20	0.85	0.7%
Total Supply	**22.00**	**23.15**	**22.94**	**22.73**	**23.40**	**24.64**	**24.33**	**0.2%**
Consumption by Sector								
Residential	4.37	4.72	4.79	4.87	4.96	4.99	4.93	0.2%
Commercial	2.84	3.01	3.06	3.16	3.25	3.36	3.44	0.6%
Industrial[4]	6.49	6.63	6.59	6.80	6.65	6.76	6.85	0.1%
Natural-Gas-to-Liquids Heat and Power[5]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural Gas to Liquids Production[6]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electric Power[7]	6.22	6.87	6.25	6.04	6.54	7.38	6.93	0.0%
Transportation[8]	0.02	0.02	0.03	0.05	0.07	0.08	0.09	6.0%
Pipeline Fuel	0.58	0.62	0.62	0.63	0.67	0.71	0.70	0.5%
Lease and Plant Fuel[9]	1.12	1.17	1.24	1.22	1.29	1.40	1.43	0.9%
Total	**21.65**	**23.05**	**22.57**	**22.77**	**23.43**	**24.67**	**24.36**	**0.2%**
Discrepancy[10]	**0.35**	**0.09**	**0.37**	**-0.03**	**-0.03**	**-0.03**	**-0.03**	**- -**
Natural Gas Prices								
(2007 dollars per million Btu)								
Henry Hub Spot Price	6.91	6.96	6.66	6.90	7.43	8.08	9.25	1.2%
Average Lower 48 Wellhead Price[11]	6.48	6.22	5.88	6.10	6.56	7.13	8.17	1.2%
(2007 dollars per thousand cubic feet)								
Average Lower 48 Wellhead Price[11]	6.66	6.39	6.05	6.27	6.75	7.33	8.40	1.2%
Delivered Prices								
(2007 dollars per thousand cubic feet)								
Residential	14.08	13.05	12.43	12.32	12.85	13.43	14.71	0.5%
Commercial	12.23	11.30	10.84	10.86	11.44	12.07	13.32	0.7%
Industrial[4]	8.18	7.73	7.10	7.21	7.69	8.22	9.33	0.8%
Electric Power[7]	7.25	7.22	6.77	6.90	7.35	7.95	8.94	0.9%
Transportation[12]	16.49	15.89	15.32	15.13	15.31	15.70	16.70	0.2%
Average[13]	**9.77**	**9.26**	**8.80**	**8.88**	**9.37**	**9.88**	**11.05**	**0.8%**

Table A13. Natural Gas Supply, Disposition, and Prices (Continued)
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Natural Gas Prices								
(nominal dollars per million Btu)								
Henry Hub Spot Price	6.73	6.96	7.01	7.99	9.60	11.14	13.42	2.9%
Average Lower 48 Wellhead Price[11]	6.31	6.22	6.19	7.06	8.48	9.84	11.85	2.8%
(nominal dollars per thousand cubic feet)								
Average Lower 48 Wellhead Price[11]	6.49	6.39	6.37	7.26	8.72	10.12	12.18	2.8%
Delivered Prices								
(nominal dollars per thousand cubic feet)								
Residential	13.71	13.05	13.09	14.25	16.60	18.53	21.33	2.2%
Commercial	11.91	11.30	11.42	12.57	14.77	16.66	19.31	2.4%
Industrial[4]	7.96	7.73	7.48	8.34	9.93	11.33	13.52	2.5%
Electric Power[7]	7.06	7.22	7.13	7.99	9.49	10.97	12.96	2.6%
Transportation[12]	16.06	15.89	16.13	17.51	19.78	21.67	24.21	1.8%
Average[13]	**9.51**	**9.26**	**9.26**	**10.28**	**12.10**	**13.63**	**16.02**	**2.4%**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida, as well as gas from Canada and Mexico.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
[6]Includes any natural gas that is converted into liquid fuel.
[7]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[8]Compressed natural gas used as vehicle fuel.
[9]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[10]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2006 and 2007 values include net storage injections.
[11]Represents lower 48 onshore and offshore supplies.
[12]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[13]Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 supply values; and lease, plant, and pipeline fuel consumption: Energy Information Administration (EIA), *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007). 2007 supply values; and lease, plant, and pipeline fuel consumption; and wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). Other 2006 and 2007 consumption based on: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2006 wellhead price: Minerals Management Service and EIA, *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007). 2006 residential and commercial delivered prices: EIA, *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007). 2007 residential and commercial delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2006 and 2007 electric power prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2007 and April 2008, Table 4.13.B. 2006 and 2007 industrial delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007) and the *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2006 transportation sector delivered prices are based on: EIA, *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007) and estimated state taxes, federal taxes, and dispensing costs or charges. 2007 transportation sector delivered prices are model results. **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A14. Oil and Gas Supply

Production and Supply	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Crude Oil								
Lower 48 Average Wellhead Price[1] (2007 dollars per barrel)	**61.80**	**65.70**	**77.30**	**108.44**	**110.99**	**113.79**	**122.82**	**2.8%**
Production (million barrels per day)[2]								
United States Total	5.10	5.07	5.62	5.72	6.48	7.21	7.37	1.6%
Lower 48 Onshore	2.93	2.91	2.92	3.15	3.37	3.79	4.06	1.5%
Lower 48 Offshore	1.43	1.44	2.01	2.07	2.39	2.65	2.74	2.8%
Alaska	0.74	0.72	0.69	0.51	0.72	0.77	0.57	-1.0%
Lower 48 End of Year Reserves[2] (billion barrels)	**18.43**	**18.62**	**19.21**	**20.31**	**22.50**	**24.39**	**25.38**	**1.4%**
Natural Gas								
Lower 48 Average Wellhead Price[1] (2007 dollars per million Btu)								
Henry Hub Spot Price	6.91	6.96	6.66	6.90	7.43	8.08	9.25	1.2%
Average Lower 48 Wellhead Price[1]	6.48	6.22	5.88	6.10	6.56	7.13	8.17	1.2%
(2007 dollars per thousand cubic feet)								
Average Lower 48 Wellhead Price[1]	6.66	6.39	6.05	6.27	6.75	7.33	8.40	1.2%
Dry Production (trillion cubic feet)[3]								
United States Total	18.48	19.30	20.38	20.31	21.48	23.22	23.60	0.9%
Lower 48 Onshore	15.00	15.91	16.75	16.49	16.11	16.23	16.76	0.2%
Associated-Dissolved[4]	1.32	1.39	1.41	1.41	1.37	1.37	1.32	-0.2%
Non-Associated	13.69	14.51	15.34	15.08	14.74	14.86	15.44	0.3%
Conventional	5.06	5.36	4.70	4.13	3.36	2.65	2.18	-3.8%
Unconventional	8.62	9.15	10.64	10.95	11.38	12.20	13.26	1.6%
Gas Shale	1.07	1.17	2.31	2.64	2.97	3.45	4.15	5.7%
Coalbed Methane	1.84	1.84	1.79	1.76	1.78	1.90	2.01	0.4%
Tight Gas	5.71	6.15	6.54	6.55	6.62	6.85	7.10	0.6%
Lower 48 Offshore	3.05	2.97	3.26	3.49	4.23	5.04	4.88	2.2%
Associated-Dissolved[4]	0.63	0.62	0.72	0.89	1.00	1.10	1.16	2.8%
Non-Associated	2.42	2.35	2.55	2.59	3.23	3.94	3.72	2.0%
Alaska	0.42	0.42	0.37	0.33	1.14	1.96	1.96	6.9%
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**200.84**	**225.18**	**230.11**	**218.51**	**213.14**	**211.99**	**211.98**	**-0.3%**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.07**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.2%**
Total Lower 48 Wells Drilled (thousands)	**49.47**	**53.51**	**45.17**	**45.37**	**48.20**	**49.14**	**53.76**	**0.0%**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Marketed production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.

Sources: 2006 and 2007 crude oil lower 48 average wellhead price: Energy Information Administration (EIA), *Petroleum Marketing Annual 2007*, DOE/EIA-0487(2007) (Washington, DC, August 2008). 2006 and 2007 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 2007,* DOE/EIA-0340(2007)/1 (Washington, DC, July 2008). 2006 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(2006) (Washington, DC, December 2007). 2006 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007). 2006 natural gas lower 48 average wellhead price: Minerals Management Service and EIA, *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007). 2007 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). Other 2006 and 2007 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A15. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Production[1]								
Appalachia	392	378	383	343	333	339	353	-0.3%
Interior	151	147	163	192	206	220	252	2.4%
West	619	621	632	671	671	690	735	0.7%
East of the Mississippi	491	478	500	476	478	491	529	0.4%
West of the Mississippi	672	668	677	730	732	757	812	0.8%
Total	**1163**	**1147**	**1177**	**1206**	**1210**	**1248**	**1341**	**0.7%**
Waste Coal Supplied[2]	**14**	**14**	**11**	**13**	**12**	**12**	**13**	**-0.4%**
Net Imports								
Imports[3]	34	34	34	38	48	45	53	1.9%
Exports	50	59	82	65	53	53	44	-1.3%
Total	**-15**	**-25**	**-48**	**-28**	**-5**	**-8**	**10**	**- -**
Total Supply[4]	**1162**	**1136**	**1140**	**1192**	**1217**	**1252**	**1363**	**0.8%**
Consumption by Sector								
Residential and Commercial	3	4	3	3	3	3	3	-0.4%
Coke Plants	23	23	21	20	19	18	18	-1.0%
Other Industrial[5]	59	57	60	56	56	56	57	-0.0%
Coal-to-Liquids Heat and Power	0	0	0	9	16	26	38	- -
Coal to Liquids Production	0	0	0	8	14	22	32	- -
Electric Power[6]	1027	1046	1056	1096	1110	1126	1215	0.7%
Total	**1112**	**1129**	**1140**	**1192**	**1218**	**1252**	**1363**	**0.8%**
Discrepancy and Stock Change[7]	**50**	**7**	**0**	**-0**	**-0**	**-0**	**-0**	**- -**
Average Minemouth Price[8]								
(2007 dollars per short ton)	25.29	25.82	29.45	28.71	27.90	28.45	29.10	0.5%
(2007 dollars per million Btu)	1.25	1.27	1.44	1.42	1.39	1.42	1.46	0.6%
Delivered Prices (2007 dollars per short ton)[9]								
Coke Plants	95.37	94.97	114.53	115.38	115.37	119.22	115.57	0.9%
Other Industrial[5]	53.06	54.42	54.81	55.54	54.65	55.51	57.22	0.2%
Coal to Liquids	- -	- -	- -	17.14	17.89	19.89	20.96	- -
Electric Power								
(2007 dollars per short ton)	34.86	35.45	37.71	38.47	38.04	38.83	40.61	0.6%
(2007 dollars per million Btu)	1.74	1.78	1.89	1.94	1.92	1.96	2.04	0.6%
Average	**37.11**	**37.60**	**40.03**	**40.30**	**39.50**	**40.03**	**41.30**	**0.4%**
Exports[10]	72.84	70.25	83.77	88.70	89.48	89.86	80.02	0.6%

Table A15. Coal Supply, Disposition, and Prices (Continued)
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Average Minemouth Price[8]								
(nominal dollars per short ton)	24.63	25.82	31.02	33.22	36.04	39.26	42.20	2.2%
(nominal dollars per million Btu)	1.21	1.27	1.52	1.65	1.80	1.96	2.11	2.2%
Delivered Prices (nominal dollars per short ton)[9]								
Coke Plants	92.87	94.97	120.62	133.51	149.04	164.48	167.56	2.5%
Other Industrial[5]	51.67	54.42	57.73	64.27	70.59	76.59	82.96	1.9%
Coal to Liquids	0.00	0.00	0.00	19.83	23.11	27.45	30.39	- -
Electric Power								
(nominal dollars per short ton)	33.95	35.45	39.72	44.51	49.14	53.57	58.88	2.2%
(nominal dollars per million Btu)	1.69	1.78	1.99	2.25	2.48	2.70	2.95	2.2%
Average	**36.14**	**37.60**	**42.16**	**46.63**	**51.03**	**55.22**	**59.88**	**2.0%**
Exports[10]	70.93	70.25	88.23	102.64	115.59	123.97	116.02	2.2%

[1]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[2]Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[4]Production plus waste coal supplied plus net imports.
[5]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal use in the coal-to-liquids process.
[6]Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Balancing item: the sum of production, net imports, and waste coal supplied minus total consumption.
[8]Includes reported prices for both open market and captive mines.
[9]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
[10]F.a.s. price at U.S. port of exit.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 data based on: Energy Information Administration (EIA), *Annual Coal Report 2007*, DOE/EIA-0584(2007) (Washington, DC, September 2008); EIA, *Quarterly Coal Report, October-December 2007*, DOE/EIA-0121(2007/4Q) (Washington, DC, March 2008); and EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A. **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A16. Renewable Energy Generating Capacity and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Electric Power Sector[1]								
Net Summer Capacity								
Conventional Hydropower	76.72	76.72	76.73	76.89	77.02	77.31	77.58	0.0%
Geothermal[2]	2.29	2.36	2.53	2.60	2.66	2.73	3.00	1.1%
Municipal Waste[3]	3.39	3.43	4.04	4.08	4.12	4.14	4.15	0.8%
Wood and Other Biomass[4,5]	2.01	2.18	2.20	2.20	4.22	5.20	8.86	6.3%
Solar Thermal	0.40	0.53	0.54	0.79	0.81	0.84	0.86	2.1%
Solar Photovoltaic[6]	0.03	0.04	0.06	0.13	0.21	0.29	0.38	10.4%
Wind	11.29	16.19	29.46	30.68	33.07	39.00	43.80	4.4%
Offshore Wind	0.00	0.00	0.00	0.20	0.20	0.20	0.20	- -
Total	**96.13**	**101.46**	**115.57**	**117.58**	**122.32**	**129.71**	**138.83**	**1.4%**
Generation (billion kilowatthours)								
Conventional Hydropower	286.11	245.86	268.05	295.33	296.29	297.94	298.97	0.9%
Geothermal[2]	14.57	14.84	17.78	18.62	19.11	19.63	21.80	1.7%
Biogenic Municipal Waste[7]	13.71	14.42	19.30	19.61	19.95	20.11	20.17	1.5%
Wood and Other Biomass[5]	10.33	10.38	28.07	56.22	117.82	133.50	140.44	12.0%
Dedicated Plants	8.42	8.41	12.85	13.11	28.74	36.19	62.27	9.1%
Cofiring	1.91	1.97	15.22	43.11	89.08	97.30	78.17	17.4%
Solar Thermal	0.49	0.60	0.99	1.81	1.88	1.95	2.02	5.5%
Solar Photovoltaic[6]	0.01	0.01	0.14	0.30	0.49	0.72	0.94	21.3%
Wind	26.59	32.14	80.50	84.48	92.45	112.13	129.38	6.2%
Offshore Wind	0.00	0.00	0.00	0.75	0.75	0.75	0.75	- -
Total	**351.82**	**318.25**	**414.82**	**477.12**	**548.75**	**586.72**	**614.47**	**2.9%**
End-Use Generators[8]								
Net Summer Capacity								
Conventional Hydropower[9]	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Municipal Waste[10]	0.33	0.34	0.34	0.34	0.34	0.34	0.34	0.0%
Biomass	4.64	4.64	4.65	5.44	7.28	11.03	13.23	4.7%
Solar Photovoltaic[6]	0.28	0.43	1.73	7.05	9.72	10.14	11.78	15.5%
Wind	0.04	0.04	0.04	0.04	0.09	0.17	0.31	9.2%
Total	**5.99**	**6.15**	**7.45**	**13.57**	**18.12**	**22.37**	**26.35**	**6.5%**
Generation (billion kilowatthours)								
Conventional Hydropower[9]	2.99	2.45	2.45	2.45	2.45	2.45	2.45	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Municipal Waste[10]	1.98	2.01	2.75	2.75	2.75	2.75	2.75	1.4%
Biomass	28.32	28.13	28.20	33.41	47.17	75.54	90.81	5.2%
Solar Photovoltaic[6]	0.44	0.68	2.78	11.55	16.02	16.69	19.49	15.7%
Wind	0.06	0.06	0.06	0.06	0.12	0.25	0.45	9.5%
Total	**33.78**	**33.33**	**36.24**	**50.23**	**68.51**	**97.69**	**115.95**	**5.6%**

Table A16. Renewable Energy Generating Capacity and Generation (Continued)
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Total, All Sectors								
Net Summer Capacity								
Conventional Hydropower	77.42	77.42	77.43	77.59	77.72	78.01	78.28	0.0%
Geothermal	2.29	2.36	2.53	2.60	2.66	2.73	3.00	1.1%
Municipal Waste	3.72	3.77	4.38	4.42	4.46	4.48	4.49	0.8%
Wood and Other Biomass[4,5]	6.65	6.82	6.85	7.64	11.50	16.23	22.08	5.2%
Solar[6]	0.71	1.00	2.33	7.97	10.74	11.27	13.02	11.8%
Wind	11.33	16.23	29.50	30.92	33.35	39.37	44.31	4.5%
Total	**102.12**	**107.60**	**123.02**	**131.15**	**140.44**	**152.08**	**165.18**	**1.9%**
Generation (billion kilowatthours)								
Conventional Hydropower	289.11	248.31	270.50	297.78	298.75	300.39	301.42	0.8%
Geothermal	14.57	14.84	17.78	18.62	19.11	19.63	21.80	1.7%
Municipal Waste	15.69	16.43	22.05	22.37	22.70	22.86	22.93	1.5%
Wood and Other Biomass[5]	38.65	38.51	56.26	89.63	164.99	209.04	231.25	8.1%
Solar[6]	0.95	1.29	3.91	13.66	18.39	19.36	22.45	13.2%
Wind	26.64	32.20	80.55	85.29	93.32	113.12	130.57	6.3%
Total	**385.61**	**351.58**	**451.06**	**527.36**	**617.26**	**684.41**	**730.42**	**3.2%**

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[4]Facilities co-firing biomass and coal are classified as coal.
[5]Includes projections for energy crops after 2012.
[6]Does not include off-grid photovoltaics (PV). Based on annual PV shipments from 1989 through 2006, EIA estimates that as much as 210 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2006, plus an additional 526 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008), Table 10.8 (annual PV shipments, 1989-2006). The approach used to develop the estimate, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It will overestimate the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier will be retired from service or abandoned.
[7]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. Only biogenic municipal waste is included. The Energy Information Administration estimates that in 2007 approximately 6 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy* (Washington, DC, May 2007).
[8]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[9]Represents own-use industrial hydroelectric power.
[10]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 capacity: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). 2006 and 2007 generation: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A17. Renewable Energy, Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Marketed Renewable Energy[2]								
Residential (wood)	**0.39**	**0.43**	**0.43**	**0.46**	**0.48**	**0.49**	**0.50**	**0.7%**
Commercial (biomass)	**0.12**	**0.12**	**0.12**	**0.12**	**0.12**	**0.12**	**0.12**	**0.0%**
Industrial[3]	**2.00**	**2.04**	**2.23**	**2.51**	**2.87**	**3.41**	**3.62**	**2.5%**
Conventional Hydroelectric	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.0%
Municipal Waste[4]	0.15	0.16	0.12	0.12	0.12	0.12	0.12	-1.2%
Biomass	1.52	1.46	1.34	1.41	1.49	1.64	1.81	0.9%
Biofuels Heat and Coproducts	0.30	0.40	0.75	0.95	1.23	1.62	1.66	6.4%
Transportation	**0.50**	**0.64**	**1.23**	**1.68**	**2.06**	**2.93**	**3.43**	**7.6%**
Ethanol used in E85[5]	0.00	0.00	0.00	0.23	0.56	1.12	1.44	37.1%
Ethanol used in Gasoline Blending	0.47	0.58	1.08	1.15	1.10	1.04	1.04	2.6%
Biodiesel used in Distillate Blending	0.03	0.06	0.12	0.20	0.20	0.24	0.25	6.2%
Liquids from Biomass	0.00	0.00	0.00	0.02	0.15	0.47	0.65	- -
Green Liquids	0.00	0.00	0.02	0.08	0.06	0.06	0.06	- -
Electric Power[6]	**3.76**	**3.45**	**4.42**	**5.07**	**5.79**	**6.17**	**6.43**	**2.7%**
Conventional Hydroelectric	2.84	2.44	2.65	2.92	2.92	2.94	2.95	0.8%
Geothermal	0.31	0.31	0.38	0.41	0.43	0.44	0.51	2.1%
Biogenic Municipal Waste[7]	0.15	0.17	0.23	0.24	0.24	0.24	0.24	1.7%
Biomass	0.19	0.21	0.35	0.64	1.25	1.40	1.41	8.6%
Dedicated Plants	0.15	0.16	0.15	0.13	0.28	0.35	0.61	5.9%
Cofiring	0.04	0.05	0.21	0.51	0.98	1.05	0.80	12.9%
Solar Thermal	0.00	0.01	0.01	0.02	0.02	0.02	0.02	5.5%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.01	0.01	21.3%
Wind	0.26	0.32	0.80	0.84	0.92	1.12	1.29	6.3%
Total Marketed Renewable Energy	**6.77**	**6.69**	**8.43**	**9.84**	**11.32**	**13.12**	**14.10**	**3.3%**
Sources of Ethanol								
From Corn	0.41	0.55	1.08	1.34	1.42	1.42	1.41	4.2%
From Cellulose	0.00	0.00	0.00	0.03	0.18	0.42	0.43	- -
Imports	0.06	0.03	-0.00	0.01	0.06	0.32	0.63	14.5%
Total	**0.47**	**0.58**	**1.08**	**1.39**	**1.66**	**2.16**	**2.47**	**6.5%**

Table A17. Renewable Energy, Consumption by Sector and Source[1] (Continued)
(Quadrillion Btu per Year)

Sector and Source	Reference Case 2006	2007	2010	2015	2020	2025	2030	Annual Growth 2007-2030 (percent)
Nonmarketed Renewable Energy[8] Selected Consumption								
Residential	**0.01**	**0.01**	**0.01**	**0.05**	**0.07**	**0.07**	**0.08**	**11.5%**
Solar Hot Water Heating	0.00	0.00	0.00	0.00	0.00	0.01	0.01	2.6%
Geothermal Heat Pumps	0.00	0.00	0.00	0.01	0.01	0.02	0.02	9.1%
Solar Photovoltaic	0.00	0.00	0.01	0.03	0.05	0.05	0.05	25.2%
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0%
Commercial	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**2.0%**
Solar Thermal	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.5%
Solar Photovoltaic	0.00	0.00	0.00	0.01	0.01	0.01	0.01	8.4%
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.3%

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,022 Btu per kilowatthour.
[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table A2.
[3]Includes all electricity production by industrial and other combined heat and power for the grid and for own use.
[4]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[5]Excludes motor gasoline component of E85.
[6]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[7]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. Only biogenic municipal waste is included. The Energy Information Administration estimates that in 2007 approximately 0.3 quadrillion Btus were consumed from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy* (Washington, DC, May 2007).
[8]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 ethanol: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2006 and 2007 electric power sector: EIA, Form EIA-860, "Annual Electric Generator Report" (preliminary). Other 2006 and 2007 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A18. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Residential								
Petroleum	89	88	89	82	80	77	75	-0.7%
Natural Gas	237	257	261	266	270	272	269	0.2%
Coal	1	1	1	1	1	1	1	1.1%
Electricity[1]	871	904	886	876	899	930	987	0.4%
Total	**1198**	**1250**	**1237**	**1224**	**1250**	**1280**	**1332**	**0.3%**
Commercial								
Petroleum	45	45	41	42	42	42	42	-0.3%
Natural Gas	154	163	167	172	177	183	188	0.6%
Coal	6	7	6	6	6	6	6	-0.4%
Electricity[1]	837	872	878	926	979	1026	1096	1.0%
Total	**1043**	**1088**	**1092**	**1147**	**1205**	**1257**	**1332**	**0.9%**
Industrial[2]								
Petroleum	420	406	377	378	369	367	375	-0.4%
Natural Gas[3]	395	405	414	424	421	433	440	0.4%
Coal	186	175	174	178	183	198	215	0.9%
Electricity[1]	652	653	617	631	612	610	638	-0.1%
Total	**1653**	**1640**	**1582**	**1610**	**1585**	**1607**	**1667**	**0.1%**
Transportation								
Petroleum[4]	1975	1974	1851	1880	1896	1931	2032	0.1%
Natural Gas[5]	33	35	36	37	40	43	43	0.8%
Electricity[1]	4	4	4	5	6	7	9	3.3%
Total	**2013**	**2014**	**1891**	**1922**	**1942**	**1982**	**2084**	**0.1%**
Electric Power[6]								
Petroleum	66	66	38	39	40	40	41	-2.0%
Natural Gas	339	376	341	329	357	403	378	0.0%
Coal	1947	1980	1995	2058	2089	2118	2299	0.7%
Other[7]	12	12	12	12	12	12	12	0.1%
Total	**2364**	**2433**	**2385**	**2437**	**2497**	**2572**	**2729**	**0.5%**
Total by Fuel								
Petroleum[3]	2596	2580	2396	2421	2427	2458	2564	-0.0%
Natural Gas	1159	1237	1218	1228	1265	1333	1318	0.3%
Coal	2140	2162	2176	2242	2278	2322	2521	0.7%
Other[7]	12	12	12	12	12	12	12	0.1%
Total	**5907**	**5991**	**5801**	**5904**	**5982**	**6125**	**6414**	**0.3%**
Carbon Dioxide Emissions (tons per person)	**19.7**	**19.8**	**18.6**	**18.1**	**17.5**	**17.1**	**17.1**	**-0.6%**

[1]Emissions from the electric power sector are distributed to the end-use sectors.
[2]Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes lease and plant fuel.
[4]This includes carbon dioxide from international bunker fuels, both civilian and military, which are excluded from the accounting of carbon dioxide emissions under the United Nations convention. From 1990 through 2007, international bunker fuels accounted for 84 to 131 million metric tons annually.
[5]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[6]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2007,* DOE/EIA-0573(2007) (Washington, DC, December 2008). **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A19. Energy-Related Carbon Dioxide Emissions by End Use
(Million Metric Tons)

Sector and Source	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Residential								
Space Heating	262.44	292.79	291.82	290.68	291.30	289.27	286.17	-0.1%
Space Cooling	157.96	168.73	158.68	162.58	169.72	177.92	190.05	0.5%
Water Heating	165.56	165.97	161.74	161.39	166.79	168.00	165.41	-0.0%
Refrigeration	73.73	73.53	68.88	67.07	67.93	69.20	73.42	-0.0%
Cooking	33.18	33.74	34.00	35.62	37.37	38.57	40.30	0.8%
Clothes Dryers	54.20	54.72	53.38	53.66	53.99	54.92	58.11	0.3%
Freezers	15.59	15.54	14.64	14.43	14.66	14.91	15.66	0.0%
Lighting	140.12	139.35	132.07	106.42	97.54	91.23	90.61	-1.9%
Clothes Washers[1]	6.70	6.65	5.99	5.39	4.74	4.65	4.93	-1.3%
Dishwashers[1]	18.04	18.13	17.32	17.27	17.81	18.61	20.07	0.4%
Color Televisions and Set-Top Boxes	64.02	68.64	74.30	74.34	77.16	85.02	97.19	1.5%
Personal Computers and Related Equipment	27.08	29.19	33.47	33.48	34.62	36.41	39.39	1.3%
Furnace Fans and Boiler Circulation Pumps	21.51	24.35	24.21	25.57	26.76	27.36	28.42	0.7%
Other Uses	157.49	165.08	166.42	176.29	189.62	203.60	222.05	1.3%
Discrepancy[2]	0.57	-6.59	0.00	-0.00	0.00	-0.00	0.00	- -
Total Residential	**1198.19**	**1249.82**	**1236.92**	**1224.19**	**1250.00**	**1279.66**	**1331.78**	**0.3%**
Commercial								
Space Heating[3]	112.77	121.65	122.71	124.04	125.18	124.75	123.26	0.1%
Space Cooling[3]	102.77	107.73	102.62	104.73	106.83	109.55	115.01	0.3%
Water Heating[3]	43.27	43.32	42.19	44.11	45.75	47.13	47.99	0.4%
Ventilation	90.03	93.93	97.80	106.84	113.27	117.77	123.43	1.2%
Cooking	13.01	13.26	13.67	14.19	14.70	15.23	15.65	0.7%
Lighting	203.06	204.00	195.55	198.02	202.04	204.53	210.90	0.1%
Refrigeration	74.86	76.78	73.02	68.19	66.80	66.88	69.59	-0.4%
Office Equipment (PC)	40.50	46.08	46.77	48.70	51.55	55.00	58.63	1.1%
Office Equipment (non-PC)	36.39	40.08	47.47	57.87	66.68	70.90	75.05	2.8%
Other Uses[4]	326.54	340.75	350.49	380.06	411.93	445.25	492.05	1.6%
Total Commercial	**1043.20**	**1087.58**	**1092.29**	**1146.73**	**1204.72**	**1256.98**	**1331.56**	**0.9%**
Industrial								
Manufacturing								
Refining	250.67	251.30	258.31	279.74	291.74	304.37	327.84	1.2%
Food Products	95.58	98.58	103.37	103.68	107.57	112.37	119.68	0.8%
Paper Products	97.37	93.56	87.16	86.97	85.70	85.71	88.86	-0.2%
Bulk Chemicals	313.24	313.68	279.94	272.61	247.77	236.18	221.91	-1.5%
Glass	17.09	17.18	16.88	20.35	21.25	21.53	21.37	1.0%
Cement Manufacturing	42.36	41.73	32.97	39.81	40.16	40.76	40.58	-0.1%
Iron and Steel	141.17	137.15	117.98	122.20	113.43	113.69	116.17	-0.7%
Aluminum	46.43	44.83	42.50	40.07	36.66	34.18	32.23	-1.4%
Fabricated Metal Products	42.57	42.78	36.15	40.05	36.82	36.73	36.51	-0.7%
Machinery	21.55	21.37	18.40	21.20	20.66	21.09	21.97	0.1%
Computers and Electronics	28.11	29.59	24.66	28.68	32.37	38.09	53.58	2.6%
Transportation Equipment	43.21	42.05	39.29	41.73	40.09	41.11	41.69	-0.0%
Electrical Equipment	16.99	17.30	13.91	16.23	16.85	18.65	22.37	1.1%
Wood Products	18.37	17.78	17.80	22.20	20.10	19.42	19.59	0.4%
Plastics	40.88	40.78	37.60	38.42	38.84	39.57	43.38	0.3%
Balance of Manufacturing	174.80	170.54	150.34	153.92	154.38	154.34	160.37	-0.3%
Total Manufacturing	1390.40	1380.18	1277.28	1327.87	1304.41	1317.79	1368.09	-0.0%
Nonmanufacturing								
Agriculture	82.05	96.37	86.33	87.23	85.70	86.14	88.95	-0.3%
Mining	81.75	76.75	59.38	76.15	72.43	72.49	76.07	-0.0%
Construction	83.77	80.59	77.18	77.98	76.44	78.28	79.62	-0.1%
Total Nonmanufacturing	247.57	253.71	222.89	241.36	234.56	236.91	244.63	-0.2%
Discrepancy[2]	14.59	5.93	81.53	40.91	46.14	52.42	54.56	10.1%
Total Industrial	**1652.56**	**1639.83**	**1581.70**	**1610.14**	**1585.11**	**1607.12**	**1667.28**	**0.1%**

Table A19. Energy-Related Carbon Dioxide Emissions by End Use (Continued)
(Million Metric Tons)

Sector and Source	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Transportation								
Light-Duty Vehicles	1146.29	1137.83	1076.13	1030.99	1007.98	988.58	1002.45	-0.5%
Commercial Light Trucks[5]	43.12	43.08	37.81	40.32	39.85	40.72	44.04	0.1%
Bus Transportation	19.95	19.57	19.11	18.99	19.08	19.42	20.06	0.1%
Freight Trucks	368.22	371.85	343.12	392.59	409.93	436.61	488.21	1.2%
Rail, Passenger	5.69	5.82	5.84	6.29	6.60	6.88	7.30	1.0%
Rail, Freight	42.89	43.01	40.74	44.59	46.39	48.30	52.19	0.8%
Shipping, Domestic	25.02	25.11	23.52	25.88	27.51	29.30	30.69	0.9%
Shipping, International	66.06	69.31	62.74	69.81	70.25	70.69	71.23	0.1%
Recreational Boats	17.26	17.48	16.86	17.28	17.63	18.07	18.55	0.3%
Air	192.25	192.03	173.66	185.56	203.42	225.45	250.83	1.2%
Military Use	49.63	50.27	52.93	51.51	52.83	54.13	55.40	0.4%
Lubricants	5.45	5.19	5.17	5.32	5.41	5.52	5.67	0.4%
Pipeline Fuel	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.5%
Discrepancy[2]	30.97	33.02	32.85	33.30	35.50	37.89	37.16	0.5%
Total Transportation	**2012.83**	**2013.59**	**1890.52**	**1922.48**	**1942.43**	**1981.59**	**2083.81**	**0.1%**

[1]Does not include water heating portion of load.
[2]Represents differences between total emissions by end-use and total emissions by fuel as reported in Table A18. Emissions by fuel may reflect benchmarking and other modeling adjustments to energy use and the associated emissions that are not assigned to specific end uses.
[3]Includes emissions related to fuel consumption for district services.
[4]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, emergency generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus emissions from residual fuel oil, liquefied petroleum gases, coal, motor gasoline, and kerosene.
[5]Commercial trucks 8,500 to 10,000 pounds.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2007,* DOE/EIA-0573(2007) (Washington, DC, December 2008). **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A20. Macroeconomic Indicators
(Billion 2000 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Real Gross Domestic Product	**11295**	**11524**	**11779**	**13745**	**15524**	**17591**	**20114**	**2.5%**
Components of Real Gross Domestic Product								
Real Consumption	8029	8253	8435	9626	10876	12144	13439	2.1%
Real Investment	1912	1810	1581	2265	2565	3067	3756	3.2%
Real Government Spending	1971	2012	2065	2094	2194	2296	2427	0.8%
Real Exports	1315	1426	1585	2291	3061	4122	5820	6.3%
Real Imports	1931	1972	1899	2446	3007	3722	4717	3.9%
Energy Intensity								
(thousand Btu per 2000 dollar of GDP)								
Delivered Energy	6.45	6.42	6.09	5.39	4.86	4.44	4.04	-2.0%
Total Energy	8.86	8.84	8.48	7.48	6.79	6.20	5.65	-1.9%
Price Indices								
GDP Chain-type Price Index (2000=1.000)	1.167	1.198	1.262	1.386	1.548	1.653	1.737	1.6%
Consumer Price Index (1982-4=1.00)								
All-urban	2.02	2.07	2.20	2.49	2.83	3.08	3.31	2.1%
Energy Commodities and Services	1.97	2.08	2.18	2.75	3.16	3.48	3.87	2.7%
Wholesale Price Index (1982=1.00)								
All Commodities	1.65	1.73	1.80	2.01	2.19	2.27	2.36	1.4%
Fuel and Power	1.67	1.77	1.91	2.37	2.74	3.04	3.45	2.9%
Metals and Metal Products	1.82	1.93	1.82	2.08	2.21	2.17	2.22	0.6%
Interest Rates (percent, nominal)								
Federal Funds Rate	4.96	5.02	1.30	5.43	5.20	5.17	4.04	- -
10-Year Treasury Note	4.79	4.63	3.67	5.74	5.86	5.64	4.67	- -
AA Utility Bond Rate	5.84	5.94	6.39	7.71	7.49	7.12	5.79	- -
Value of Shipments (billion 2000 dollars)								
Total Industrial	5763	5750	5240	6276	6753	7402	8451	1.7%
Nonmanufacturing	1503	1490	1277	1581	1603	1671	1780	0.8%
Manufacturing	4260	4261	3963	4694	5150	5732	6671	2.0%
Energy-Intensive	1218	1239	1238	1321	1374	1441	1525	0.9%
Non-energy Intensive	3042	3022	2725	3373	3776	4290	5145	2.3%
Population and Employment (millions)								
Population, with Armed Forces Overseas	299.6	302.4	311.4	326.7	342.6	358.9	375.1	0.9%
Population, aged 16 and over	234.5	237.2	245.2	257.4	270.4	283.9	297.6	1.0%
Population, over age 65	37.4	38.0	40.4	47.0	55.0	64.2	72.3	2.8%
Employment, Nonfarm	135.7	137.2	135.6	147.2	152.6	159.2	168.3	0.9%
Employment, Manufacturing	14.2	13.9	12.2	12.6	12.3	12.1	11.7	-0.7%
Key Labor Indicators								
Labor Force (millions)	151.4	153.1	155.9	163.2	168.4	174.0	181.5	0.7%
Nonfarm Labor Productivity (1992=1.00)	1.35	1.37	1.45	1.57	1.74	1.93	2.14	2.0%
Unemployment Rate (percent)	4.61	4.64	8.26	5.68	5.53	5.41	4.78	- -
Key Indicators for Energy Demand								
Real Disposable Personal Income	8407	8644	9017	10468	12035	13715	15450	2.6%
Housing Starts (millions)	1.93	1.44	1.18	2.00	1.77	1.74	1.74	0.8%
Commercial Floorspace (billion square feet)	75.8	77.3	81.2	86.1	92.3	97.5	103.3	1.3%
Unit Sales of Light-Duty Vehicles (millions)	16.50	16.09	14.18	17.07	17.41	18.86	20.99	1.2%

GDP = Gross domestic product.
Btu = British thermal unit.
- - = Not applicable.
Sources: 2006 and 2007: IHS Global Insight Industry and Employment models, November 2008. **Projections:** Energy Information Administration, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A21. International Liquids Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Crude Oil Prices (2007 dollars per barrel)[1]								
Imported Low Sulfur Light Crude Oil	67.82	72.33	80.16	110.49	115.45	121.94	130.43	2.6%
Imported Crude Oil	60.70	63.83	77.56	108.52	112.05	115.33	124.60	3.0%
Crude Oil Prices (nominal dollars per barrel)[1]								
Imported Low Sulfur Light Crude Oil	66.04	72.33	84.42	127.84	149.14	168.24	189.10	4.3%
Imported Crude Oil	59.10	63.83	81.69	125.57	144.74	159.11	180.66	4.6%
Conventional Production (Conventional)[2]								
OPEC[3]								
Middle East	23.50	22.97	22.77	23.62	25.22	26.59	28.34	0.9%
North Africa	3.93	4.02	4.25	4.54	4.61	4.81	5.19	1.1%
West Africa	3.88	4.12	4.81	5.19	5.23	5.48	5.92	1.6%
South America	2.68	2.58	2.26	2.14	2.42	2.66	2.73	0.2%
Total OPEC	**33.99**	**33.68**	**34.09**	**35.49**	**37.48**	**39.53**	**42.18**	**1.0%**
Non-OPEC								
OECD								
United States (50 states)	7.86	8.11	8.81	8.96	9.71	10.38	10.44	1.1%
Canada	2.06	2.05	1.90	1.50	1.25	1.11	1.02	-3.0%
Mexico	3.71	3.50	2.87	2.53	2.24	2.29	2.45	-1.5%
OECD Europe[4]	5.48	5.23	4.27	3.61	3.18	3.01	2.94	-2.5%
Japan	0.13	0.13	0.14	0.15	0.16	0.17	0.18	1.3%
Australia and New Zealand	0.58	0.64	0.82	0.79	0.78	0.78	0.77	0.8%
Total OECD	**19.82**	**19.66**	**18.80**	**17.54**	**17.32**	**17.73**	**17.81**	**-0.4%**
Non-OECD								
Russia	9.68	9.88	9.50	9.73	10.24	10.28	10.50	0.3%
Other Europe and Eurasia[5]	2.63	2.88	3.58	4.15	4.50	4.60	4.86	2.3%
China	3.84	3.90	3.75	3.53	3.52	3.32	3.19	-0.9%
Other Asia[6]	3.88	3.75	3.88	3.73	3.85	3.85	3.68	-0.1%
Middle East	1.62	1.52	1.42	1.40	1.40	1.37	1.36	-0.5%
Africa	2.41	2.41	2.65	2.60	2.72	2.85	2.98	0.9%
Brazil	1.86	1.88	2.48	2.90	3.45	3.82	4.19	3.5%
Other Central and South America	1.83	1.79	1.70	1.51	1.56	1.76	2.05	0.6%
Total Non-OECD	**27.75**	**28.01**	**28.96**	**29.56**	**31.25**	**31.83**	**32.81**	**0.7%**
Total Conventional Production	**81.56**	**81.35**	**81.85**	**82.58**	**86.04**	**89.10**	**92.80**	**0.6%**
Unconventional Production[7]								
United States (50 states)	0.34	0.46	0.91	1.27	1.55	2.04	2.31	7.3%
Other North America	1.23	1.38	1.92	2.83	3.34	3.86	4.31	5.1%
OECD Europe[4]	0.09	0.11	0.13	0.15	0.19	0.23	0.27	4.1%
Middle East	0.09	0.09	0.01	0.12	0.17	0.21	0.22	3.7%
Africa.	0.17	0.23	0.27	0.42	0.50	0.61	0.72	5.2%
Central and South America	0.91	1.02	1.15	1.51	2.04	2.61	3.16	5.0%
Other	0.24	0.30	0.47	0.60	0.78	1.23	1.63	7.7%
Total Unconventional Production	**3.06**	**3.58**	**4.85**	**6.89**	**8.56**	**10.78**	**12.61**	**5.6%**
Total Production	**84.62**	**84.93**	**86.71**	**89.47**	**94.60**	**99.88**	**105.41**	**0.9%**

Table A21. International Liquids Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Consumption[8]								
OECD								
United States (50 states)	20.65	20.65	19.69	20.16	20.21	20.76	21.67	0.2%
United States Territories	0.38	0.39	0.44	0.49	0.53	0.57	0.62	2.0%
Canada	2.31	2.41	2.28	2.24	2.29	2.34	2.39	-0.0%
Mexico	2.06	2.10	2.06	2.13	2.28	2.46	2.67	1.0%
OECD Europe[3]	15.75	15.36	14.74	14.24	14.24	14.28	14.27	-0.3%
Japan	5.22	5.02	4.68	4.37	4.27	4.16	4.02	-1.0%
South Korea	2.29	2.34	2.31	2.46	2.58	2.71	2.81	0.8%
Australia and New Zealand	1.06	1.08	1.04	1.05	1.09	1.14	1.20	0.5%
Total OECD	**49.73**	**49.35**	**47.24**	**47.14**	**47.50**	**48.43**	**49.64**	**0.0%**
Non-OECD								
Russia	2.83	2.88	2.97	3.02	3.18	3.29	3.35	0.7%
Other Europe and Eurasia[5]	2.18	2.24	2.34	2.46	2.64	2.81	2.96	1.2%
China	7.22	7.63	8.50	9.34	11.29	13.16	15.08	3.0%
India	2.42	2.46	2.60	3.00	3.51	3.99	4.52	2.7%
Other Asia[6]	6.21	6.28	6.39	7.08	7.75	8.38	9.03	1.6%
Middle East	6.11	6.42	7.02	7.59	8.26	8.87	9.45	1.7%
Africa	3.08	3.22	3.49	3.65	3.90	3.99	4.02	1.0%
Brazil	2.27	2.37	2.55	2.63	2.84	3.06	3.32	1.5%
Other Central and South America	3.20	3.35	3.60	3.58	3.73	3.90	4.04	0.8%
Total Non-OECD	**35.54**	**36.85**	**39.46**	**42.34**	**47.10**	**51.45**	**55.77**	**1.8%**
Total Consumption	**85.26**	**86.20**	**86.70**	**89.47**	**94.60**	**99.88**	**105.41**	**0.9%**
OPEC Production[9]	34.67	34.38	34.75	36.35	38.51	40.76	43.63	1.0%
Non-OPEC Production[9]	49.94	50.55	51.96	53.13	56.09	59.11	61.78	0.9%
Net Eurasia Exports	9.15	9.52	10.24	11.30	12.37	12.60	13.25	1.5%
OPEC Market Share (percent)	41.0	40.5	40.1	40.6	40.7	40.8	41.4	- -

[1]Weighted average price delivered to U.S. refiners.
[2]Includes production of crude oil (including lease condensate), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol and other sources, and refinery gains.
[3]OPEC = Organization of Petroleum Exporting Countries - Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[4]OECD Europe = Organization for Economic Cooperation and Development - Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.
[5]Other Europe and Eurasia = Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Serbia, Slovenia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.
[6]Other Asia = Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), Fiji, French Polynesia, Guam, Hong Kong, Indonesia, Kiribati, Laos, Malaysia, Macau, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, and Vietnam.
[7]Includes liquids produced from energy crops, natural gas, coal, extra-heavy oil, oil sands, and shale. Includes both OPEC and non-OPEC producers in the regional breakdown.
[8]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[9]Includes both conventional and unconventional liquids production.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2006 and 2007 imported crude oil price: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2006 quantities derived from: EIA, *International Energy Annual 2006*, DOE/EIA-0219(2006) (Washington, DC, June-October 2008). **2007 quantities and projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A and EIA, Generate World Oil Balance Model.

Economic Growth Case Comparisons

Table B1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2007	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Production										
Crude Oil and Lease Condensate	10.73	12.19	12.19	12.19	13.81	14.06	14.14	15.51	15.96	16.30
Natural Gas Plant Liquids	2.41	2.55	2.58	2.60	2.46	2.57	2.66	2.45	2.61	2.74
Dry Natural Gas	19.84	20.71	20.95	21.11	21.09	22.08	22.86	22.96	24.26	25.41
Coal[1]	23.50	24.20	24.21	24.22	23.92	24.43	24.81	25.21	26.93	28.52
Nuclear Power	8.41	8.45	8.45	8.45	8.77	8.99	9.27	8.53	9.47	10.67
Hydropower	2.46	2.67	2.67	2.67	2.94	2.95	2.97	2.96	2.97	2.98
Biomass[2]	3.23	4.15	4.20	4.23	6.30	6.52	6.70	7.85	8.25	9.16
Other Renewable Energy[3]	0.97	1.52	1.54	1.81	1.65	1.74	2.05	2.04	2.19	2.71
Other[4]	0.94	0.84	0.85	0.84	0.99	1.07	1.20	1.00	1.15	1.37
Total	**72.49**	**77.27**	**77.64**	**78.10**	**81.93**	**84.41**	**86.67**	**88.52**	**93.79**	**99.85**
Imports										
Crude Oil	21.90	17.49	17.76	18.11	15.20	16.09	17.61	13.05	15.39	17.65
Liquid Fuels and Other Petroleum[5]	6.97	5.51	5.59	5.68	5.07	5.67	6.10	5.40	6.33	7.05
Natural Gas	4.72	3.22	3.27	3.32	3.18	3.37	3.63	2.30	2.58	3.03
Other Imports[6]	0.99	0.89	0.89	0.89	1.09	1.19	1.20	1.14	1.35	1.45
Total	**34.59**	**27.11**	**27.51**	**28.00**	**24.54**	**26.31**	**28.55**	**21.89**	**25.65**	**29.18**
Exports										
Petroleum[7]	2.84	2.51	2.56	2.56	2.86	2.90	2.93	3.12	3.17	3.19
Natural Gas	0.83	0.70	0.70	0.70	1.47	1.44	1.41	1.98	1.87	1.79
Coal	1.51	2.05	2.05	2.05	1.35	1.33	1.33	1.16	1.08	1.07
Total	**5.17**	**5.26**	**5.31**	**5.31**	**5.68**	**5.66**	**5.68**	**6.27**	**6.12**	**6.06**
Discrepancy[8]	**0.01**	**-0.03**	**-0.02**	**0.09**	**-0.28**	**-0.39**	**-0.51**	**-0.06**	**-0.25**	**-0.41**
Consumption										
Liquid Fuels and Other Petroleum[9]	40.75	37.55	37.89	38.36	36.94	38.93	41.27	37.42	41.60	45.63
Natural Gas	23.70	22.90	23.20	23.28	22.88	24.09	25.16	23.35	25.04	26.71
Coal[10]	22.74	22.90	22.91	22.92	23.37	23.98	24.35	24.63	26.56	28.23
Nuclear Power	8.41	8.45	8.45	8.45	8.77	8.99	9.27	8.53	9.47	10.67
Hydropower	2.46	2.67	2.67	2.67	2.94	2.95	2.97	2.96	2.97	2.98
Biomass[11]	2.62	2.95	2.99	3.01	4.35	4.58	4.77	5.12	5.51	6.20
Other Renewable Energy[3]	0.97	1.52	1.54	1.81	1.65	1.74	2.05	2.04	2.19	2.71
Other[12]	0.23	0.21	0.21	0.21	0.17	0.19	0.21	0.15	0.22	0.25
Total	**101.89**	**99.15**	**99.85**	**100.70**	**101.07**	**105.44**	**110.06**	**104.20**	**113.56**	**123.38**
Prices (2007 dollars per unit)										
Petroleum (dollars per barrel)										
Imported Low Sulfur Light Crude Oil Price[13]	72.33	77.68	80.16	78.55	113.36	115.45	116.49	127.30	130.43	135.72
Imported Crude Oil Price[13]	63.83	74.76	77.56	75.89	106.41	112.05	113.50	116.58	124.60	131.46
Natural Gas (dollars per million Btu)										
Price at Henry Hub	6.96	6.47	6.66	6.71	6.84	7.43	7.84	8.72	9.25	9.58
Wellhead Price[14]	6.22	5.72	5.88	5.93	6.04	6.56	6.93	7.70	8.17	8.46
Natural Gas (dollars per thousand cubic feet)										
Wellhead Price[14]	6.39	5.88	6.05	6.10	6.21	6.75	7.12	7.92	8.40	8.70
Coal (dollars per ton)										
Minemouth Price[15]	25.82	29.40	29.45	29.61	27.56	27.90	28.25	27.73	29.10	30.12
Coal (dollars per million Btu)										
Minemouth Price[15]	1.27	1.44	1.44	1.45	1.37	1.39	1.41	1.39	1.46	1.51
Average Delivered Price[16]	1.86	1.98	1.99	1.99	1.96	1.99	2.02	2.01	2.08	2.15
Average Electricity Price (cents per kilowatthour)	9.1	8.9	9.0	9.1	8.9	9.4	9.9	9.7	10.4	10.8

Table B1. Total Energy Supply and Disposition Summary (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2007	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Prices (nominal dollars per unit)										
Petroleum (dollars per barrel)										
Imported Low Sulfur Light Crude Oil Price[13]	72.33	82.74	84.42	81.67	158.08	149.14	138.14	209.06	189.10	170.81
Imported Crude Oil Price[13]	63.83	79.63	81.69	78.91	148.39	144.74	134.60	191.46	180.66	165.45
Natural Gas (dollars per million Btu)										
Price at Henry Hub	6.96	6.89	7.01	6.98	9.54	9.60	9.30	14.32	13.42	12.06
Wellhead Price[14]	6.22	6.09	6.19	6.17	8.43	8.48	8.21	12.65	11.85	10.65
Natural Gas (dollars per thousand cubic feet)										
Wellhead Price[14]	6.39	6.26	6.37	6.34	8.66	8.72	8.44	13.00	12.18	10.95
Coal (dollars per ton)										
Minemouth Price[15]	25.82	31.31	31.02	30.79	38.44	36.04	33.50	45.55	42.20	37.91
Coal (dollars per million Btu)										
Minemouth Price[15]	1.27	1.53	1.52	1.51	1.91	1.80	1.67	2.28	2.11	1.90
Average Delivered Price[16]	1.86	2.11	2.10	2.07	2.73	2.57	2.39	3.31	3.01	2.71
Average Electricity Price (cents per kilowatthour)	9.1	9.5	9.5	9.4	12.4	12.2	11.8	16.0	15.1	13.7

[1]Includes waste coal.
[2]Includes grid-connected electricity from wood and waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[3]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy.
[4]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[5]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[6]Includes coal, coal coke (net), and electricity (net).
[7]Includes crude oil and petroleum products.
[8]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[9]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen. Refer to Table A17 for detailed renewable liquid fuels consumption.
[10]Excludes coal converted to coal-based synthetic liquids.
[11]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[12]Includes non-biogenic municipal waste and net electricity imports.
[13]Weighted average price delivered to U.S. refiners.
[14]Represents lower 48 onshore and offshore supplies.
[15]Includes reported prices for both open market and captive mines.
[16]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 natural gas supply values and natural gas wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2007 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2007*, DOE/EIA-0584(2007) (Washington, DC, September 2008). 2007 petroleum supply values: EIA, *Petroleum Supply Annual 2007,* DOE/EIA-0340(2007)/1 (Washington, DC, July 2008). 2007 low sulfur light crude oil price: EIA, Form EIA-856, “Monthly Foreign Crude Oil Acquisition Report.” Other 2007 coal values: *Quarterly Coal Report, October-December 2007*, DOE/EIA-0121(2007/4Q) (Washington, DC, March 2008). Other 2007 values: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** EIA, AEO2009 National Energy Modeling System runs LM2009.D120908A, AEO2009.D120908A, and HM2009.D120908A.

Table B2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2007	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Energy Consumption										
Residential										
Liquefied Petroleum Gases	0.50	0.49	0.49	0.49	0.48	0.49	0.51	0.49	0.52	0.54
Kerosene	0.08	0.08	0.08	0.08	0.07	0.07	0.07	0.07	0.07	0.07
Distillate Fuel Oil	0.78	0.72	0.72	0.72	0.60	0.60	0.60	0.51	0.51	0.51
Liquid Fuels and Other Petroleum Subtotal	1.35	1.29	1.29	1.29	1.15	1.16	1.18	1.07	1.10	1.13
Natural Gas	4.86	4.92	4.92	4.92	5.03	5.10	5.18	4.86	5.07	5.30
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.43	0.43	0.43	0.43	0.47	0.48	0.49	0.48	0.50	0.53
Electricity	4.75	4.78	4.80	4.81	4.98	5.12	5.25	5.34	5.69	6.07
Delivered Energy	**11.40**	**11.43**	**11.44**	**11.46**	**11.63**	**11.86**	**12.11**	**11.75**	**12.36**	**13.03**
Electricity Related Losses	10.36	10.42	10.44	10.49	10.57	10.81	11.04	11.10	11.69	12.29
Total	**21.76**	**21.85**	**21.88**	**21.95**	**22.20**	**22.67**	**23.15**	**22.85**	**24.05**	**25.32**
Commercial										
Liquefied Petroleum Gases	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.10	0.10
Motor Gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate Fuel Oil	0.41	0.36	0.36	0.36	0.34	0.34	0.35	0.34	0.34	0.35
Residual Fuel Oil	0.08	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08
Liquid Fuels and Other Petroleum Subtotal	0.63	0.58	0.58	0.58	0.58	0.58	0.59	0.58	0.59	0.60
Natural Gas	3.10	3.14	3.14	3.14	3.30	3.34	3.40	3.40	3.54	3.70
Coal	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Renewable Energy[3]	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Electricity	4.58	4.74	4.75	4.76	5.42	5.57	5.72	6.01	6.31	6.66
Delivered Energy	**8.50**	**8.65**	**8.66**	**8.67**	**9.48**	**9.69**	**9.90**	**10.18**	**10.62**	**11.14**
Electricity Related Losses	9.99	10.34	10.35	10.38	11.50	11.77	12.02	12.51	12.96	13.49
Total	**18.49**	**18.99**	**19.01**	**19.05**	**20.99**	**21.46**	**21.92**	**22.69**	**23.59**	**24.64**
Industrial[4]										
Liquefied Petroleum Gases	2.35	1.93	2.02	2.12	1.57	1.79	2.03	1.32	1.66	2.04
Motor Gasoline[2]	0.36	0.34	0.34	0.35	0.31	0.34	0.37	0.31	0.36	0.40
Distillate Fuel Oil	1.28	1.15	1.17	1.19	1.08	1.18	1.28	1.08	1.23	1.39
Residual Fuel Oil	0.25	0.15	0.15	0.15	0.15	0.16	0.17	0.14	0.16	0.18
Petrochemical Feedstocks	1.30	0.98	1.01	1.03	0.98	1.13	1.29	0.81	1.05	1.33
Other Petroleum[5]	4.42	3.75	3.74	3.78	3.57	3.72	4.06	3.46	3.84	4.21
Liquid Fuels and Other Petroleum Subtotal	9.96	8.30	8.42	8.62	7.66	8.32	9.21	7.12	8.30	9.55
Natural Gas	6.82	6.59	6.77	6.88	6.32	6.84	7.27	6.05	7.04	8.16
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and Plant Fuel[6]	1.20	1.26	1.27	1.28	1.29	1.33	1.37	1.41	1.47	1.51
Natural Gas Subtotal	8.02	7.85	8.05	8.16	7.61	8.17	8.64	7.45	8.51	9.67
Metallurgical Coal	0.60	0.55	0.55	0.56	0.45	0.49	0.53	0.38	0.48	0.57
Other Industrial Coal	1.21	1.23	1.24	1.24	1.11	1.15	1.19	1.08	1.16	1.23
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.24	0.24	0.24	0.58	0.58	0.59
Net Coal Coke Imports	0.03	0.01	0.01	0.01	0.00	0.01	0.01	0.00	0.01	0.02
Coal Subtotal	1.83	1.79	1.80	1.81	1.81	1.89	1.98	2.05	2.23	2.42
Biofuels Heat and Coproducts	0.40	0.74	0.75	0.75	1.24	1.23	1.22	1.66	1.66	1.92
Renewable Energy[7]	1.64	1.46	1.48	1.50	1.52	1.64	1.76	1.69	1.96	2.24
Electricity	3.43	3.31	3.34	3.37	3.26	3.48	3.71	3.13	3.67	4.23
Delivered Energy	**25.29**	**23.46**	**23.83**	**24.23**	**23.09**	**24.73**	**26.52**	**23.10**	**26.33**	**30.03**
Electricity Related Losses	7.49	7.22	7.27	7.35	6.92	7.36	7.80	6.51	7.55	8.57
Total	**32.77**	**30.68**	**31.10**	**31.58**	**30.01**	**32.09**	**34.33**	**29.61**	**33.87**	**38.60**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2007	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Transportation										
Liquefied Petroleum Gases	0.02	0.01	0.01	0.01	0.01	0.01	0.02	0.01	0.02	0.02
E85[8]	0.00	0.00	0.00	0.00	0.94	0.85	0.75	2.11	2.18	2.38
Motor Gasoline[2]	17.29	16.85	16.93	17.05	14.86	15.56	16.35	13.30	14.49	15.33
Jet Fuel[9]	3.23	2.96	3.00	3.05	3.28	3.42	3.57	3.78	4.12	4.40
Distillate Fuel Oil[10]	6.48	6.04	6.13	6.23	6.82	7.36	7.94	7.78	9.09	10.47
Residual Fuel Oil	0.95	0.85	0.86	0.86	0.97	0.98	0.98	0.98	1.00	1.02
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[11]	0.17	0.17	0.17	0.17	0.17	0.18	0.18	0.18	0.18	0.19
Liquid Fuels and Other Petroleum Subtotal	28.14	26.90	27.11	27.38	27.05	28.36	29.78	28.15	31.09	33.81
Pipeline Fuel Natural Gas	0.64	0.63	0.64	0.65	0.67	0.69	0.71	0.69	0.72	0.75
Compressed Natural Gas	0.02	0.03	0.03	0.03	0.06	0.07	0.07	0.07	0.09	0.10
Electricity	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.05	0.05	0.05
Delivered Energy	**28.82**	**27.59**	**27.81**	**28.08**	**27.81**	**29.15**	**30.59**	**28.95**	**31.94**	**34.72**
Electricity Related Losses	0.05	0.05	0.05	0.05	0.07	0.07	0.07	0.10	0.10	0.11
Total	**28.87**	**27.64**	**27.86**	**28.13**	**27.88**	**29.22**	**30.67**	**29.05**	**32.05**	**34.83**
Delivered Energy Consumption for All Sectors										
Liquefied Petroleum Gases	2.95	2.52	2.61	2.72	2.16	2.39	2.65	1.92	2.29	2.70
E85[8]	0.00	0.00	0.00	0.00	0.94	0.85	0.75	2.11	2.18	2.38
Motor Gasoline[2]	17.70	17.24	17.33	17.44	15.22	15.95	16.77	13.66	14.90	15.79
Jet Fuel[9]	3.23	2.96	3.00	3.05	3.28	3.42	3.57	3.78	4.12	4.40
Kerosene	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Distillate Fuel Oil	8.94	8.27	8.38	8.50	8.84	9.49	10.17	9.70	11.17	12.71
Residual Fuel Oil	1.28	1.07	1.07	1.08	1.20	1.22	1.24	1.21	1.25	1.28
Petrochemical Feedstocks	1.30	0.98	1.01	1.03	0.98	1.13	1.29	0.81	1.05	1.33
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[12]	4.57	3.90	3.89	3.93	3.73	3.89	4.23	3.62	4.01	4.38
Liquid Fuels and Other Petroleum Subtotal	40.08	37.06	37.40	37.87	36.44	38.42	40.76	36.91	41.07	45.09
Natural Gas	14.79	14.69	14.86	14.98	14.70	15.34	15.92	14.38	15.73	17.25
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and Plant Fuel[6]	1.20	1.26	1.27	1.28	1.29	1.33	1.37	1.41	1.47	1.51
Pipeline Natural Gas	0.64	0.63	0.64	0.65	0.67	0.69	0.71	0.69	0.72	0.75
Natural Gas Subtotal	16.64	16.58	16.78	16.90	16.66	17.36	18.00	16.47	17.92	19.52
Metallurgical Coal	0.60	0.55	0.55	0.56	0.45	0.49	0.53	0.38	0.48	0.57
Other Coal	1.28	1.30	1.31	1.32	1.18	1.22	1.27	1.15	1.23	1.31
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.24	0.24	0.24	0.58	0.58	0.59
Net Coal Coke Imports	0.03	0.01	0.01	0.01	0.00	0.01	0.01	0.00	0.01	0.02
Coal Subtotal	1.91	1.86	1.87	1.89	1.88	1.97	2.05	2.12	2.30	2.49
Biofuels Heat and Coproducts	0.40	0.74	0.75	0.75	1.24	1.23	1.22	1.66	1.66	1.92
Renewable Energy[13]	2.19	2.01	2.03	2.05	2.12	2.24	2.38	2.30	2.58	2.89
Electricity	12.79	12.86	12.91	12.98	13.68	14.20	14.72	14.53	15.73	17.01
Delivered Energy	**74.01**	**71.13**	**71.74**	**72.44**	**72.01**	**75.42**	**79.12**	**73.99**	**81.26**	**88.92**
Electricity Related Losses	27.88	28.03	28.11	28.26	29.06	30.02	30.93	30.21	32.30	34.47
Total	**101.89**	**99.15**	**99.85**	**100.70**	**101.07**	**105.44**	**110.06**	**104.20**	**113.56**	**123.38**
Electric Power[14]										
Distillate Fuel Oil	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.13	0.13
Residual Fuel Oil	0.56	0.38	0.38	0.38	0.38	0.39	0.39	0.39	0.40	0.41
Liquid Fuels and Other Petroleum Subtotal	0.67	0.49	0.49	0.49	0.50	0.51	0.51	0.51	0.53	0.54
Natural Gas	7.06	6.32	6.42	6.38	6.22	6.73	7.16	6.87	7.12	7.20
Steam Coal	20.84	21.04	21.03	21.03	21.49	22.01	22.30	22.51	24.25	25.74
Nuclear Power	8.41	8.45	8.45	8.45	8.77	8.99	9.27	8.53	9.47	10.67
Renewable Energy[15]	3.45	4.38	4.42	4.68	5.59	5.79	6.20	6.17	6.43	7.08
Electricity Imports	0.11	0.08	0.08	0.08	0.04	0.06	0.08	0.02	0.10	0.13
Total[16]	**40.67**	**40.89**	**41.02**	**41.24**	**42.74**	**44.22**	**45.65**	**44.74**	**48.03**	**51.48**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2007	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Total Energy Consumption										
Liquefied Petroleum Gases	2.95	2.52	2.61	2.72	2.16	2.39	2.65	1.92	2.29	2.70
E85[8]	0.00	0.00	0.00	0.00	0.94	0.85	0.75	2.11	2.18	2.38
Motor Gasoline[2]	17.70	17.24	17.33	17.44	15.22	15.95	16.77	13.66	14.90	15.79
Jet Fuel[9]	3.23	2.96	3.00	3.05	3.28	3.42	3.57	3.78	4.12	4.40
Kerosene	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Distillate Fuel Oil	9.05	8.39	8.49	8.62	8.96	9.61	10.29	9.83	11.31	12.85
Residual Fuel Oil	1.84	1.45	1.45	1.46	1.58	1.60	1.63	1.60	1.64	1.69
Petrochemical Feedstocks	1.30	0.98	1.01	1.03	0.98	1.13	1.29	0.81	1.05	1.33
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[12]	4.57	3.90	3.89	3.93	3.73	3.89	4.23	3.62	4.01	4.38
Liquid Fuels and Other Petroleum Subtotal	40.75	37.55	37.89	38.36	36.94	38.93	41.27	37.42	41.60	45.63
Natural Gas	21.86	21.01	21.29	21.36	20.92	22.07	23.09	21.25	22.86	24.45
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and Plant Fuel[6]	1.20	1.26	1.27	1.28	1.29	1.33	1.37	1.41	1.47	1.51
Pipeline Natural Gas	0.64	0.63	0.64	0.65	0.67	0.69	0.71	0.69	0.72	0.75
Natural Gas Subtotal	23.70	22.90	23.20	23.28	22.88	24.09	25.16	23.35	25.04	26.71
Metallurgical Coal	0.60	0.55	0.55	0.56	0.45	0.49	0.53	0.38	0.48	0.57
Other Coal	22.12	22.35	22.34	22.35	22.67	23.24	23.57	23.66	25.49	27.04
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.24	0.24	0.24	0.58	0.58	0.59
Net Coal Coke Imports	0.03	0.01	0.01	0.01	0.00	0.01	0.01	0.00	0.01	0.02
Coal Subtotal	22.74	22.90	22.91	22.92	23.37	23.98	24.35	24.63	26.56	28.23
Nuclear Power	8.41	8.45	8.45	8.45	8.77	8.99	9.27	8.53	9.47	10.67
Biofuels Heat and Coproducts	0.40	0.74	0.75	0.75	1.24	1.23	1.22	1.66	1.66	1.92
Renewable Energy[17]	5.65	6.40	6.45	6.74	7.71	8.03	8.57	8.47	9.01	9.97
Electricity Imports	0.11	0.08	0.08	0.08	0.04	0.06	0.08	0.02	0.10	0.13
Total	**101.89**	**99.15**	**99.85**	**100.70**	**101.07**	**105.44**	**110.06**	**104.20**	**113.56**	**123.38**
Energy Use and Related Statistics										
Delivered Energy Use	74.01	71.13	71.74	72.44	72.01	75.42	79.12	73.99	81.26	88.92
Total Energy Use	101.89	99.15	99.85	100.70	101.07	105.44	110.06	104.20	113.56	123.38
Ethanol Consumed in Motor Gasoline and E85	0.56	1.08	1.08	1.09	1.67	1.66	1.65	2.34	2.47	2.67
Population (millions)	302.41	309.98	311.37	313.17	330.15	342.61	356.39	345.43	375.12	406.67
Gross Domestic Product (billion 2000 dollars)	11524	11453	11779	12114	14327	15524	16726	17351	20114	22875
Carbon Dioxide Emissions (million metric tons)	5990.8	5769.9	5801.4	5831.1	5745.9	5982.3	6209.9	5897.9	6414.4	6885.9

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol blends (10 percent or less) in motor gasoline.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes only kerosene type.
[10]Diesel fuel for on- and off- road use.
[11]Includes aviation gasoline and lubricants.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[16]Includes non-biogenic municipal waste not included above.
[17]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2007 population and gross domestic product: IHS Global Insight Industry and Employment models, November 2008. 2007 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2007,* DOE/EIA-0573(2007) (Washington, DC, December 2008). **Projections:** EIA, AEO2009 National Energy Modeling System runs LM2009.D120908A, AEO2009.D120908A, and HM2009.D120908A.

Table B3. Energy Prices by Sector and Source
(2007 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2007	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Residential										
Liquefied Petroleum Gases	24.98	25.33	25.86	25.52	31.79	32.88	33.08	33.52	35.11	36.58
Distillate Fuel Oil	19.66	18.23	18.69	18.38	22.98	24.10	24.43	25.16	26.67	28.13
Natural Gas	12.69	11.90	12.09	12.18	11.89	12.50	12.91	13.72	14.31	14.69
Electricity	31.19	30.65	30.89	31.07	31.22	32.72	34.31	33.52	35.84	37.37
Commercial										
Liquefied Petroleum Gases	23.04	22.15	22.69	22.34	28.54	29.60	29.79	30.22	31.77	33.21
Distillate Fuel Oil	16.05	15.68	16.15	15.83	21.04	22.11	22.45	23.07	24.69	26.13
Residual Fuel Oil	10.21	10.52	10.97	10.67	16.20	16.68	16.81	17.64	17.98	18.38
Natural Gas	10.99	10.36	10.55	10.63	10.47	11.13	11.60	12.27	12.96	13.42
Electricity	28.07	27.00	27.29	27.52	26.41	28.15	29.82	28.68	31.01	32.54
Industrial[1]										
Liquefied Petroleum Gases	23.38	21.29	21.84	21.48	27.76	28.78	28.95	29.31	30.99	32.44
Distillate Fuel Oil	16.82	15.54	16.01	15.69	21.53	22.56	22.92	23.51	25.19	26.62
Residual Fuel Oil	10.49	14.92	15.38	15.09	20.08	20.94	21.19	21.64	22.73	23.87
Natural Gas[2]	7.52	6.76	6.91	6.95	6.95	7.48	7.83	8.62	9.07	9.39
Metallurgical Coal	3.61	4.37	4.37	4.39	4.33	4.40	4.44	4.36	4.41	4.48
Other Industrial Coal	2.43	2.53	2.54	2.54	2.50	2.53	2.57	2.56	2.67	2.76
Coal to Liquids	- -	- -	- -	- -	1.23	1.23	1.26	1.48	1.36	1.39
Electricity	18.63	18.51	18.72	18.88	17.78	19.06	20.50	19.62	21.59	22.60
Transportation										
Liquefied Petroleum Gases[3]	25.01	25.13	25.67	25.33	31.53	32.62	32.83	33.20	34.77	36.24
E85[4]	26.67	24.93	25.47	25.14	28.24	29.30	29.62	28.65	30.10	30.94
Motor Gasoline[5]	22.98	22.99	23.47	23.17	28.68	29.75	30.14	30.42	32.10	33.71
Jet Fuel[6]	16.10	15.54	16.03	15.71	21.27	22.15	22.50	23.23	24.63	25.95
Diesel Fuel (distillate fuel oil)[7]	20.92	19.55	20.05	19.74	24.96	26.04	26.53	26.75	28.59	30.20
Residual Fuel Oil	9.35	11.65	12.10	11.86	16.66	17.46	17.68	18.70	19.65	20.87
Natural Gas[8]	15.46	14.71	14.90	14.99	14.20	14.90	15.46	15.53	16.24	16.82
Electricity	30.64	29.99	30.34	30.56	27.79	29.48	31.35	31.10	34.15	35.68
Electric Power[9]										
Distillate Fuel Oil	14.77	14.64	15.09	14.79	19.42	20.45	20.78	21.69	23.11	24.53
Residual Fuel Oil	8.38	12.75	13.21	12.94	17.77	18.55	18.79	19.71	20.67	21.81
Natural Gas	7.02	6.40	6.59	6.65	6.59	7.15	7.53	8.23	8.70	9.02
Steam Coal	1.78	1.89	1.89	1.89	1.89	1.92	1.94	1.97	2.04	2.11
Average Price to All Users[10]										
Liquefied Petroleum Gases	18.53	20.52	20.96	20.60	26.70	27.56	27.64	28.53	29.77	30.85
E85[4]	26.67	24.93	25.47	25.14	28.24	29.30	29.62	28.65	30.10	30.94
Motor Gasoline[5]	22.82	22.99	23.47	23.17	28.68	29.75	30.14	30.42	32.10	33.70
Jet Fuel	16.10	15.54	16.03	15.71	21.27	22.15	22.50	23.23	24.63	25.95
Distillate Fuel Oil	19.94	18.49	18.98	18.68	24.18	25.28	25.74	26.12	27.94	29.55
Residual Fuel Oil	9.25	12.21	12.66	12.41	17.22	18.03	18.26	19.16	20.12	21.29
Natural Gas	9.01	8.40	8.56	8.62	8.61	9.11	9.46	10.27	10.75	11.07
Metallurgical Coal	3.61	4.37	4.37	4.39	4.33	4.40	4.44	4.36	4.41	4.48
Other Coal	1.82	1.93	1.93	1.93	1.93	1.95	1.98	2.00	2.07	2.14
Coal to Liquids	- -	- -	- -	- -	1.23	1.23	1.26	1.48	1.36	1.39
Electricity	26.70	26.18	26.42	26.60	26.11	27.57	29.07	28.52	30.56	31.80
Non-Renewable Energy Expenditures by Sector (billion 2007 dollars)										
Residential	238.38	232.16	235.27	236.76	245.77	263.30	280.31	276.47	310.03	340.96
Commercial	173.09	170.43	172.88	174.43	190.63	207.76	224.08	228.34	256.75	282.60
Industrial	226.84	195.79	204.25	208.24	209.85	242.68	274.85	217.46	276.26	339.95
Transportation	596.75	563.59	580.97	578.11	687.05	752.82	806.73	724.88	853.25	976.29
Total Non-Renewable Expenditures	1235.06	1161.96	1193.36	1197.55	1333.29	1466.55	1585.97	1447.15	1696.29	1939.79
Transportation Renewable Expenditures	0.04	0.06	0.07	0.07	26.65	24.83	22.10	60.50	65.71	73.63
Total Expenditures	**1235.10**	**1162.03**	**1193.43**	**1197.61**	**1359.95**	**1491.38**	**1608.07**	**1507.65**	**1762.00**	**2013.43**

Table B3. Energy Prices by Sector and Source (Continued)
(Nominal Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2007	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Residential										
Liquefied Petroleum Gases	24.98	26.98	27.24	26.53	44.34	42.47	39.23	55.06	50.90	46.04
Distillate Fuel Oil	19.66	19.42	19.68	19.11	32.05	31.14	28.97	41.32	38.67	35.40
Natural Gas	12.69	12.67	12.74	12.66	16.58	16.14	15.31	22.53	20.75	18.49
Electricity	31.19	32.65	32.53	32.31	43.54	42.26	40.69	55.05	51.96	47.03
Commercial										
Liquefied Petroleum Gases	23.04	23.59	23.89	23.23	39.80	38.24	35.32	49.63	46.06	41.79
Distillate Fuel Oil	16.05	16.70	17.01	16.46	29.35	28.56	26.62	37.88	35.80	32.89
Residual Fuel Oil	10.21	11.20	11.55	11.10	22.59	21.55	19.94	28.97	26.07	23.13
Natural Gas	10.99	11.03	11.11	11.05	14.60	14.37	13.75	20.16	18.78	16.89
Electricity	28.07	28.76	28.74	28.62	36.83	36.37	35.37	47.10	44.96	40.95
Industrial[1]										
Liquefied Petroleum Gases	23.38	22.68	23.00	22.34	38.71	37.17	34.32	48.13	44.93	40.82
Distillate Fuel Oil	16.82	16.55	16.86	16.32	30.03	29.14	27.18	38.61	36.52	33.50
Residual Fuel Oil	10.49	15.89	16.20	15.69	28.00	27.05	25.13	35.54	32.95	30.04
Natural Gas[2]	7.52	7.20	7.27	7.23	9.70	9.66	9.29	14.15	13.16	11.82
Metallurgical Coal	3.61	4.65	4.60	4.57	6.04	5.69	5.27	7.17	6.40	5.64
Other Industrial Coal	2.43	2.69	2.67	2.64	3.49	3.27	3.04	4.20	3.88	3.47
Coal to Liquids	- -	- -	- -	- -	1.72	1.59	1.49	2.44	1.98	1.75
Electricity	18.63	19.72	19.72	19.63	24.79	24.63	24.30	32.22	31.30	28.44
Transportation										
Liquefied Petroleum Gases[3]	25.01	26.77	27.04	26.34	43.98	42.13	38.93	54.52	50.41	45.61
E85[4]	26.67	26.55	26.83	26.14	39.38	37.85	35.12	47.06	43.63	38.94
Motor Gasoline[5]	22.98	24.49	24.72	24.09	40.00	38.43	35.75	49.96	46.54	42.42
Jet Fuel[6]	16.10	16.55	16.89	16.34	29.66	28.62	26.68	38.15	35.70	32.66
Diesel Fuel (distillate fuel oil)[7]	20.92	20.82	21.12	20.52	34.81	33.63	31.47	43.93	41.44	38.00
Residual Fuel Oil	9.35	12.41	12.74	12.33	23.23	22.56	20.96	30.72	28.49	26.27
Natural Gas[8]	15.46	15.67	15.69	15.59	19.80	19.24	18.33	25.50	23.55	21.17
Electricity	30.64	31.94	31.95	31.78	38.75	38.09	37.18	51.07	49.51	44.90
Electric Power[9]										
Distillate Fuel Oil	14.77	15.59	15.89	15.38	27.07	26.42	24.64	35.62	33.51	30.87
Residual Fuel Oil	8.38	13.58	13.91	13.46	24.78	23.97	22.28	32.36	29.97	27.44
Natural Gas	7.02	6.82	6.94	6.92	9.19	9.24	8.94	13.51	12.61	11.35
Steam Coal	1.78	2.01	1.99	1.97	2.64	2.48	2.30	3.24	2.95	2.65

Table B3. Energy Prices by Sector and Source (Continued)
(Nominal Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2007	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Average Price to All Users[10]										
Liquefied Petroleum Gases	18.53	21.85	22.07	21.42	37.24	35.61	32.78	46.86	43.16	38.83
E85[4]	26.67	26.55	26.83	26.14	39.38	37.85	35.12	47.06	43.63	38.94
Motor Gasoline[5]	22.82	24.49	24.71	24.09	40.00	38.43	35.74	49.95	46.54	42.42
Jet Fuel	16.10	16.55	16.89	16.34	29.66	28.62	26.68	38.15	35.70	32.66
Distillate Fuel Oil	19.94	19.69	19.99	19.42	33.72	32.65	30.53	42.89	40.51	37.19
Residual Fuel Oil	9.25	13.00	13.34	12.91	24.02	23.29	21.66	31.46	29.16	26.80
Natural Gas	9.01	8.95	9.01	8.96	12.00	11.77	11.22	16.86	15.58	13.93
Metallurgical Coal	3.61	4.65	4.60	4.57	6.04	5.69	5.27	7.17	6.40	5.64
Other Coal	1.82	2.05	2.04	2.01	2.69	2.52	2.34	3.29	3.00	2.69
Coal to Liquids	- -	- -	- -	- -	1.72	1.59	1.49	2.44	1.98	1.75
Electricity	26.70	27.88	27.82	27.66	36.41	35.62	34.48	46.83	44.31	40.02
Non-Renewable Energy Expenditures by Sector (billion nominal dollars)										
Residential	238.38	247.28	247.78	246.19	342.73	340.12	332.40	454.04	449.49	429.11
Commercial	173.09	181.52	182.07	181.38	265.84	268.38	265.72	375.00	372.25	355.66
Industrial	226.84	208.54	215.12	216.54	292.64	313.49	325.93	357.14	400.54	427.84
Transportation	596.75	600.28	611.87	601.14	958.10	972.48	956.66	1190.47	1237.08	1228.71
Total Non-Renewable Expenditures	1235.06	1237.62	1256.84	1245.25	1859.30	1894.47	1880.71	2376.64	2459.36	2441.32
Transportation Renewable Expenditures	0.04	0.07	0.07	0.07	37.17	32.08	26.21	99.35	95.27	92.67
Total Expenditures	**1235.10**	**1237.69**	**1256.91**	**1245.32**	**1896.47**	**1926.55**	**1906.92**	**2476.00**	**2554.63**	**2533.99**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Excludes use for lease and plant fuel.
[3]Includes Federal and State taxes while excluding county and local taxes.
[4]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[5]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[8]Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[9]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[10]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 2007*, DOE/EIA-0487(2007) (Washington, DC, August 2008). 2007 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2007 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007) and the *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2007 transportation sector natural gas delivered prices are model results. 2007 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2007 and April 2008, Table 4.13.B. 2007 coal prices based on: EIA, *Quarterly Coal Report, October-December 2007*, DOE/EIA-0121(2007/4Q) (Washington, DC, March 2008) and EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A. 2007 electricity prices: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2007 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report.
Projections: EIA, AEO2009 National Energy Modeling System runs LM2009.D120908A, AEO2009.D120908A, and HM2009.D120908A.

Table B4. Macroeconomic Indicators
(Billion 2000 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	2007	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Real Gross Domestic Product	**11524**	**11453**	**11779**	**12114**	**14327**	**15524**	**16726**	**17351**	**20114**	**22875**
Components of Real Gross Domestic Product										
Real Consumption	8253	8270	8435	8607	10121	10876	11639	11826	13439	15054
Real Investment	1810	1438	1581	1728	2270	2565	2856	3004	3756	4478
Real Government Spending	2012	2033	2065	2096	2058	2194	2329	2129	2427	2722
Real Exports	1426	1574	1585	1597	2765	3061	3365	4906	5820	6757
Real Imports	1972	1861	1899	1947	2874	3007	3111	4413	4717	4961
Energy Intensity (thousand Btu per 2000 dollar of GDP)										
Delivered Energy	6.42	6.21	6.09	5.98	5.03	4.86	4.73	4.26	4.04	3.89
Total Energy	8.84	8.66	8.48	8.31	7.05	6.79	6.58	6.01	5.65	5.39
Price Indices										
GDP Chain-Type Price Index (2000=1.000)	1.198	1.276	1.262	1.246	1.671	1.548	1.421	1.968	1.737	1.508
Consumer Price Index (1982-4=1)										
All-Urban	2.07	2.22	2.20	2.17	3.05	2.83	2.60	3.74	3.31	2.88
Energy Commodities and Services	2.08	2.17	2.18	2.15	3.28	3.16	2.97	4.14	3.87	3.51
Wholesale Price Index (1982=1.00)										
All Commodities	1.73	1.82	1.80	1.76	2.39	2.19	1.98	2.75	2.36	1.99
Fuel and Power	1.77	1.90	1.91	1.88	2.82	2.74	2.60	3.70	3.45	3.14
Metals and Metal Products	1.93	1.84	1.82	1.80	2.37	2.21	2.05	2.50	2.22	1.97
Interest Rates (percent, nominal)										
Federal Funds Rate	5.02	1.36	1.30	1.15	5.72	5.20	4.63	4.49	4.04	3.60
10-Year Treasury Note	4.63	3.89	3.67	3.36	6.43	5.86	5.24	5.19	4.67	4.18
AA Utility Bond Rate	5.94	6.56	6.39	6.12	8.06	7.49	6.86	6.35	5.79	5.24
Value of Shipments (billion 2000 dollars)										
Total Industrial	5750	5069	5240	5418	6132	6753	7383	6923	8451	10032
Non-manufacturing	1490	1196	1277	1361	1411	1603	1795	1498	1780	2057
Manufacturing	4261	3873	3963	4058	4721	5150	5588	5425	6671	7975
Energy-Intensive	1239	1215	1238	1265	1277	1374	1481	1319	1525	1743
Non-Energy Intensive	3022	2658	2725	2793	3444	3776	4106	4106	5145	6232
Population and Employment (millions)										
Population with Armed Forces Overseas	302.4	310.0	311.4	313.2	330.2	342.6	356.4	345.4	375.1	406.7
Population (aged 16 and over)	237.2	243.8	245.2	247.0	261.8	270.4	279.7	278.2	297.6	318.3
Population, over age 65	38.0	40.2	40.4	40.5	54.2	55.0	56.0	69.9	72.3	74.8
Employment, Nonfarm	137.2	130.7	135.6	140.6	141.7	152.6	163.5	153.1	168.3	183.5
Employment, Manufacturing	13.9	12.0	12.2	12.4	11.8	12.3	12.6	10.7	11.7	12.6
Key Labor Indicators										
Labor Force (millions)	153.1	154.2	155.9	157.4	162.9	168.4	174.5	171.9	181.5	191.4
Non-farm Labor Productivity (1992=1.00)	1.37	1.43	1.45	1.47	1.65	1.74	1.84	1.92	2.14	2.36
Unemployment Rate (percent)	4.64	8.42	8.26	8.08	5.72	5.53	5.30	4.98	4.78	4.58
Key Indicators for Energy Demand										
Real Disposable Personal Income	8644	8837	9017	9209	11317	12035	12757	13927	15450	16980
Housing Starts (millions)	1.44	1.01	1.18	1.37	1.40	1.77	2.16	1.18	1.74	2.31
Commercial Floorspace (billion square feet)	77.3	80.9	81.2	81.4	88.3	92.3	96.2	96.2	103.3	110.6
Unit Sales of Light-Duty Vehicles (millions)	16.09	13.90	14.18	14.89	16.30	17.41	18.88	18.52	20.99	23.77

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2007: IHS Global Insight Industry and Employment models, November 2008. **Projections:** Energy Information Administration, AEO2009 National Energy Modeling System runs LM2009.D120908A, AEO2009.D120908A, and HM2009.D120908A.

Price Case Comparisons

Table C1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Production										
Crude Oil and Lease Condensate	10.73	12.19	12.19	12.20	11.60	14.06	15.54	11.60	15.96	18.31
Natural Gas Plant Liquids	2.41	2.60	2.58	2.57	2.55	2.57	2.59	2.42	2.61	2.67
Dry Natural Gas	19.84	21.09	20.95	20.88	21.20	22.08	22.47	22.86	24.26	26.04
Coal[1]	23.50	24.22	24.21	24.18	24.89	24.43	24.03	26.18	26.93	26.40
Nuclear Power	8.41	8.45	8.45	8.45	8.89	8.99	9.10	9.14	9.47	9.57
Hydropower	2.46	2.67	2.67	2.67	2.97	2.95	2.95	2.98	2.97	2.98
Biomass[2]	3.23	4.20	4.20	4.23	6.28	6.52	7.50	7.81	8.25	8.63
Other Renewable Energy[3]	0.97	1.50	1.54	1.59	1.71	1.74	1.77	2.22	2.19	2.20
Other[4]	0.94	0.85	0.85	0.89	1.07	1.07	1.28	1.15	1.15	1.21
Total	**72.49**	**77.77**	**77.64**	**77.66**	**81.15**	**84.41**	**87.24**	**86.37**	**93.79**	**98.02**
Imports										
Crude Oil	21.90	18.05	17.76	17.59	21.51	16.09	12.08	24.99	15.39	9.64
Liquid Fuels and Other Petroleum[5]	6.97	6.07	5.59	5.53	7.07	5.67	5.33	7.58	6.33	5.74
Natural Gas	4.72	3.27	3.27	3.27	3.90	3.37	3.21	3.27	2.58	2.15
Other Imports[6]	0.99	0.89	0.89	0.89	0.57	1.19	1.43	1.12	1.35	1.67
Total	**34.59**	**28.28**	**27.51**	**27.28**	**33.06**	**26.31**	**22.05**	**36.96**	**25.65**	**19.19**
Exports										
Petroleum[7]	2.84	2.58	2.56	2.55	2.81	2.90	2.90	3.18	3.17	2.96
Natural Gas	0.83	0.70	0.70	0.70	1.48	1.44	1.41	1.97	1.87	1.80
Coal	1.51	2.05	2.05	2.05	1.34	1.33	1.23	1.09	1.08	0.82
Total	**5.17**	**5.33**	**5.31**	**5.30**	**5.64**	**5.66**	**5.54**	**6.24**	**6.12**	**5.57**
Discrepancy[8]	**0.01**	**-0.09**	**-0.02**	**0.01**	**-0.52**	**-0.39**	**-0.25**	**-0.52**	**-0.25**	**-0.16**
Consumption										
Liquid Fuels and Other Petroleum[9]	40.75	38.73	37.89	37.72	43.21	38.93	36.87	47.48	41.60	38.83
Natural Gas	23.70	23.34	23.20	23.10	23.70	24.09	24.18	24.23	25.04	25.72
Coal[10]	22.74	22.92	22.91	22.88	23.93	23.98	23.86	25.99	26.56	26.53
Nuclear Power	8.41	8.45	8.45	8.45	8.89	8.99	9.10	9.14	9.47	9.57
Hydropower	2.46	2.67	2.67	2.67	2.97	2.95	2.95	2.98	2.97	2.98
Biomass[11]	2.62	2.99	2.99	3.00	4.51	4.58	5.04	5.35	5.51	5.72
Other Renewable Energy[3]	0.97	1.50	1.54	1.59	1.71	1.74	1.77	2.22	2.19	2.20
Other[12]	0.23	0.21	0.21	0.22	0.17	0.19	0.22	0.21	0.22	0.25
Total	**101.89**	**100.80**	**99.85**	**99.62**	**109.09**	**105.44**	**104.00**	**117.61**	**113.56**	**111.80**
Prices (2007 dollars per unit)										
Petroleum (dollars per barrel)										
Imported Low Sulfur Light Crude Oil Price[13]	72.33	58.61	80.16	91.08	50.43	115.45	184.60	50.23	130.43	200.42
Imported Crude Oil Price[13]	63.83	55.45	77.56	88.31	46.77	112.05	181.18	46.44	124.60	197.72
Natural Gas (dollars per million Btu)										
Price at Henry Hub	6.96	6.08	6.66	6.89	6.93	7.43	7.80	8.70	9.25	9.62
Wellhead Price[14]	6.22	5.37	5.88	6.09	6.12	6.56	6.89	7.68	8.17	8.49
Natural Gas (dollars per thousand cubic feet)										
Wellhead Price[14]	6.39	5.52	6.05	6.26	6.29	6.75	7.09	7.90	8.40	8.73
Coal (dollars per ton)										
Minemouth Price[15]	25.82	28.93	29.45	29.75	26.97	27.90	29.13	27.41	29.10	29.85
Coal (dollars per million Btu)										
Minemouth Price[15]	1.27	1.42	1.44	1.46	1.34	1.39	1.45	1.37	1.46	1.50
Average Delivered Price[16]	1.86	1.94	1.99	2.02	1.89	1.99	2.10	1.96	2.08	2.18
Average Electricity Price (cents per kilowatthour)	9.1	8.8	9.0	9.1	9.1	9.4	9.7	10.1	10.4	10.6

Table C1. Total Energy Supply and Disposition Summary (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Prices (nominal dollars per unit)										
Petroleum (dollars per barrel)										
Imported Low Sulfur Light Crude Oil Price[13]	72.33	61.54	84.42	95.98	65.49	149.14	237.86	72.62	189.10	289.12
Imported Crude Oil Price[13]	63.83	58.23	81.69	93.06	60.74	144.74	233.45	67.13	180.66	285.22
Natural Gas (dollars per million Btu)										
Price at Henry Hub	6.96	6.38	7.01	7.26	8.99	9.60	10.05	12.58	13.42	13.87
Wellhead Price[14]	6.22	5.64	6.19	6.41	7.95	8.48	8.88	11.11	11.85	12.25
Natural Gas (dollars per thousand cubic feet)										
Wellhead Price[14]	6.39	5.80	6.37	6.59	8.17	8.72	9.13	11.42	12.18	12.60
Coal (dollars per ton)										
Minemouth Price[15]	25.82	30.38	31.02	31.35	35.03	36.04	37.53	39.62	42.20	43.06
Coal (dollars per million Btu)										
Minemouth Price[15]	1.27	1.49	1.52	1.53	1.74	1.80	1.87	1.97	2.11	2.16
Average Delivered Price[16]	1.86	2.04	2.10	2.13	2.45	2.57	2.70	2.83	3.01	3.14
Average Electricity Price (cents per kilowatthour)	9.1	9.3	9.5	9.6	11.8	12.2	12.6	14.6	15.1	15.3

[1]Includes waste coal.
[2]Includes grid-connected electricity from wood and waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[3]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy.
[4]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[5]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[6]Includes coal, coal coke (net), and electricity (net).
[7]Includes crude oil and petroleum products.
[8]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[9]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen. Refer to Table A17 for detailed renewable liquid fuels consumption.
[10]Excludes coal converted to coal-based synthetic liquids.
[11]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[12]Includes non-biogenic municipal waste and net electricity imports.
[13]Weighted average price delivered to U.S. refiners.
[14]Represents lower 48 onshore and offshore supplies.
[15]Includes reported prices for both open market and captive mines.
[16]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 natural gas supply values and natural gas wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2007 coal minemouth and delivered coal prices: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2007 petroleum supply values: EIA, *Petroleum Supply Annual 2007,* DOE/EIA-0340(2007)/1 (Washington, DC, July 2008). 2007 low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2007 coal values: *Quarterly Coal Report, October-December 2007*, DOE/EIA-0121(2007/4Q) (Washington, DC, March 2008). Other 2007 values: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** EIA, AEO2009 National Energy Modeling System runs LP2009.D122308A, AEO2009.D120908A, and HP2009.D121108A.

Table C2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Energy Consumption										
Residential										
Liquefied Petroleum Gases	0.50	0.50	0.49	0.49	0.56	0.49	0.45	0.62	0.52	0.46
Kerosene	0.08	0.08	0.08	0.07	0.08	0.07	0.07	0.08	0.07	0.07
Distillate Fuel Oil	0.78	0.73	0.72	0.71	0.68	0.60	0.54	0.61	0.51	0.46
Liquid Fuels and Other Petroleum Subtotal	1.35	1.31	1.29	1.27	1.32	1.16	1.06	1.31	1.10	0.99
Natural Gas	4.86	4.94	4.92	4.91	5.15	5.10	5.06	5.08	5.07	5.06
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.43	0.42	0.43	0.44	0.40	0.48	0.55	0.40	0.50	0.57
Electricity	4.75	4.81	4.80	4.79	5.16	5.12	5.07	5.74	5.69	5.65
Delivered Energy	**11.40**	**11.49**	**11.44**	**11.42**	**12.05**	**11.86**	**11.75**	**12.53**	**12.36**	**12.29**
Electricity Related Losses	10.36	10.44	10.44	10.44	10.87	10.81	10.72	11.72	11.69	11.59
Total	**21.76**	**21.93**	**21.88**	**21.86**	**22.92**	**22.67**	**22.46**	**24.25**	**24.05**	**23.88**
Commercial										
Liquefied Petroleum Gases	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.10	0.10
Motor Gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate Fuel Oil	0.41	0.37	0.36	0.35	0.41	0.34	0.30	0.44	0.34	0.30
Residual Fuel Oil	0.08	0.08	0.07	0.07	0.09	0.08	0.08	0.09	0.08	0.08
Liquid Fuels and Other Petroleum Subtotal	0.63	0.60	0.58	0.56	0.66	0.58	0.54	0.70	0.59	0.54
Natural Gas	3.10	3.16	3.14	3.13	3.41	3.34	3.30	3.53	3.54	3.54
Coal	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Renewable Energy[3]	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Electricity	4.58	4.76	4.75	4.75	5.65	5.57	5.51	6.36	6.31	6.29
Delivered Energy	**8.50**	**8.72**	**8.66**	**8.64**	**9.90**	**9.69**	**9.54**	**10.77**	**10.62**	**10.56**
Electricity Related Losses	9.99	10.33	10.35	10.35	11.89	11.77	11.65	12.99	12.96	12.89
Total	**18.49**	**19.05**	**19.01**	**18.99**	**21.79**	**21.46**	**21.19**	**23.76**	**23.59**	**23.45**
Industrial[4]										
Liquefied Petroleum Gases	2.35	2.06	2.02	1.99	1.82	1.79	1.76	1.68	1.66	1.66
Motor Gasoline[2]	0.36	0.35	0.34	0.34	0.34	0.34	0.34	0.37	0.36	0.36
Distillate Fuel Oil	1.28	1.18	1.17	1.16	1.21	1.18	1.18	1.29	1.23	1.23
Residual Fuel Oil	0.25	0.16	0.15	0.14	0.22	0.16	0.14	0.32	0.16	0.15
Petrochemical Feedstocks	1.30	1.03	1.01	1.00	1.14	1.13	1.12	1.08	1.05	1.06
Other Petroleum[5]	4.42	4.04	3.74	3.66	4.83	3.72	3.03	5.41	3.84	3.01
Liquid Fuels and Other Petroleum Subtotal	9.96	8.82	8.42	8.29	9.57	8.32	7.57	10.16	8.30	7.46
Natural Gas	6.82	6.64	6.77	6.80	6.17	6.84	7.28	6.06	7.04	7.45
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.00	0.00	0.49
Lease and Plant Fuel[6]	1.20	1.28	1.27	1.27	1.27	1.33	1.37	1.39	1.47	1.57
Natural Gas Subtotal	8.02	7.92	8.05	8.07	7.44	8.17	8.77	7.45	8.51	9.51
Metallurgical Coal	0.60	0.57	0.55	0.54	0.52	0.49	0.47	0.51	0.48	0.46
Other Industrial Coal	1.21	1.25	1.24	1.23	1.16	1.15	1.14	1.17	1.16	1.15
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.10	0.24	0.26	0.10	0.58	0.65
Net Coal Coke Imports	0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Coal Subtotal	1.83	1.83	1.80	1.79	1.79	1.89	1.88	1.79	2.23	2.27
Biofuels Heat and Coproducts	0.40	0.75	0.75	0.75	1.23	1.23	1.69	1.64	1.66	1.81
Renewable Energy[7]	1.64	1.50	1.48	1.48	1.66	1.64	1.62	1.99	1.96	1.93
Electricity	3.43	3.39	3.34	3.32	3.55	3.48	3.46	3.73	3.67	3.66
Delivered Energy	**25.29**	**24.21**	**23.83**	**23.70**	**25.24**	**24.73**	**24.99**	**26.75**	**26.33**	**26.65**
Electricity Related Losses	7.49	7.37	7.27	7.24	7.46	7.36	7.30	7.61	7.55	7.50
Total	**32.77**	**31.58**	**31.10**	**30.94**	**32.70**	**32.09**	**32.29**	**34.37**	**33.87**	**34.15**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Transportation										
Liquefied Petroleum Gases	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.01
E85[8]	0.00	0.00	0.00	0.00	0.60	0.85	1.74	0.58	2.18	2.73
Motor Gasoline[2]	17.29	17.21	16.93	16.96	18.07	15.56	13.68	19.09	14.49	12.41
Jet Fuel[9]	3.23	3.04	3.00	2.98	3.51	3.42	3.33	4.23	4.12	3.96
Distillate Fuel Oil[10]	6.48	6.20	6.13	6.10	7.53	7.36	7.26	9.21	9.09	9.00
Residual Fuel Oil	0.95	0.86	0.86	0.86	0.97	0.98	0.98	1.00	1.00	1.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[11]	0.17	0.17	0.17	0.17	0.18	0.18	0.18	0.18	0.18	0.18
Liquid Fuels and Other Petroleum Subtotal	28.14	27.50	27.11	27.09	30.88	28.36	27.18	34.32	31.09	29.31
Pipeline Fuel Natural Gas	0.64	0.65	0.64	0.64	0.66	0.69	0.69	0.71	0.72	0.72
Compressed Natural Gas	0.02	0.03	0.03	0.03	0.06	0.07	0.07	0.07	0.09	0.10
Electricity	0.02	0.02	0.02	0.02	0.03	0.03	0.04	0.04	0.05	0.06
Delivered Energy	**28.82**	**28.20**	**27.81**	**27.78**	**31.62**	**29.15**	**27.98**	**35.14**	**31.94**	**30.19**
Electricity Related Losses	0.05	0.05	0.05	0.05	0.06	0.07	0.07	0.09	0.10	0.12
Total	**28.87**	**28.25**	**27.86**	**27.83**	**31.68**	**29.22**	**28.05**	**35.23**	**32.05**	**30.32**
Delivered Energy Consumption for All Sectors										
Liquefied Petroleum Gases	2.95	2.67	2.61	2.58	2.49	2.39	2.32	2.42	2.29	2.24
E85[8]	0.00	0.00	0.00	0.00	0.60	0.85	1.74	0.58	2.18	2.73
Motor Gasoline[2]	17.70	17.60	17.33	17.35	18.46	15.95	14.08	19.51	14.90	12.82
Jet Fuel[9]	3.23	3.04	3.00	2.98	3.51	3.42	3.33	4.23	4.12	3.96
Kerosene	0.11	0.11	0.10	0.10	0.11	0.10	0.10	0.11	0.10	0.10
Distillate Fuel Oil	8.94	8.49	8.38	8.33	9.84	9.49	9.28	11.55	11.17	10.99
Residual Fuel Oil	1.28	1.11	1.07	1.06	1.29	1.22	1.20	1.41	1.25	1.23
Petrochemical Feedstocks	1.30	1.03	1.01	1.00	1.14	1.13	1.12	1.08	1.05	1.06
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[12]	4.57	4.19	3.89	3.81	4.99	3.89	3.19	5.58	4.01	3.18
Liquid Fuels and Other Petroleum Subtotal	40.08	38.23	37.40	37.23	42.43	38.42	36.36	46.48	41.07	38.30
Natural Gas	14.79	14.77	14.86	14.88	14.78	15.34	15.72	14.74	15.73	16.16
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.00	0.00	0.49
Lease and Plant Fuel[6]	1.20	1.28	1.27	1.27	1.27	1.33	1.37	1.39	1.47	1.57
Pipeline Natural Gas	0.64	0.65	0.64	0.64	0.66	0.69	0.69	0.71	0.72	0.72
Natural Gas Subtotal	16.64	16.70	16.78	16.78	16.71	17.36	17.89	16.84	17.92	18.94
Metallurgical Coal	0.60	0.57	0.55	0.54	0.52	0.49	0.47	0.51	0.48	0.46
Other Coal	1.28	1.32	1.31	1.31	1.23	1.22	1.22	1.24	1.23	1.22
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.10	0.24	0.26	0.10	0.58	0.65
Net Coal Coke Imports	0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Coal Subtotal	1.91	1.90	1.87	1.86	1.86	1.97	1.96	1.86	2.30	2.35
Biofuels Heat and Coproducts	0.40	0.75	0.75	0.75	1.23	1.23	1.69	1.64	1.66	1.81
Renewable Energy[13]	2.19	2.04	2.03	2.03	2.19	2.24	2.29	2.51	2.58	2.63
Electricity	12.79	12.99	12.91	12.89	14.39	14.20	14.07	15.86	15.73	15.66
Delivered Energy	**74.01**	**72.61**	**71.74**	**71.54**	**78.81**	**75.42**	**74.25**	**85.19**	**81.26**	**79.69**
Electricity Related Losses	27.88	28.20	28.11	28.08	30.28	30.02	29.74	32.41	32.30	32.11
Total	**101.89**	**100.80**	**99.85**	**99.62**	**109.09**	**105.44**	**104.00**	**117.61**	**113.56**	**111.80**
Electric Power[14]										
Distillate Fuel Oil	0.11	0.11	0.11	0.11	0.13	0.12	0.12	0.14	0.13	0.13
Residual Fuel Oil	0.56	0.39	0.38	0.38	0.65	0.39	0.39	0.86	0.40	0.40
Liquid Fuels and Other Petroleum Subtotal	0.67	0.50	0.49	0.49	0.78	0.51	0.51	1.00	0.53	0.53
Natural Gas	7.06	6.64	6.42	6.31	6.98	6.73	6.29	7.39	7.12	6.78
Steam Coal	20.84	21.02	21.03	21.02	22.07	22.01	21.91	24.12	24.25	24.18
Nuclear Power	8.41	8.45	8.45	8.45	8.89	8.99	9.10	9.14	9.47	9.57
Renewable Energy[15]	3.45	4.37	4.42	4.49	5.78	5.79	5.79	6.41	6.43	6.46
Electricity Imports	0.11	0.08	0.08	0.09	0.04	0.06	0.09	0.09	0.10	0.12
Total[16]	**40.67**	**41.19**	**41.02**	**40.97**	**44.67**	**44.22**	**43.82**	**48.27**	**48.03**	**47.77**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Total Energy Consumption										
Liquefied Petroleum Gases	2.95	2.67	2.61	2.58	2.49	2.39	2.32	2.42	2.29	2.24
E85[8]	0.00	0.00	0.00	0.00	0.60	0.85	1.74	0.58	2.18	2.73
Motor Gasoline[2]	17.70	17.60	17.33	17.35	18.46	15.95	14.08	19.51	14.90	12.82
Jet Fuel[9]	3.23	3.04	3.00	2.98	3.51	3.42	3.33	4.23	4.12	3.96
Kerosene	0.11	0.11	0.10	0.10	0.11	0.10	0.10	0.11	0.10	0.10
Distillate Fuel Oil	9.05	8.61	8.49	8.44	9.97	9.61	9.41	11.68	11.31	11.12
Residual Fuel Oil	1.84	1.50	1.45	1.44	1.93	1.60	1.59	2.27	1.64	1.63
Petrochemical Feedstocks	1.30	1.03	1.01	1.00	1.14	1.13	1.12	1.08	1.05	1.06
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[12]	4.57	4.19	3.89	3.81	4.99	3.89	3.19	5.58	4.01	3.18
Liquid Fuels and Other Petroleum Subtotal	40.75	38.73	37.89	37.72	43.21	38.93	36.87	47.48	41.60	38.83
Natural Gas	21.86	21.41	21.29	21.19	21.77	22.07	22.01	22.13	22.86	22.93
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.00	0.00	0.49
Lease and Plant Fuel[6]	1.20	1.28	1.27	1.27	1.27	1.33	1.37	1.39	1.47	1.57
Pipeline Natural Gas	0.64	0.65	0.64	0.64	0.66	0.69	0.69	0.71	0.72	0.72
Natural Gas Subtotal	23.70	23.34	23.20	23.10	23.70	24.09	24.18	24.23	25.04	25.72
Metallurgical Coal	0.60	0.57	0.55	0.54	0.52	0.49	0.47	0.51	0.48	0.46
Other Coal	22.12	22.34	22.34	22.33	23.30	23.24	23.12	25.37	25.49	25.41
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.10	0.24	0.26	0.10	0.58	0.65
Net Coal Coke Imports	0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Coal Subtotal	22.74	22.92	22.91	22.88	23.93	23.98	23.86	25.99	26.56	26.53
Nuclear Power	8.41	8.45	8.45	8.45	8.89	8.99	9.10	9.14	9.47	9.57
Biofuels Heat and Coproducts	0.40	0.75	0.75	0.75	1.23	1.23	1.69	1.64	1.66	1.81
Renewable Energy[17]	5.65	6.40	6.45	6.52	7.97	8.03	8.08	8.92	9.01	9.09
Electricity Imports	0.11	0.08	0.08	0.09	0.04	0.06	0.09	0.09	0.10	0.12
Total	**101.89**	**100.80**	**99.85**	**99.62**	**109.09**	**105.44**	**104.00**	**117.61**	**113.56**	**111.80**
Energy Use and Related Statistics										
Delivered Energy Use	74.01	72.61	71.74	71.54	78.81	75.42	74.25	85.19	81.26	79.69
Total Energy Use	101.89	100.80	99.85	99.62	109.09	105.44	104.00	117.61	113.56	111.80
Ethanol Consumed in Motor Gasoline and E85	0.56	1.10	1.08	1.09	1.66	1.66	2.14	1.73	2.47	2.71
Population (millions)	302.41	311.37	311.37	311.37	342.61	342.61	342.61	375.12	375.12	375.12
Gross Domestic Product (billion 2000 dollars)	11524	11842	11779	11751	15486	15524	15572	20044	20114	20293
Carbon Dioxide Emissions (million metric tons)	5990.8	5865.7	5801.4	5781.7	6262.4	5982.3	5784.8	6792.3	6414.4	6202.6

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol blends (10 percent or less) in motor gasoline.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes only kerosene type.
[10]Diesel fuel for on- and off- road use.
[11]Includes aviation gasoline and lubricants.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[16]Includes non-biogenic municipal waste not included above.
[17]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2007 population and gross domestic product: IHS Global Insight Industry and Employment models, November 2008. 2007 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2007,* DOE/EIA-0573(2007) (Washington, DC, December 2008). **Projections:** EIA, AEO2009 National Energy Modeling System runs LP2009.D122308A, AEO2009.D120908A, and HP2009.D121108A.

Table C3. Energy Prices by Sector and Source
(2007 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Residential										
Liquefied Petroleum Gases	24.98	21.82	25.86	27.93	20.47	32.88	47.65	20.53	35.11	50.76
Distillate Fuel Oil	19.66	15.29	18.69	20.69	13.48	24.10	36.51	13.39	26.67	39.19
Natural Gas	12.69	11.53	12.09	12.33	11.93	12.50	12.91	13.85	14.31	14.61
Electricity	31.19	30.40	30.89	31.14	31.68	32.72	33.78	34.81	35.84	36.49
Commercial										
Liquefied Petroleum Gases	23.04	18.65	22.69	24.75	17.25	29.60	44.35	17.27	31.77	47.40
Distillate Fuel Oil	16.05	12.74	16.15	18.14	11.59	22.11	34.23	11.67	24.69	36.99
Residual Fuel Oil	10.21	7.04	10.97	12.82	5.86	16.68	27.02	5.99	17.98	29.99
Natural Gas	10.99	9.99	10.55	10.78	10.57	11.13	11.53	12.46	12.96	13.24
Electricity	28.07	26.81	27.29	27.53	26.92	28.15	29.30	29.99	31.01	31.70
Industrial[1]										
Liquefied Petroleum Gases	23.38	17.79	21.84	23.92	16.39	28.78	43.57	16.51	30.99	46.62
Distillate Fuel Oil	16.82	12.62	16.01	17.99	12.16	22.56	34.48	12.47	25.19	37.30
Residual Fuel Oil	10.49	11.72	15.38	17.26	10.68	20.94	32.04	11.10	22.73	34.48
Natural Gas[2]	7.52	6.39	6.91	7.12	7.05	7.48	7.86	8.73	9.07	9.42
Metallurgical Coal	3.61	4.34	4.37	4.39	4.32	4.40	4.49	4.29	4.41	4.49
Other Industrial Coal	2.43	2.47	2.54	2.57	2.43	2.53	2.63	2.52	2.67	2.75
Coal to Liquids	- -	- -	- -	- -	1.10	1.23	1.29	1.02	1.36	1.47
Electricity	18.63	18.36	18.72	18.90	18.45	19.06	19.70	21.05	21.59	21.76
Transportation										
Liquefied Petroleum Gases[3]	25.01	21.65	25.67	27.74	20.26	32.62	47.38	20.27	34.77	50.41
E85[4]	26.67	19.51	25.47	27.69	16.21	29.30	36.17	16.61	30.10	38.91
Motor Gasoline[5]	22.98	18.29	23.47	25.44	16.73	29.75	41.68	16.82	32.10	45.23
Jet Fuel[6]	16.10	12.60	16.03	18.12	11.05	22.15	33.99	11.03	24.63	36.94
Diesel Fuel (distillate fuel oil)[7]	20.92	16.62	20.05	22.03	15.67	26.04	37.95	15.91	28.59	40.68
Residual Fuel Oil	9.35	9.08	12.10	14.00	7.56	17.46	29.23	7.29	19.65	32.46
Natural Gas[8]	15.46	14.36	14.90	15.12	14.33	14.90	15.30	15.68	16.24	16.57
Electricity	30.64	29.96	30.34	30.53	29.27	29.48	30.56	32.61	34.15	34.98
Electric Power[9]										
Distillate Fuel Oil	14.77	11.71	15.09	17.08	9.89	20.45	32.76	9.84	23.11	35.54
Residual Fuel Oil	8.38	9.76	13.21	15.15	7.38	18.55	30.13	6.88	20.67	33.04
Natural Gas	7.02	6.09	6.59	6.79	6.69	7.15	7.47	8.22	8.70	9.01
Steam Coal	1.78	1.84	1.89	1.92	1.81	1.92	2.03	1.89	2.04	2.14
Average Price to All Users[10]										
Liquefied Petroleum Gases	18.53	17.19	20.96	22.90	16.16	27.56	41.23	16.38	29.77	44.24
E85[4]	26.67	19.51	25.47	27.69	16.21	29.30	36.17	16.61	30.10	38.91
Motor Gasoline[5]	22.82	18.29	23.47	25.44	16.73	29.75	41.68	16.82	32.10	45.23
Jet Fuel	16.10	12.60	16.03	18.12	11.05	22.15	33.99	11.03	24.63	36.94
Distillate Fuel Oil	19.94	15.58	18.98	20.96	14.85	25.28	37.24	15.17	27.94	40.07
Residual Fuel Oil	9.25	9.43	12.66	14.57	7.79	18.03	29.60	7.62	20.12	32.66
Natural Gas	9.01	8.02	8.56	8.78	8.66	9.11	9.48	10.35	10.75	11.06
Metallurgical Coal	3.61	4.34	4.37	4.39	4.32	4.40	4.49	4.29	4.41	4.49
Other Coal	1.82	1.88	1.93	1.96	1.84	1.95	2.07	1.92	2.07	2.17
Coal to Liquids	- -	- -	- -	- -	1.10	1.23	1.29	1.02	1.36	1.47
Electricity	26.70	25.94	26.42	26.65	26.54	27.57	28.56	29.64	30.56	31.12
Non-Renewable Energy Expenditures by Sector (billion 2007 dollars)										
Residential	238.38	226.46	235.27	239.70	246.77	263.30	280.47	291.88	310.03	324.47
Commercial	173.09	167.42	172.88	175.53	196.17	207.76	218.92	243.25	256.75	267.35
Industrial	226.84	183.13	204.25	215.22	180.75	242.68	314.44	203.51	276.26	349.17
Transportation	596.75	465.56	580.97	634.28	469.76	752.82	995.15	525.91	853.25	1116.08
Total Non-Renewable Expenditures	1235.06	1042.56	1193.36	1264.74	1093.46	1466.55	1808.98	1264.54	1696.29	2057.07
Transportation Renewable Expenditures	0.04	0.06	0.07	0.07	9.78	24.83	63.06	9.71	65.71	106.39
Total Expenditures	**1235.10**	**1042.62**	**1193.43**	**1264.81**	**1103.25**	**1491.38**	**1872.04**	**1274.25**	**1762.00**	**2163.46**

Table C3. Energy Prices by Sector and Source (Continued)
(Nominal Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Residential										
Liquefied Petroleum Gases	24.98	22.91	27.24	29.43	26.58	42.47	61.39	29.68	50.90	73.23
Distillate Fuel Oil	19.66	16.06	19.68	21.81	17.50	31.14	47.04	19.35	38.67	56.54
Natural Gas	12.69	12.10	12.74	12.99	15.49	16.14	16.64	20.02	20.75	21.08
Electricity	31.19	31.92	32.53	32.81	41.13	42.26	43.52	50.33	51.96	52.65
Commercial										
Liquefied Petroleum Gases	23.04	19.58	23.89	26.08	22.40	38.24	57.14	24.96	46.06	68.38
Distillate Fuel Oil	16.05	13.38	17.01	19.11	15.06	28.56	44.10	16.88	35.80	53.36
Residual Fuel Oil	10.21	7.40	11.55	13.51	7.61	21.55	34.81	8.66	26.07	43.26
Natural Gas	10.99	10.49	11.11	11.36	13.73	14.37	14.85	18.01	18.78	19.10
Electricity	28.07	28.15	28.74	29.01	34.96	36.37	37.75	43.36	44.96	45.73
Industrial[1]										
Liquefied Petroleum Gases	23.38	18.68	23.00	25.20	21.28	37.17	56.13	23.86	44.93	67.25
Distillate Fuel Oil	16.82	13.25	16.86	18.96	15.80	29.14	44.43	18.03	36.52	53.81
Residual Fuel Oil	10.49	12.30	16.20	18.19	13.87	27.05	41.29	16.05	32.95	49.74
Natural Gas[2]	7.52	6.71	7.27	7.51	9.15	9.66	10.12	12.62	13.16	13.59
Metallurgical Coal	3.61	4.56	4.60	4.62	5.61	5.69	5.78	6.20	6.40	6.48
Other Industrial Coal	2.43	2.60	2.67	2.71	3.15	3.27	3.39	3.64	3.88	3.97
Coal to Liquids	- -	- -	- -	- -	1.42	1.59	1.67	1.47	1.98	2.11
Electricity	18.63	19.28	19.72	19.92	23.97	24.63	25.38	30.43	31.30	31.39
Transportation										
Liquefied Petroleum Gases[3]	25.01	22.73	27.04	29.23	26.31	42.13	61.05	29.30	50.41	72.71
E85[4]	26.67	20.49	26.83	29.17	21.05	37.85	46.60	24.01	43.63	56.13
Motor Gasoline[5]	22.98	19.21	24.72	26.81	21.72	38.43	53.71	24.32	46.54	65.24
Jet Fuel[6]	16.10	13.23	16.89	19.09	14.35	28.62	43.79	15.94	35.70	53.29
Diesel Fuel (distillate fuel oil)[7]	20.92	17.45	21.12	23.21	20.35	33.63	48.90	23.00	41.44	58.69
Residual Fuel Oil	9.35	9.54	12.74	14.75	9.82	22.56	37.67	10.53	28.49	46.82
Natural Gas[8]	15.46	15.08	15.69	15.94	18.62	19.24	19.72	22.67	23.55	23.90
Electricity	30.64	31.46	31.95	32.18	38.01	38.09	39.37	47.14	49.51	50.47
Electric Power[9]										
Distillate Fuel Oil	14.77	12.29	15.89	18.00	12.84	26.42	42.20	14.22	33.51	51.27
Residual Fuel Oil	8.38	10.25	13.91	15.97	9.59	23.97	38.82	9.95	29.97	47.66
Natural Gas	7.02	6.39	6.94	7.15	8.69	9.24	9.63	11.88	12.61	12.99
Steam Coal	1.78	1.94	1.99	2.02	2.34	2.48	2.62	2.73	2.95	3.09

Table C3. Energy Prices by Sector and Source (Continued)
(Nominal Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Average Price to All Users[10]										
Liquefied Petroleum Gases	18.53	18.05	22.07	24.13	20.99	35.61	53.12	23.68	43.16	63.81
E85[4]	26.67	20.49	26.83	29.17	21.05	37.85	46.60	24.01	43.63	56.13
Motor Gasoline[5]	22.82	19.20	24.71	26.80	21.72	38.43	53.70	24.32	46.54	65.24
Jet Fuel	16.10	13.23	16.89	19.09	14.35	28.62	43.79	15.94	35.70	53.29
Distillate Fuel Oil	19.94	16.36	19.99	22.09	19.29	32.65	47.99	21.93	40.51	57.81
Residual Fuel Oil	9.25	9.90	13.34	15.35	10.11	23.29	38.14	11.02	29.16	47.12
Natural Gas	9.01	8.42	9.01	9.25	11.25	11.77	12.22	14.96	15.58	15.96
Metallurgical Coal	3.61	4.56	4.60	4.62	5.61	5.69	5.78	6.20	6.40	6.48
Other Coal	1.82	1.98	2.04	2.07	2.39	2.52	2.66	2.78	3.00	3.13
Coal to Liquids	- -	- -	- -	- -	1.42	1.59	1.67	1.47	1.98	2.11
Electricity	26.70	27.23	27.82	28.08	34.47	35.62	36.80	42.85	44.31	44.90
Non-Renewable Energy Expenditures by Sector (billion nominal dollars)										
Residential	238.38	237.79	247.78	252.58	320.47	340.12	361.38	421.94	449.49	468.06
Commercial	173.09	175.79	182.07	184.97	254.76	268.38	282.07	351.64	372.25	385.67
Industrial	226.84	192.29	215.12	226.79	234.72	313.49	405.15	294.19	400.54	503.70
Transportation	596.75	488.85	611.87	668.38	610.05	972.48	1282.23	760.26	1237.08	1610.01
Total Non-Renewable Expenditures	1235.06	1094.72	1256.84	1332.72	1419.99	1894.47	2330.83	1828.02	2459.36	2967.44
Transportation Renewable Expenditures	0.04	0.06	0.07	0.07	12.71	32.08	81.25	14.04	95.27	153.48
Total Expenditures	**1235.10**	**1094.78**	**1256.91**	**1332.79**	**1432.70**	**1926.55**	**2412.08**	**1842.06**	**2554.63**	**3120.92**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Excludes use for lease and plant fuel.
[3]Includes Federal and State taxes while excluding county and local taxes.
[4]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[5]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[8]Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[9]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[10]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2007 are model results and may differ slightly from official EIA data reports.

Sources: 2007 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 2007*, DOE/EIA-0487(2007) (Washington, DC, August 2008). 2007 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2007 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007) and the *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2007 transportation sector natural gas delivered prices are model results. 2007 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2007 and April 2008, Table 4.13.B. 2007 coal prices based on: EIA, *Quarterly Coal Report, October-December 2007*, DOE/EIA-0121(2007/4Q) (Washington, DC, March 2008) and EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A. 2007 electricity prices: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2007 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report.
Projections: EIA, AEO2009 National Energy Modeling System runs LP2009.D122308A, AEO2009.D120908A, and HP2009.D121108A.

Table C4. Liquid Fuels Supply and Disposition
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Crude Oil										
Domestic Crude Production[1]	5.07	5.62	5.62	5.62	5.35	6.48	7.16	5.36	7.37	8.47
Alaska	0.72	0.69	0.69	0.69	0.41	0.72	0.74	0.26	0.57	0.59
Lower 48 States	4.35	4.93	4.93	4.93	4.95	5.76	6.42	5.10	6.80	7.88
Net Imports	10.00	8.23	8.10	8.02	9.81	7.29	5.44	11.41	6.95	4.30
Gross Imports	10.03	8.26	8.13	8.05	9.84	7.33	5.47	11.44	6.99	4.35
Exports	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.03	0.04	0.05
Other Crude Supply[2]	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**15.16**	**13.85**	**13.72**	**13.64**	**15.16**	**13.77**	**12.59**	**16.77**	**14.32**	**12.77**
Other Supply										
Natural Gas Plant Liquids	1.78	1.92	1.91	1.90	1.89	1.91	1.92	1.79	1.92	1.97
Net Product Imports	2.09	1.87	1.66	1.63	2.20	1.49	1.28	2.32	1.40	1.14
Gross Refined Product Imports[3]	1.94	1.82	1.64	1.62	2.01	1.60	1.46	2.03	1.54	1.31
Unfinished Oil Imports	0.72	0.59	0.58	0.57	0.75	0.58	0.44	0.95	0.65	0.46
Blending Component Imports	0.75	0.64	0.62	0.62	0.73	0.66	0.71	0.80	0.69	0.74
Exports	1.32	1.18	1.18	1.17	1.29	1.35	1.33	1.46	1.47	1.37
Refinery Processing Gain[4]	1.00	1.01	0.97	0.98	1.02	0.93	0.88	1.06	0.86	0.72
Other Inputs	0.74	1.23	1.22	1.25	1.84	1.98	2.60	2.20	3.08	3.76
Ethanol	0.45	0.85	0.84	0.84	1.29	1.28	1.66	1.34	1.91	2.10
Domestic Production	0.43	0.85	0.84	0.84	1.23	1.24	1.56	1.35	1.43	1.48
Net Imports	0.02	-0.00	-0.00	0.00	0.06	0.04	0.10	-0.00	0.49	0.62
Biodiesel	0.03	0.06	0.06	0.07	0.06	0.10	0.13	0.07	0.13	0.17
Domestic Production	0.03	0.06	0.06	0.07	0.06	0.10	0.13	0.07	0.13	0.17
Net Imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquids from Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.38
Liquids from Coal	0.00	0.00	0.00	0.00	0.04	0.10	0.11	0.04	0.26	0.29
Liquids from Biomass	0.00	0.00	0.00	0.00	0.04	0.07	0.10	0.29	0.33	0.34
Other[5]	0.26	0.32	0.32	0.34	0.41	0.42	0.51	0.45	0.45	0.49
Total Primary Supply[6]	**20.77**	**19.88**	**19.48**	**19.41**	**22.11**	**20.08**	**19.28**	**24.13**	**21.59**	**20.36**
Liquid Fuels Consumption										
by Fuel										
Liquefied Petroleum Gases	2.09	2.04	1.99	1.97	1.90	1.82	1.77	1.84	1.74	1.71
E85[7]	0.00	0.00	0.00	0.00	0.42	0.58	1.20	0.40	1.50	1.88
Motor Gasoline[8]	9.29	9.49	9.34	9.35	9.95	8.60	7.59	10.52	8.04	6.92
Jet Fuel[9]	1.62	1.47	1.45	1.44	1.70	1.65	1.61	2.04	1.99	1.91
Distillate Fuel Oil[10]	4.20	4.14	4.08	4.06	4.79	4.62	4.52	5.61	5.42	5.33
Diesel	3.47	3.51	3.47	3.45	4.17	4.06	4.00	5.01	4.91	4.85
Residual Fuel Oil	0.72	0.65	0.63	0.63	0.84	0.70	0.69	0.99	0.72	0.71
Other[11]	2.74	2.33	2.19	2.15	2.73	2.24	1.93	2.96	2.25	1.89
by Sector										
Residential and Commercial	1.11	1.07	1.05	1.04	1.13	0.99	0.92	1.16	0.97	0.89
Industrial[12]	5.26	4.65	4.46	4.39	4.90	4.34	4.00	5.12	4.28	3.92
Transportation	14.25	14.16	13.96	13.95	15.96	14.65	14.17	17.67	16.18	15.32
Electric Power[13]	0.30	0.22	0.22	0.22	0.34	0.23	0.23	0.44	0.23	0.23
Total	**20.65**	**20.11**	**19.69**	**19.60**	**22.33**	**20.21**	**19.31**	**24.37**	**21.67**	**20.35**
Discrepancy[14]	**0.12**	**-0.23**	**-0.20**	**-0.19**	**-0.22**	**-0.13**	**-0.02**	**-0.24**	**-0.08**	**0.01**

Table C4. Liquid Fuels Supply and Disposition (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Domestic Refinery Distillation Capacity[15]	17.4	18.0	18.0	18.0	18.7	18.2	18.2	19.1	18.4	18.3
Capacity Utilization Rate (percent)[16]	89.0	78.5	77.8	77.3	82.6	77.1	70.5	89.7	79.2	71.3
Net Import Share of Product Supplied (percent)	58.3	50.8	50.1	49.8	54.6	44.0	35.4	56.9	40.9	29.8
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2007 dollars)	280.13	194.37	261.60	294.55	196.02	344.32	425.05	220.00	376.65	387.94

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes petroleum product stock withdrawals; and domestic sources of other blending components, other hydrocarbons, ethers, and renewable feedstocks for the on-site production of diesel and gasoline.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[7]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[8]Includes ethanol and ethers blended into gasoline.
[9]Includes only kerosene type.
[10]Includes distillate fuel oil and kerosene from petroleum and biomass feedstocks.
[11]Includes aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, liquid hydrogen,and miscellaneous petroleum products.
[12]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[13]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[14]Balancing item. Includes unaccounted for supply, losses, and gains.
[15]End-of-year operable capacity.
[16]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 petroleum product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). Other 2007 data: EIA, *Petroleum Supply Annual 2007,* DOE/EIA-0340(2007)/1 (Washington, DC, July 2008). **Projections:** EIA, AEO2009 National Energy Modeling System runs LP2009.D122308A, AEO2009.D120908A, and HP2009.D121108A.

Table C5. Petroleum Product Prices

(2007 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Crude Oil Prices (2007 dollars per barrel)										
Imported Low Sulfur Light Crude Oil[1]	72.33	58.61	80.16	91.08	50.43	115.45	184.60	50.23	130.43	200.42
Imported Crude Oil[1]	63.83	55.45	77.56	88.31	46.77	112.05	181.18	46.44	124.60	197.72
Delivered Sector Product Prices										
Residential										
Liquefied Petroleum Gases	213.6	186.6	221.1	238.8	175.0	281.1	407.4	175.6	300.2	434.0
Distillate Fuel Oil	272.7	212.1	259.2	287.0	186.9	334.3	506.4	185.7	369.9	543.6
Commercial										
Distillate Fuel Oil	221.7	175.8	222.8	250.2	159.8	304.9	471.9	161.0	340.4	510.0
Residual Fuel Oil	152.9	105.4	164.2	192.0	87.7	249.7	404.5	89.7	269.1	448.9
Residual Fuel Oil (2007 dollars per barrel)	64.22	44.28	68.96	80.62	36.85	104.88	169.87	37.66	113.04	188.52
Industrial[2]										
Liquefied Petroleum Gases	199.9	152.1	186.7	204.5	140.1	246.0	372.5	141.1	265.0	398.6
Distillate Fuel Oil	232.3	173.5	220.2	247.4	167.0	309.6	473.4	171.3	345.8	512.1
Residual Fuel Oil	157.1	175.4	230.2	258.4	159.9	313.4	479.6	166.2	340.2	516.2
Residual Fuel Oil (2007 dollars per barrel)	65.98	73.66	96.70	108.53	67.14	131.64	201.45	69.80	142.89	216.79
Transportation										
Liquefied Petroleum Gases	213.8	185.1	219.5	237.1	173.2	278.9	405.1	173.3	297.3	431.0
Ethanol (E85)[3]	253.0	185.1	241.7	262.7	153.8	278.0	343.2	157.6	285.5	369.1
Ethanol Wholesale Price	212.4	163.8	192.8	196.4	195.9	201.1	219.3	146.7	193.8	202.3
Motor Gasoline[4]	282.2	221.3	283.9	307.8	202.4	359.9	504.3	203.6	388.4	547.2
Jet Fuel[5]	217.3	170.1	216.5	244.6	149.2	299.1	458.8	148.9	332.4	498.7
Diesel Fuel (distillate fuel oil)[6]	287.0	227.8	274.9	302.0	214.7	356.8	520.1	218.0	391.7	557.5
Residual Fuel Oil	140.0	135.9	181.1	209.5	113.2	261.4	437.6	109.1	294.1	485.8
Residual Fuel Oil (2007 dollars per barrel)	58.80	57.09	76.07	88.01	47.54	109.80	183.79	45.81	123.54	204.05
Electric Power[7]										
Distillate Fuel Oil	204.9	162.4	209.2	236.9	137.1	283.6	454.3	136.4	320.5	492.9
Residual Fuel Oil	125.4	146.1	197.7	226.8	110.5	277.7	451.0	103.0	309.5	494.5
Residual Fuel Oil (2007 dollars per barrel)	52.67	61.35	83.03	95.25	46.43	116.64	189.44	43.27	129.98	207.70
Refined Petroleum Product Prices[8]										
Liquefied Petroleum Gases	158.5	147.0	179.2	195.8	138.2	235.7	352.5	140.1	254.5	378.2
Motor Gasoline[4]	280.2	221.3	283.9	307.8	202.4	359.9	504.3	203.5	388.4	547.2
Jet Fuel[5]	217.3	170.1	216.5	244.6	149.2	299.1	458.8	148.9	332.4	498.7
Distillate Fuel Oil	274.5	214.1	260.9	288.1	203.8	346.8	511.0	208.1	383.2	549.7
Residual Fuel Oil	138.4	141.2	189.6	218.1	116.5	269.8	443.0	114.1	301.1	488.9
Residual Fuel Oil (2007 dollars per barrel)	58.15	59.30	79.62	91.58	48.95	113.34	186.08	47.93	126.47	205.34
Average	**249.1**	**201.7**	**254.9**	**279.3**	**185.6**	**331.1**	**479.2**	**187.3**	**361.4**	**519.4**

Table C5. Petroleum Product Prices (Continued)
(Nominal Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Crude Oil Prices (nominal dollars per barrel)										
Imported Low Sulfur Light Crude Oil[1]	72.33	61.54	84.42	95.98	65.49	149.14	237.86	72.62	189.10	289.12
Imported Crude Oil[1]	63.83	58.23	81.69	93.06	60.74	144.74	233.45	67.13	180.66	285.22
Delivered Sector Product Prices										
Residential										
Liquefied Petroleum Gases	213.6	195.9	232.9	251.6	227.3	363.1	524.9	253.8	435.2	626.1
Distillate Fuel Oil	272.7	222.7	273.0	302.4	242.7	431.8	652.4	268.4	536.3	784.2
Commercial										
Distillate Fuel Oil	221.7	184.6	234.6	263.7	207.6	393.8	608.1	232.7	493.5	735.7
Residual Fuel Oil	152.9	110.7	172.9	202.3	113.9	322.6	521.1	129.6	390.2	647.5
Industrial[2]										
Liquefied Petroleum Gases	199.9	159.7	196.6	215.5	182.0	317.8	479.9	204.0	384.2	575.0
Distillate Fuel Oil	232.3	182.2	231.9	260.7	216.8	400.0	609.9	247.6	501.4	738.7
Residual Fuel Oil	157.1	184.2	242.5	272.3	207.6	404.9	618.0	240.2	493.3	744.6
Transportation										
Liquefied Petroleum Gases	213.8	194.4	231.2	249.9	224.9	360.3	522.0	250.5	431.0	621.7
Ethanol (E85)[3]	253.0	194.4	254.5	276.8	199.7	359.1	442.1	227.8	414.0	532.5
Ethanol Wholesale Price	212.4	171.9	203.1	207.0	254.4	259.8	282.5	212.1	280.9	291.8
Motor Gasoline[4]	282.2	232.4	299.0	324.3	262.8	464.9	649.8	294.3	563.1	789.4
Jet Fuel[5]	217.3	178.6	228.0	257.7	193.7	386.4	591.2	215.2	482.0	719.5
Diesel Fuel (distillate fuel oil)[6]	287.0	239.2	289.6	318.2	278.8	460.9	670.1	315.2	567.9	804.2
Residual Fuel Oil	140.0	142.7	190.8	220.8	147.0	337.7	563.8	157.7	426.5	700.8
Electric Power[7]										
Distillate Fuel Oil	204.9	170.5	220.4	249.7	178.1	366.4	585.3	197.2	464.7	711.1
Residual Fuel Oil	125.4	153.4	208.2	239.0	143.6	358.8	581.2	148.9	448.7	713.4
Refined Petroleum Product Prices[8]										
Liquefied Petroleum Gases	158.5	154.3	188.7	206.3	179.4	304.5	454.2	202.5	369.1	545.6
Motor Gasoline[4]	280.2	232.3	299.0	324.3	262.8	464.9	649.8	294.2	563.1	789.4
Jet Fuel[5]	217.3	178.6	228.0	257.7	193.7	386.4	591.2	215.2	482.0	719.5
Distillate Fuel Oil	274.5	224.8	274.7	303.5	264.7	448.0	658.4	300.9	555.7	793.0
Residual Fuel Oil (nominal dollars per barrel)	58.15	62.27	83.86	96.51	63.57	146.41	239.76	69.29	183.36	296.21
Average	**249.1**	**211.8**	**268.5**	**294.3**	**241.0**	**427.7**	**617.5**	**270.8**	**524.0**	**749.3**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]Includes only kerosene type.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 imported low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2007 imported crude oil price: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2007 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2007*, DOE/EIA-0487(2007) (Washington, DC, August 2008). 2007 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2007 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2007 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2007 wholesale ethanol prices derived from Bloomburg U.S. average rack price. **Projections:** EIA, AEO2009 National Energy Modeling System runs LP2009.D122308A, AEO2009.D120908A, and HP2009.D121108A.

Table C6. International Liquids Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Crude Oil Prices (2007 dollars per barrel)[1]										
Imported Low Sulfur Light Crude Oil Price	72.33	58.61	80.16	91.08	50.43	115.45	184.60	50.23	130.43	200.42
Imported Crude Oil Price	63.83	55.45	77.56	88.31	46.77	112.05	181.18	46.44	124.60	197.72
Crude Oil Prices (nominal dollars per barrel)[1]										
Imported Low Sulfur Light Crude Oil Price	72.33	61.54	84.42	95.98	65.49	149.14	237.86	72.62	189.10	289.12
Imported Crude Oil Price	63.83	58.23	81.69	93.06	60.74	144.74	233.45	67.13	180.66	285.22
Conventional Production (Conventional)[2]										
OPEC[3]										
Middle East	22.97	23.55	22.77	22.02	31.04	25.22	18.53	36.75	28.34	18.33
North Africa	4.02	4.35	4.25	4.07	5.57	4.61	3.44	6.64	5.19	3.45
West Africa	4.12	4.97	4.81	4.58	6.54	5.23	3.74	7.94	5.92	3.67
South America	2.58	2.32	2.26	2.16	2.94	2.42	1.79	3.54	2.73	1.78
Total OPEC	**33.68**	**35.19**	**34.09**	**32.84**	**46.10**	**37.48**	**27.50**	**54.87**	**42.18**	**27.22**
Non-OPEC										
OECD										
United States (50 states)	8.11	8.86	8.81	8.82	8.60	9.71	10.46	8.58	10.44	11.48
Canada	2.05	1.93	1.90	1.86	1.27	1.25	1.16	1.02	1.02	0.92
Mexico	3.50	2.92	2.87	2.76	2.42	2.24	2.05	2.87	2.45	2.12
OECD Europe[4]	5.23	4.36	4.27	4.12	3.31	3.18	2.84	2.96	2.94	2.44
Japan	0.13	0.14	0.14	0.14	0.18	0.16	0.13	0.20	0.18	0.14
Australia and New Zealand	0.64	0.84	0.82	0.79	0.81	0.78	0.71	0.75	0.77	0.66
Total OECD	**19.66**	**19.05**	**18.80**	**18.49**	**16.58**	**17.32**	**17.34**	**16.38**	**17.81**	**17.76**
Non-OECD										
Russia	9.88	9.72	9.50	9.10	11.46	10.24	9.08	13.17	10.50	8.63
Other Europe and Eurasia[5]	2.88	3.66	3.58	3.43	4.97	4.50	4.10	5.88	4.86	4.31
China	3.90	3.84	3.75	3.59	3.68	3.52	3.09	3.14	3.19	2.57
Other Asia[6]	3.75	3.96	3.88	3.74	3.96	3.85	3.47	3.57	3.68	3.12
Middle East	1.52	1.45	1.42	1.36	1.44	1.40	1.25	1.31	1.36	1.13
Africa	2.41	2.71	2.65	2.53	2.82	2.72	2.41	2.86	2.98	2.43
Brazil	1.88	2.54	2.48	2.38	3.88	3.45	3.05	5.30	4.19	3.42
Other Central and South America	1.79	1.74	1.70	1.64	1.61	1.56	1.40	1.99	2.05	1.71
Total Non-OECD	**28.01**	**29.62**	**28.96**	**27.78**	**33.83**	**31.25**	**27.84**	**37.22**	**32.81**	**27.33**
Total Conventional Production	**81.35**	**83.86**	**81.85**	**79.11**	**96.52**	**86.04**	**72.68**	**108.47**	**92.80**	**72.31**
Unconventional Production[7]										
United States (50 states)	0.46	0.92	0.91	0.93	1.44	1.55	2.00	1.83	2.31	2.82
Other North America	1.38	1.85	1.92	1.92	2.79	3.34	3.47	3.67	4.31	5.25
OECD Europe[3]	0.11	0.09	0.13	0.13	0.09	0.19	0.24	0.12	0.27	0.43
Middle East	0.09	0.01	0.01	0.01	0.14	0.17	0.15	0.16	0.22	0.21
Africa.	0.23	0.20	0.27	0.27	0.28	0.50	0.55	0.35	0.72	0.94
Central and South America	1.02	1.24	1.15	1.07	2.49	2.04	2.06	3.92	3.16	3.97
Other	0.30	0.34	0.47	0.47	0.39	0.78	0.99	0.75	1.63	2.95
Total Unconventional Production	**3.58**	**4.66**	**4.85**	**4.79**	**7.62**	**8.56**	**9.47**	**10.81**	**12.61**	**16.57**
Total Production	**84.93**	**88.52**	**86.71**	**83.90**	**104.14**	**94.60**	**82.15**	**119.28**	**105.41**	**88.87**

Table C6. International Liquids Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2007	2010 Low Oil Price	2010 Reference	2010 High Oil Price	2020 Low Oil Price	2020 Reference	2020 High Oil Price	2030 Low Oil Price	2030 Reference	2030 High Oil Price
Consumption[8]										
OECD										
United States (50 states)	20.65	20.11	19.69	19.60	22.33	20.21	19.31	24.37	21.67	20.35
United States Territories	0.39	0.45	0.44	0.44	0.55	0.53	0.52	0.65	0.62	0.60
Canada	2.41	2.33	2.28	2.21	2.55	2.29	2.00	2.76	2.39	2.07
Mexico	2.10	2.10	2.06	1.99	2.51	2.28	1.97	3.03	2.67	2.20
OECD Europe[3]	15.36	15.04	14.74	14.31	15.74	14.24	12.20	16.31	14.27	12.20
Japan	5.02	4.81	4.68	4.46	4.85	4.27	3.39	4.80	4.02	3.11
South Korea	2.34	2.37	2.31	2.25	2.85	2.58	2.17	3.21	2.81	2.26
Australia and New Zealand	1.08	1.06	1.04	1.01	1.20	1.09	0.96	1.36	1.20	1.06
Total OECD	**49.35**	**48.27**	**47.24**	**46.26**	**52.58**	**47.50**	**42.51**	**56.49**	**49.64**	**43.86**
Non-OECD										
Russia	2.88	3.03	2.97	2.88	3.49	3.18	2.83	3.77	3.35	2.96
Other Europe and Eurasia[5]	2.24	2.39	2.34	2.26	2.89	2.64	2.27	3.33	2.96	2.55
China	7.63	8.71	8.50	8.13	12.45	11.29	9.14	17.10	15.08	11.14
India	2.46	2.67	2.60	2.47	3.92	3.51	2.76	5.22	4.52	3.12
Other Non-OECD Asia	6.28	6.52	6.39	6.06	8.52	7.75	6.34	10.23	9.03	7.27
Middle East	6.42	7.05	7.02	6.61	8.74	8.26	7.72	10.16	9.45	8.79
Africa	3.22	3.58	3.49	3.23	4.30	3.90	3.21	4.59	4.02	3.33
Brazil	2.37	2.61	2.55	2.37	3.14	2.84	2.39	3.79	3.32	2.65
Other Central and South America	3.35	3.69	3.60	3.62	4.12	3.73	2.99	4.61	4.04	3.22
Total Non-OECD	**36.85**	**40.25**	**39.46**	**37.64**	**51.55**	**47.10**	**39.64**	**62.80**	**55.77**	**45.01**
Total Consumption	**86.20**	**88.52**	**86.70**	**83.90**	**104.14**	**94.60**	**82.15**	**119.28**	**105.41**	**88.87**
OPEC Production[9]	34.38	36.09	34.75	33.42	48.16	38.51	28.21	58.13	43.63	28.27
Non-OPEC Production[9]	50.55	52.43	51.96	50.48	55.98	56.09	53.94	61.15	61.78	60.61
Net Eurasia Exports	9.52	10.49	10.24	9.76	13.93	12.37	11.14	17.24	13.25	10.85
OPEC Market Share (percent)	40.5	40.8	40.1	39.8	46.2	40.7	34.3	48.7	41.4	31.8

[1]Weighted average price delivered to U.S. refiners.
[2]Includes production of crude oil (including lease condensate), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol and other sources, and refinery gains.
[3]OPEC = Organization of Petroleum Exporting Countries - Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[4]OECD Europe = Organization for Economic Cooperation and Development - Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.
[5]Other Europe and Eurasia = Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Serbia, Slovenia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.
[6]Other Asia = Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), Fiji, French Polynesia, Guam, Hong Kong, Indonesia, Kiribati, Laos, Malaysia, Macau, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, and Vietnam.
[7]Includes liquids produced from energy crops, natural gas, coal, extra-heavy oil, oil sands, and shale. Includes both OPEC and non-OPEC producers in the regional breakdown.
[8]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[9]Includes both conventional and unconventional liquids production.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2007 imported crude oil price: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **2007 quantities and projections:** EIA, AEO2009 National Energy Modeling System runs LP2009.D122308A, AEO2009.D120908A, and HP2009.D121108A and EIA, Generate World Oil Balance Model.

Results from Side Cases

Table D1. Key Results for Residential and Commercial Sector Technology Cases

Energy Consumption	2007	2010				2020			
		2009 Technology	Reference	High Technology	Best Available Technology	2009 Technology	Reference	High Technology	Best Available Technology
Residential									
Energy Consumption (quadrillion Btu)									
Liquefied Petroleum Gases	0.50	0.49	0.49	0.49	0.48	0.50	0.49	0.48	0.46
Kerosene	0.08	0.08	0.08	0.08	0.07	0.08	0.07	0.07	0.06
Distillate Fuel Oil	0.78	0.72	0.72	0.72	0.71	0.62	0.60	0.58	0.54
Liquid Fuels and Other Petroleum	1.35	1.29	1.29	1.28	1.27	1.20	1.16	1.13	1.06
Natural Gas	4.86	4.93	4.92	4.90	4.81	5.25	5.10	4.94	4.24
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.43	0.43	0.43	0.43	0.42	0.49	0.48	0.47	0.44
Electricity	4.75	4.81	4.80	4.78	4.35	5.26	5.12	4.82	4.04
Delivered Energy	**11.40**	**11.46**	**11.44**	**11.39**	**10.87**	**12.20**	**11.86**	**11.38**	**9.79**
Electricity Related Losses	10.36	10.46	10.44	10.40	9.48	11.11	10.81	10.19	8.53
Total	**21.76**	**21.92**	**21.88**	**21.80**	**20.34**	**23.31**	**22.67**	**21.57**	**18.32**
Delivered Energy Intensity (million Btu per household)	**100.2**	**98.6**	**98.4**	**98.0**	**93.4**	**94.0**	**91.4**	**87.7**	**75.5**
Nonmarketed Renewables Consumption (quadrillion Btu)	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.06**	**0.07**	**0.08**	**0.10**
Commercial									
Energy Consumption (quadrillion Btu)									
Liquefied Petroleum Gases	0.09	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.10
Motor Gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate Fuel Oil	0.41	0.36	0.36	0.36	0.36	0.35	0.34	0.34	0.35
Residual Fuel Oil	0.08	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08
Liquid Fuels and Other Petroleum	0.63	0.58	0.58	0.58	0.58	0.59	0.58	0.58	0.59
Natural Gas	3.10	3.15	3.14	3.12	3.11	3.38	3.34	3.27	3.20
Coal	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Renewable Energy[3]	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Electricity	4.58	4.76	4.75	4.74	4.66	5.74	5.57	5.41	4.66
Delivered Energy	**8.50**	**8.67**	**8.66**	**8.63**	**8.53**	**9.89**	**9.69**	**9.45**	**8.64**
Electricity Related Losses	9.99	10.36	10.35	10.32	10.14	12.12	11.77	11.44	9.85
Total	**18.49**	**19.04**	**19.01**	**18.95**	**18.68**	**22.01**	**21.46**	**20.89**	**18.49**
Delivered Energy Intensity (thousand Btu per square foot)	**110.0**	**106.9**	**106.7**	**106.3**	**105.2**	**107.1**	**105.0**	**102.5**	**93.7**
Commercial Sector Generation									
Net Summer Generation Capacity (megawatts)									
Natural Gas	658	697	699	699	700	1039	1244	1454	1464
Solar Photovoltaic	375	749	749	749	749	1190	1275	1434	1717
Wind	18	18	18	18	18	52	64	99	108
Electricity Generation (billion kilowatthours)									
Natural Gas	4.74	5.02	5.03	5.03	5.04	7.48	9.00	10.53	10.60
Solar Photovoltaic	0.59	1.20	1.20	1.20	1.20	1.90	2.06	2.32	2.77
Wind	0.02	0.02	0.02	0.02	0.02	0.07	0.09	0.14	0.16
Nonmarketed Renewables Consumption (quadrillion Btu)	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all feedbacks are captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.
Source: Energy Information Administration, AEO2009 National Energy Modeling System, runs BLDFRZN.D121008A, AEO2009.D120908A, BLDHIGH.D121008A, and BLDBEST.D121008A.

2030				Annual Growth 2007-2030 (percent)			
2009 Technology	Reference	High Technology	Best Available Technology	2009 Technology	Reference	High Technology	Best Available Technology
0.54	0.52	0.49	0.47	0.3%	0.2%	-0.1%	-0.3%
0.08	0.07	0.07	0.05	-0.2%	-0.5%	-0.9%	-1.9%
0.55	0.51	0.49	0.43	-1.5%	-1.8%	-2.0%	-2.5%
1.16	1.10	1.04	0.95	-0.7%	-0.9%	-1.1%	-1.5%
5.36	5.07	4.88	3.64	0.4%	0.2%	0.0%	-1.2%
0.01	0.01	0.01	0.01	-0.5%	-0.8%	-0.9%	-1.0%
0.53	0.50	0.48	0.44	0.9%	0.7%	0.5%	0.1%
6.01	5.69	5.31	4.22	1.0%	0.8%	0.5%	-0.5%
13.07	**12.36**	**11.72**	**9.26**	**0.6%**	**0.4%**	**0.1%**	**-0.9%**
12.34	11.69	10.90	8.66	0.8%	0.5%	0.2%	-0.8%
25.42	**24.05**	**22.62**	**17.92**	**0.7%**	**0.4%**	**0.2%**	**-0.8%**
92.6	**87.6**	**83.0**	**65.6**	**-0.3%**	**-0.6%**	**-0.8%**	**-1.8%**
0.06	**0.08**	**0.11**	**0.15**	**10.0%**	**11.5%**	**12.9%**	**14.5%**
0.10	0.10	0.10	0.10	0.3%	0.3%	0.3%	0.3%
0.05	0.05	0.05	0.05	0.4%	0.4%	0.4%	0.4%
0.01	0.01	0.01	0.01	1.4%	1.4%	1.4%	1.4%
0.35	0.34	0.34	0.35	-0.7%	-0.8%	-0.8%	-0.6%
0.08	0.08	0.08	0.08	0.2%	0.3%	0.2%	0.2%
0.59	0.59	0.58	0.60	-0.3%	-0.3%	-0.3%	-0.2%
3.56	3.54	3.52	3.43	0.6%	0.6%	0.6%	0.4%
0.06	0.06	0.06	0.06	-0.0%	-0.0%	-0.0%	-0.0%
0.12	0.12	0.12	0.12	0.0%	0.0%	0.0%	0.0%
6.65	6.31	5.98	4.76	1.6%	1.4%	1.2%	0.2%
10.99	**10.62**	**10.27**	**8.98**	**1.1%**	**1.0%**	**0.8%**	**0.2%**
13.66	12.96	12.28	9.79	1.4%	1.1%	0.9%	-0.1%
24.65	**23.59**	**22.56**	**18.77**	**1.3%**	**1.1%**	**0.9%**	**0.1%**
106.4	**102.9**	**99.5**	**87.0**	**-0.1%**	**-0.3%**	**-0.4%**	**-1.0%**
1991	3524	4897	5147	4.9%	7.6%	9.1%	9.4%
1547	2296	3485	5449	6.4%	8.2%	10.2%	12.3%
214	286	704	1313	11.4%	12.8%	17.3%	20.5%
14.34	25.59	35.57	37.39	4.9%	7.6%	9.2%	9.4%
2.44	3.74	5.72	8.94	6.4%	8.4%	10.4%	12.5%
0.31	0.42	1.01	1.84	11.9%	13.3%	17.7%	20.8%
0.04	**0.04**	**0.05**	**0.07**	**1.4%**	**2.0%**	**2.9%**	**4.0%**

Table D2. Key Results for Industrial Sector Technology Cases

Consumption and Indicators	2007	2010			2020			2030		
		2009 Technology	Reference	High Technology	2009 Technology	Reference	High Technology	2009 Technology	Reference	High Technology
Value of Shipments (billion 2000 dollars)										
Manufacturing	4261	3963	3963	3963	5150	5150	5150	6671	6671	6671
Nonmanufacturing	1490	1277	1277	1277	1603	1603	1603	1780	1780	1780
Total	**5750**	**5240**	**5240**	**5240**	**6753**	**6753**	**6753**	**8451**	**8451**	**8451**
Energy Consumption excluding Refining[1] (quadrillion Btu)										
Liquefied Petroleum Gases	2.34	2.01	1.98	1.96	2.04	1.77	1.55	1.95	1.66	1.42
Heat and Power	0.18	0.16	0.15	0.15	0.17	0.15	0.15	0.18	0.16	0.15
Feedstocks	2.16	1.85	1.83	1.80	1.88	1.61	1.40	1.78	1.50	1.27
Motor Gasoline	0.36	0.35	0.34	0.34	0.37	0.34	0.32	0.40	0.36	0.32
Distillate Fuel Oil	1.27	1.17	1.17	1.16	1.28	1.18	1.10	1.39	1.23	1.11
Residual Fuel Oil	0.24	0.15	0.15	0.15	0.18	0.16	0.15	0.19	0.16	0.15
Petrochemical Feedstocks	1.30	1.01	1.01	1.00	1.18	1.13	1.08	1.14	1.05	0.99
Petroleum Coke	0.36	0.27	0.27	0.26	0.33	0.29	0.26	0.38	0.31	0.27
Asphalt and Road Oil	1.19	0.98	0.96	0.95	1.26	1.08	0.93	1.38	1.12	0.92
Miscellaneous Petroleum[2]	0.62	0.31	0.30	0.30	0.27	0.21	0.19	0.30	0.21	0.19
Petroleum Subtotal	7.68	6.25	6.18	6.13	6.91	6.15	5.58	7.13	6.10	5.37
Natural Gas Heat and Power	5.14	5.08	5.02	5.01	5.69	4.86	4.79	6.17	5.11	4.97
Natural Gas Feedstocks	0.55	0.51	0.51	0.50	0.59	0.50	0.44	0.54	0.44	0.37
Lease and Plant Fuel[3]	1.20	1.27	1.27	1.27	1.33	1.33	1.33	1.47	1.47	1.47
Natural Gas Subtotal	6.89	6.87	6.80	6.79	7.61	6.69	6.56	8.17	7.02	6.81
Metallurgical Coal and Coke[4]	0.62	0.57	0.56	0.56	0.56	0.50	0.44	0.57	0.49	0.39
Other Industrial Coal	1.15	1.18	1.18	1.17	1.17	1.09	1.05	1.20	1.10	1.03
Coal Subtotal	1.77	1.75	1.74	1.73	1.72	1.60	1.49	1.76	1.59	1.42
Renewables[5]	1.64	1.48	1.48	1.48	1.61	1.64	1.69	1.88	1.96	2.08
Purchased Electricity	3.27	3.18	3.15	3.10	3.49	3.27	3.06	3.83	3.45	3.11
Delivered Energy	**21.26**	**19.53**	**19.36**	**19.24**	**21.34**	**19.35**	**18.38**	**22.77**	**20.11**	**18.79**
Electricity Related Losses	7.13	6.91	6.86	6.75	7.38	6.91	6.66	7.87	7.09	6.76
Total	**28.40**	**26.44**	**26.22**	**25.99**	**28.72**	**26.25**	**25.04**	**30.65**	**27.20**	**25.56**
Delivered Energy Use per Dollar of Shipments (thousand Btu per 2000 dollar)	**3.70**	**3.73**	**3.69**	**3.67**	**3.16**	**2.86**	**2.72**	**2.69**	**2.38**	**2.22**
Onsite Industrial Combined Heat and Power										
Capacity (gigawatts)	22.02	23.00	23.04	23.13	25.60	25.84	26.71	28.38	29.16	31.42
Generation (billion kilowatthours)	119.66	125.89	126.15	126.80	144.22	145.85	151.51	163.93	169.15	183.55

[1]Fuel consumption includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lubricants and miscellaneous petroleum products.
[3]Represents natural gas used in the field gathering and processing plant machinery.
[4]Includes net coal coke imports.
[5]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all feedbacks are captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.
Source: Energy Information Administration, AEO2009 National Energy Modeling System runs INDFRZN.D121608A, AEO2009.D120908A, and INDHIGH.D121608A.

Table D3. Key Results for Transportation Sector Technology Cases

Consumption and Indicators	2007	2010			2020			2030		
		Low Technology	Reference	High Technology	Low Technology	Reference	High Technology	Low Technology	Reference	High Technology
Level of Travel										
(billion vehicle miles traveled)										
Light-Duty Vehicles less than 8,500	2702	2747	2747	2747	3155	3161	3165	3813	3827	3837
Commercial Light Trucks[1]	72	67	67	67	85	85	85	105	105	105
Freight Trucks greater than 10,000	248	232	232	232	303	303	303	378	378	378
(billion seat miles available)										
Air	1036	951	951	951	1138	1138	1138	1410	1410	1410
(billion ton miles traveled)										
Rail	1733	1664	1664	1664	1927	1927	1927	2193	2193	2193
Domestic Shipping	662	629	629	629	744	744	744	839	839	839
Energy Efficiency Indicators										
(miles per gallon)										
Tested New Light-Duty Vehicle[2]	26.3	26.9	26.9	27.2	34.6	35.5	36.0	36.9	38.0	39.0
New Car[2]	30.3	30.6	30.7	31.4	38.1	39.1	40.2	40.4	41.4	43.2
New Light Truck[2]	23.1	23.6	23.6	23.6	30.6	30.7	30.9	32.5	33.1	33.7
Light-Duty Stock[3]	20.6	20.7	20.7	20.7	24.4	24.7	25.0	28.3	28.9	29.5
New Commercial Light Truck[1]	15.4	15.6	15.7	15.7	19.5	19.6	19.8	19.8	20.3	20.9
Stock Commercial Light Truck[1]	14.4	14.8	14.8	14.8	17.4	17.6	17.7	19.5	19.8	20.1
Freight Truck	6.0	6.0	6.0	6.0	6.3	6.5	6.8	6.5	6.9	7.2
(seat miles per gallon)										
Aircraft	62.8	64.4	64.4	64.5	67.8	68.1	68.8	72.1	73.6	75.3
(ton miles per thousand Btu)										
Rail	2.9	2.9	2.9	2.9	2.9	3.0	3.1	2.9	3.0	3.2
Domestic Shipping	2.0	2.0	2.0	2.0	2.0	2.0	2.1	2.0	2.0	2.2
Energy Use (quadrillion Btu)										
by Mode										
Light-Duty Vehicles	16.47	16.21	16.20	16.19	16.01	15.80	15.66	16.83	16.51	16.22
Commercial Light Trucks[1]	0.62	0.57	0.57	0.57	0.61	0.61	0.60	0.68	0.67	0.66
Bus Transportation	0.27	0.27	0.27	0.27	0.28	0.27	0.26	0.30	0.28	0.27
Freight Trucks	5.15	4.82	4.81	4.80	6.01	5.79	5.59	7.25	6.90	6.58
Rail, Passenger	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06
Rail, Freight	0.59	0.57	0.57	0.57	0.66	0.65	0.63	0.75	0.73	0.69
Shipping, Domestic	0.34	0.32	0.32	0.32	0.38	0.37	0.36	0.43	0.42	0.38
Shipping, International	0.88	0.80	0.80	0.80	0.90	0.90	0.89	0.91	0.91	0.90
Recreational Boats	0.25	0.25	0.25	0.25	0.26	0.26	0.26	0.28	0.28	0.28
Air	2.71	2.45	2.45	2.45	2.89	2.87	2.84	3.61	3.54	3.46
Military Use	0.70	0.74	0.74	0.74	0.74	0.74	0.74	0.78	0.78	0.78
Lubricants	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.15	0.15
Pipeline Fuel	0.64	0.64	0.64	0.64	0.69	0.69	0.69	0.72	0.72	0.72
Total	**28.82**	**27.82**	**27.81**	**27.78**	**29.63**	**29.15**	**28.72**	**32.74**	**31.94**	**31.14**
by Fuel										
Liquefied Petroleum Gases	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.01
E85[4]	0.00	0.00	0.00	0.00	0.88	0.85	0.85	2.32	2.18	2.19
Motor Gasoline[5]	17.29	16.94	16.93	16.92	15.72	15.56	15.42	14.63	14.49	14.24
Jet Fuel[6]	3.23	3.00	3.00	3.00	3.43	3.42	3.39	4.19	4.12	4.04
Distillate Fuel Oil[7]	6.48	6.14	6.13	6.12	7.63	7.36	7.11	9.54	9.09	8.64
Residual Fuel Oil	0.95	0.86	0.86	0.86	0.98	0.98	0.97	1.01	1.00	0.99
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[8]	0.17	0.17	0.17	0.17	0.18	0.18	0.18	0.18	0.18	0.18
Liquid Fuels and Other Petroleum	28.14	27.13	27.11	27.09	28.84	28.36	27.94	31.89	31.09	30.29
Pipeline Fuel Natural Gas	0.64	0.64	0.64	0.64	0.69	0.69	0.69	0.72	0.72	0.72
Compressed Natural Gas	0.02	0.03	0.03	0.03	0.07	0.07	0.06	0.09	0.09	0.08
Electricity	0.02	0.02	0.02	0.02	0.03	0.03	0.04	0.04	0.05	0.05
Delivered Energy	**28.82**	**27.82**	**27.81**	**27.78**	**29.63**	**29.15**	**28.72**	**32.74**	**31.94**	**31.14**
Electricity Related Losses	0.05	0.05	0.05	0.05	0.06	0.07	0.07	0.09	0.10	0.11
Total	**28.87**	**27.82**	**27.86**	**27.78**	**29.63**	**29.22**	**28.72**	**32.74**	**32.05**	**31.14**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]Environmental Protection Agency rated miles per gallon.
[3]Combined car and light truck "on-the-road" estimate.
[4]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[5]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[6]Includes only kerosene type.
[7]Diesel fuel for on- and off- road use.
[8]Includes aviation gasoline and lubricants.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all feedbacks are captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.
Source: Energy Information Administration, AEO2009 National Energy Modeling System runs TRNLOW.D011409A, AEO2009.D120908A, and TRNHIGH.D011409A.

Table D4. Key Results for Integrated Technology Cases

Consumption and Emissions	2007	2010			2020			2030		
		2009 Technology	Reference	High Technology	2009 Technology	Reference	High Technology	2009 Technology	Reference	High Technology
Energy Consumption by Sector (quadrillion Btu)										
Residential	11.40	11.46	11.44	11.40	12.13	11.86	11.44	12.97	12.36	11.82
Commercial	8.50	8.67	8.66	8.63	9.78	9.69	9.56	10.86	10.62	10.40
Industrial[1]	25.29	24.05	23.83	23.72	26.64	24.73	23.89	28.97	26.33	25.13
Transportation	28.82	27.83	27.81	27.78	29.59	29.15	28.76	32.61	31.94	31.23
Electric Power[2]	40.67	41.18	41.02	40.82	45.26	44.22	42.90	49.50	48.03	46.13
Total	**101.89**	**100.24**	**99.85**	**99.50**	**108.82**	**105.44**	**102.85**	**118.38**	**113.56**	**109.77**
Energy Consumption by Fuel (quadrillion Btu)										
Liquid Fuels and Other Petroleum[3]	40.75	37.97	37.89	37.82	40.14	38.93	38.06	43.36	41.60	40.13
Natural Gas	23.70	23.26	23.20	22.98	25.44	24.09	22.87	27.81	25.04	23.52
Coal	22.74	22.93	22.91	22.85	24.50	23.98	23.34	27.16	26.56	25.38
Nuclear Power	8.41	8.45	8.45	8.45	9.01	8.99	9.20	8.81	9.47	9.72
Renewable Energy[4]	6.05	7.42	7.20	7.19	9.53	9.26	9.21	10.89	10.67	10.88
Other[5]	0.23	0.21	0.21	0.21	0.22	0.19	0.17	0.36	0.22	0.14
Total	**101.89**	**100.24**	**99.85**	**99.50**	**108.82**	**105.44**	**102.85**	**118.38**	**113.56**	**109.77**
Energy Intensity (thousand Btu per 2000 dollar of GDP)	**8.84**	**8.51**	**8.48**	**8.45**	**7.03**	**6.79**	**6.61**	**5.90**	**5.65**	**5.45**
Carbon Dioxide Emissions by Sector (million metric tons)										
Residential	346	351	351	349	360	351	343	363	344	333
Commercial	216	215	214	213	225	226	224	236	236	236
Industrial[1]	987	974	965	962	1055	973	943	1145	1030	980
Transportation	2009	1888	1886	1884	1969	1937	1908	2122	2075	2021
Electric Power[6]	2433	2383	2385	2373	2550	2497	2398	2840	2729	2574
Total	**5991**	**5810**	**5801**	**5782**	**6159**	**5982**	**5817**	**6705**	**6414**	**6144**
Carbon Dioxide Emissions by Fuel (million metric tons)										
Petroleum	2580	2399	2396	2393	2485	2427	2386	2654	2564	2485
Natural Gas	1237	1221	1218	1207	1335	1265	1202	1462	1318	1238
Coal	2162	2178	2176	2171	2327	2278	2217	2577	2521	2410
Other[7]	12	12	12	12	12	12	12	12	12	12
Total	**5991**	**5810**	**5801**	**5782**	**6159**	**5982**	**5817**	**6705**	**6414**	**6144**
Carbon Dioxide Emissions (tons per person)	**19.8**	**18.7**	**18.6**	**18.6**	**18.0**	**17.5**	**17.0**	**17.9**	**17.1**	**16.4**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen.
[4]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; biogenic municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol component of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy.
[5]Includes non-biogenic municipal waste and net electricity imports.
[6]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Btu = British thermal unit.
GDP = Gross domestic product.
Note: Includes end-use, fossil electricity, and renewable technology assumptions. Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2009 National Energy Modeling System runs LTRKITEN.D011509A, AEO2009.D120908A, and HTRKITEN.D011509A.

Table D5. Key Results for Advanced Nuclear Cost Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation, Emissions, and Fuel Prices	2007	2010			2020			2030		
		High Nuclear Cost	Reference	Low Nuclear Cost	High Nuclear Cost	Reference	Low Nuclear Cost	High Nuclear Cost	Reference	Low Nuclear Cost
Capacity										
Coal Steam	311.2	321.0	321.0	321.0	327.1	327.0	327.0	364.0	352.5	338.7
Oil and Natural Gas Steam	118.8	118.4	118.4	118.4	101.3	101.8	101.8	100.6	100.5	100.3
Combined Cycle	181.0	194.8	194.8	194.8	205.2	202.7	199.9	260.0	237.7	231.6
Combustion Turbine/Diesel	133.3	142.0	142.1	142.2	155.2	155.8	155.2	198.2	201.0	204.3
Nuclear Power	100.5	101.2	101.2	101.2	105.1	108.4	113.8	74.3	112.6	132.2
Pumped Storage	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	101.5	115.5	115.6	115.5	122.7	122.3	122.4	142.3	138.8	136.9
Distributed Generation (Natural Gas)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.3	0.3
Combined Heat and Power[1]	27.8	32.5	32.6	32.5	47.3	47.3	47.3	62.8	62.6	62.3
Total	**995.6**	**1046.9**	**1047.1**	**1047.0**	**1085.3**	**1086.8**	**1088.8**	**1223.8**	**1227.4**	**1228.0**
Cumulative Additions										
Coal Steam	0.0	11.3	11.3	11.3	18.0	18.0	18.0	55.0	43.6	29.7
Oil and Natural Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	13.8	13.8	13.8	24.1	21.7	18.8	79.0	56.6	50.5
Combustion Turbine/Diesel	0.0	9.1	9.1	9.2	27.1	27.8	27.1	70.0	73.0	76.3
Nuclear Power	0.0	0.0	0.0	0.0	1.2	4.5	9.9	1.2	13.1	32.7
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	14.0	14.1	14.0	21.2	20.9	21.0	40.8	37.4	35.4
Distributed Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.3	0.3
Combined Heat and Power[1]	0.0	4.7	4.8	4.7	19.5	19.5	19.5	35.0	34.8	34.6
Total	**0.0**	**52.9**	**53.1**	**53.1**	**111.2**	**112.4**	**114.4**	**281.3**	**258.7**	**259.5**
Cumulative Retirements	**0.0**	**2.3**	**2.3**	**2.3**	**24.8**	**24.5**	**24.5**	**56.4**	**30.2**	**30.4**
Generation by Fuel (billion kilowatthours)										
Coal	2002	2038	2038	2038	2127	2125	2118	2464	2367	2252
Petroleum	61	43	43	43	45	45	44	46	46	46
Natural Gas	814	738	737	738	816	801	771	1037	880	858
Nuclear Power	806	809	809	809	840	862	903	594	907	1062
Pumped Storage	0	1	1	1	1	1	1	1	1	1
Renewable Sources	318	415	415	415	550	549	548	629	614	610
Distributed Generation	0	0	0	0	0	0	0	0	0	0
Combined Heat and Power[1]	153	174	174	175	237	237	237	338	337	336
Total	**4155**	**4217**	**4217**	**4218**	**4616**	**4618**	**4622**	**5109**	**5153**	**5163**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]										
Petroleum	66	38	38	38	40	40	39	41	41	41
Natural Gas	376	341	341	341	362	357	346	431	378	370
Coal	1980	1995	1995	1995	2090	2089	2080	2375	2299	2203
Other[3]	12	12	12	12	12	12	12	12	12	12
Total	**2433**	**2385**	**2385**	**2385**	**2503**	**2497**	**2477**	**2858**	**2729**	**2625**
Prices to the Electric Power Sector[2] (2007 dollars per million Btu)										
Petroleum	9.42	13.60	13.64	13.57	19.01	19.01	19.01	21.20	21.28	21.18
Natural Gas	7.02	6.59	6.59	6.58	7.24	7.15	7.02	9.29	8.70	8.65
Coal	1.78	1.89	1.89	1.89	1.92	1.92	1.92	2.08	2.04	2.01

[1]Includes combined heat and power plants and electricity-only plants in commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.
[3]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2009 National Energy Modeling System runs HCNUC09.D121108A, AEO2009.D120908A, and LCNUC09.D121108A.

Table D6. Key Results for Electric Power Sector Fossil Technology Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation Consumption, and Emissions	2007	2010			2020			2030		
		High Fossil Cost	Reference	Low Fossil Cost	High Fossil Cost	Reference	Low Fossil Cost	High Fossil Cost	Reference	Low Fossil Cost
Capacity										
Pulverized Coal	310.7	320.5	320.5	320.5	324.1	324.0	324.3	327.0	345.6	369.5
Coal Gasification Combined-Cycle	0.5	0.5	0.5	0.5	3.0	3.0	3.0	3.0	6.9	20.0
Conventional Natural Gas Combined-Cycle	181.0	194.8	194.8	194.8	196.3	196.4	196.6	196.6	196.5	196.9
Advanced Natural Gas Combined-Cycle	0.0	0.0	0.0	0.0	2.5	6.3	12.1	29.8	41.1	47.4
Conventional Combustion Turbine	133.3	139.6	140.6	140.9	136.5	138.5	138.8	145.6	140.9	138.9
Advanced Combustion Turbine	0.0	1.5	1.5	1.5	16.9	17.3	20.7	62.7	60.1	51.9
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	100.5	101.2	101.2	101.2	110.2	108.4	105.1	119.1	112.6	100.7
Oil and Natural Gas Steam	118.8	118.4	118.4	118.4	99.9	101.8	103.9	99.8	100.5	100.2
Renewable Sources/Pumped Storage	122.9	137.0	137.0	137.0	143.7	143.6	143.4	170.0	160.1	155.0
Distributed Generation	0.0	0.0	0.0	0.0	0.1	0.0	0.0	1.8	0.3	0.0
Combined Heat and Power[1]	27.8	32.5	32.6	32.5	47.4	47.3	47.2	62.9	62.6	61.7
Total	**995.6**	**1046.0**	**1047.1**	**1047.3**	**1080.6**	**1086.6**	**1094.9**	**1218.3**	**1227.2**	**1242.3**
Cumulative Additions										
Pulverized Coal	0.0	11.3	11.3	11.3	16.6	16.6	16.8	19.6	38.2	62.5
Coal Gasification Combined-Cycle	0.0	0.0	0.0	0.0	1.4	1.4	1.4	1.4	5.4	18.0
Conventional Natural Gas Combined-Cycle	0.0	13.8	13.8	13.8	15.3	15.4	15.6	15.5	15.5	15.9
Advanced Natural Gas Combined-Cycle	0.0	0.0	0.0	0.0	2.5	6.3	12.1	29.8	41.1	47.4
Conventional Combustion Turbine	0.0	6.6	7.6	8.0	9.0	10.5	10.1	18.0	12.9	10.2
Advanced Combustion Turbine	0.0	1.5	1.5	1.5	16.9	17.3	20.7	62.7	60.1	51.9
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	6.3	4.5	1.2	19.6	13.1	1.2
Oil and Natural Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	14.1	14.1	14.1	21.1	20.9	20.7	47.3	37.4	32.3
Distributed Generation	0.0	0.0	0.0	0.0	0.1	0.0	0.0	1.8	0.3	0.0
Combined Heat and Power[1]	0.0	4.7	4.8	4.7	19.6	19.5	19.4	35.1	34.8	33.9
Total	**0.0**	**52.0**	**53.1**	**53.4**	**108.7**	**112.4**	**117.8**	**250.9**	**258.7**	**273.3**
Cumulative Retirements	**0.0**	**2.3**	**2.3**	**2.3**	**26.8**	**24.5**	**21.6**	**31.4**	**30.2**	**29.7**
Generation by Fuel (billion kilowatthours)										
Coal	2002	2038	2038	2038	2122	2125	2129	2225	2367	2596
Petroleum	61	43	43	43	45	45	45	46	46	46
Natural Gas	814	737	737	737	786	801	822	908	880	808
Nuclear Power	806	809	809	809	875	862	840	959	907	817
Renewable Sources/Pumped Storage	319	416	415	416	551	549	549	654	615	605
Distributed Generation	0	0	0	0	0	0	0	3	0	0
Combined Heat and Power[1]	153	174	174	174	237	237	237	339	337	333
Total	**4155**	**4217**	**4217**	**4217**	**4616**	**4618**	**4622**	**5134**	**5153**	**5206**
Fuel Consumption by the Electric Power Sector (quadrillion Btu)[2]										
Coal	20.84	21.03	21.03	21.03	21.97	22.01	22.05	23.09	24.25	26.03
Petroleum	0.67	0.49	0.49	0.49	0.51	0.51	0.51	0.52	0.53	0.53
Natural Gas	7.06	6.43	6.42	6.43	6.64	6.73	6.85	7.39	7.12	6.55
Nuclear Power	8.41	8.45	8.45	8.45	9.13	8.99	8.77	10.01	9.47	8.53
Renewable Sources	3.45	4.43	4.42	4.42	5.81	5.79	5.79	6.73	6.43	6.33
Total	**40.56**	**40.95**	**40.94**	**40.94**	**44.19**	**44.16**	**44.09**	**47.86**	**47.93**	**48.10**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]										
Coal	1980	1995	1995	1994	2085	2089	2092	2190	2299	2464
Petroleum	66	38	38	38	40	40	40	40	41	41
Natural Gas	376	341	341	341	352	357	363	392	378	348
Other[3]	12	12	12	12	12	12	12	12	12	12
Total	**2433**	**2385**	**2385**	**2385**	**2488**	**2497**	**2507**	**2634**	**2729**	**2864**

[1]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.
[3]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2009 National Energy Modeling System runs HCFOSS09.D121108A, AEO2009.D120908A, and LCFOSS09.D121608A.

Table D7. Key Results for Electric Power Sector Plant Capital Cost Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation Consumption, and Emissions	2007	2020				2030			
		Falling Plant Costs	Reference	Frozen Plant Costs	High Plant Costs	Falling Plant Costs	Reference	Frozen Plant Costs	High Plant Costs
Capacity									
Pulverized Coal	310.7	324.1	324.0	324.1	324.0	348.3	345.6	335.5	324.4
Coal Gasification Combined-Cycle	0.5	3.0	3.0	3.0	3.0	13.1	6.9	6.0	3.0
Conventional Natural Gas Combined-Cycle	181.0	196.4	196.4	196.7	196.5	196.5	196.5	197.2	197.0
Advanced Natural Gas Combined-Cycle	0.0	8.9	6.3	8.4	6.4	39.8	41.1	53.6	56.0
Conventional Combustion Turbine	133.3	139.1	138.5	137.4	135.2	138.9	140.9	143.8	144.6
Advanced Combustion Turbine	0.0	20.1	17.3	14.9	14.1	60.2	60.1	59.5	63.5
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	100.5	111.4	108.4	105.1	105.1	121.6	112.6	100.7	100.7
Oil and Natural Gas Steam	118.8	103.0	101.8	99.9	99.9	99.5	100.5	99.8	99.8
Renewable Sources/Pumped Storage	122.9	143.8	143.6	143.5	143.1	174.4	160.1	155.8	151.4
Distributed Generation	0.0	0.1	0.0	0.0	0.0	1.6	0.3	0.0	0.0
Combined Heat and Power[1]	27.8	47.2	47.3	47.3	47.4	61.6	62.6	63.0	63.4
Total	**995.6**	**1097.1**	**1086.6**	**1080.4**	**1074.7**	**1255.5**	**1227.2**	**1214.9**	**1203.9**
Cumulative Additions									
Pulverized Coal	0.0	16.6	16.6	16.6	16.6	40.9	38.2	28.0	17.0
Coal Gasification Combined-Cycle	0.0	1.4	1.4	1.4	1.4	11.5	5.4	4.4	1.4
Conventional Natural Gas Combined-Cycle	0.0	15.4	15.4	15.7	15.5	15.5	15.5	16.2	16.0
Advanced Natural Gas Combined-Cycle	0.0	8.9	6.3	8.4	6.4	39.8	41.1	53.6	56.0
Conventional Combustion Turbine	0.0	10.5	10.5	9.4	8.6	11.1	12.9	15.8	18.0
Advanced Combustion Turbine	0.0	20.1	17.3	14.9	14.1	60.2	60.1	59.5	63.5
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	7.5	4.5	1.2	1.2	22.1	13.1	1.2	1.2
Oil and Natural Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	21.1	20.9	20.8	20.4	51.7	37.4	33.1	28.7
Distributed Generation	0.0	0.1	0.0	0.0	0.0	1.6	0.3	0.0	0.0
Combined Heat and Power[1]	0.0	19.4	19.5	19.5	19.6	33.8	34.8	35.2	35.6
Total	**0.0**	**121.0**	**112.4**	**107.9**	**103.8**	**288.2**	**258.7**	**247.0**	**237.5**
Cumulative Retirements	**0.0**	**22.6**	**24.5**	**26.3**	**27.8**	**31.3**	**30.2**	**30.8**	**32.4**
Generation by Fuel (billion kilowatthours)									
Coal	2002	2123	2125	2125	2125	2425	2367	2282	2168
Petroleum	61	45	45	45	45	47	46	46	46
Natural Gas	814	784	801	817	817	773	880	1021	1103
Nuclear Power	806	884	862	840	840	979	907	817	817
Renewable Sources/Pumped Storage	319	550	549	550	549	657	615	604	596
Distributed Generation	0	0	0	0	0	1	0	0	0
Combined Heat and Power[1]	153	237	237	237	237	333	337	339	341
Total	**4155**	**4623**	**4618**	**4614**	**4614**	**5214**	**5153**	**5108**	**5071**
Fuel Consumption by the Electric Power Sector (quadrillion Btu)[2]									
Coal	20.84	22.00	22.01	22.01	22.01	24.67	24.25	23.52	22.55
Petroleum	0.67	0.51	0.51	0.51	0.51	0.53	0.53	0.52	0.52
Natural Gas	7.06	6.58	6.73	6.82	6.84	6.35	7.12	8.03	8.63
Nuclear Power	8.41	9.23	8.99	8.77	8.77	10.21	9.47	8.53	8.53
Renewable Sources	3.45	5.80	5.79	5.80	5.79	6.83	6.43	6.34	6.27
Total	**40.56**	**44.24**	**44.16**	**44.04**	**44.05**	**48.72**	**47.93**	**47.07**	**46.62**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]									
Coal	1980	2087	2089	2089	2089	2338	2299	2230	2139
Petroleum	66	39	40	40	40	41	41	40	40
Natural Gas	376	349	357	362	363	337	378	426	458
Other[3]	12	12	12	12	12	12	12	12	12
Total	**2433**	**2487**	**2497**	**2502**	**2503**	**2727**	**2729**	**2709**	**2649**
Average Electricity Price (cents per kilowatthour)	**9.1**	**9.3**	**9.4**	**9.4**	**9.5**	**9.9**	**10.4**	**10.7**	**10.9**

[1]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.
[3]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2009 National Energy Modeling System runs DECCST09.D121108A, AEO2009.D120908A, FRZCST09.D121108a, and INCCST09.D121208A.

Table D8. Key Results for Greenhouse Gas Cases

Emissions, Prices, and Consumption	2007	2010			2020			2030		
		No GHG Concern	Reference	LW110	No GHG Concern	Reference	LW110	No GHG Concern	Reference	LW110
Greenhouse Gas Emissions										
(million metric tons carbon dioxide equivalent)										
Energy-related Carbon Dioxide	5990.8	5805.0	5801.4	5699.4	6044.5	5982.3	5436.0	6745.0	6414.4	4614.8
Other Covered Emissions	334.9	334.8	334.8	334.8	376.6	376.7	346.1	432.5	432.6	388.1
Total	**6325.7**	**6139.8**	**6136.2**	**6034.2**	**6421.1**	**6358.9**	**5782.2**	**7177.6**	**6847.0**	**5002.9**
Total Greenhouse Gas Emissions	7282.3	7120.4	7116.7	7014.7	7546.3	7483.9	6766.8	8501.7	8170.5	6177.9
Emissions Cap Assumed	- -	- -	- -	- -	- -	- -	4924.0	- -	- -	3860.0
Covered Emissions Net of Offsets	6368.8	6139.8	6136.2	6034.2	6421.1	6358.9	4671.8	7177.6	6847.0	3845.4
Difference (banking)	- -	- -	- -	- -	- -	- -	252.2	- -	- -	14.6
Emission Allowance Price (2007 dollars per metric ton carbon dioxide equivalent)	- -	- -	- -	- -	- -	- -	36.03	- -	- -	73.57
Energy Prices (2007 dollars per unit)										
Liquid Fuels (dollars per gallon)										
Transportation										
Motor Gasoline[1]	2.82	2.79	2.84	2.79	3.59	3.60	3.85	3.79	3.88	4.37
Jet Fuel[2]	2.17	2.11	2.16	2.11	2.97	2.99	3.30	3.24	3.32	3.95
Diesel[3]	2.87	2.69	2.75	2.69	3.54	3.57	3.87	3.80	3.92	4.53
Natural Gas (dollars per thousand cubic feet)										
Wellhead Price[4]	6.39	6.02	6.05	5.99	6.57	6.75	6.21	8.02	8.40	7.38
Residential	13.05	12.40	12.43	12.37	12.64	12.85	14.84	14.29	14.71	18.97
Electric Power[5]	7.22	6.74	6.77	6.70	7.15	7.35	9.01	8.47	8.94	12.51
Coal (dollars per million Btu)										
Minemouth[6]	1.27	1.44	1.44	1.43	1.41	1.39	1.38	1.54	1.46	1.38
Electric Power[5]	1.78	1.89	1.89	1.85	1.94	1.92	5.25	2.16	2.04	8.72
Electricity (cents per kilowatthour)	9.1	9.0	9.0	9.0	9.3	9.4	10.2	10.1	10.4	12.7
Energy Consumption										
(quadrillion Btu)										
Liquid Fuels and Other Petroleum[7]	40.75	37.93	37.89	37.91	38.97	38.93	38.35	41.66	41.60	39.87
Natural Gas	23.70	23.22	23.20	22.98	23.78	24.09	22.88	24.02	25.04	22.45
Coal[8]	22.74	22.90	22.91	21.93	24.80	23.98	20.30	30.62	26.56	16.40
Nuclear Power	8.41	8.45	8.45	8.45	8.77	8.99	9.36	8.58	9.47	12.21
Renewable/Other[9]	6.28	7.40	7.41	8.67	9.46	9.45	11.38	10.87	10.90	15.68
Total	**101.89**	**99.89**	**99.85**	**99.95**	**105.78**	**105.44**	**102.29**	**115.75**	**113.56**	**106.59**

[1]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[2]Includes only kerosene type.
[3]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[4]Represents lower 48 onshore and offshore supplies.
[5]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[6]Includes reported prices for both open market and captive mines.
[7]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen.
[8]Excludes coal converted to coal-based synthetic liquids.
[9]Includes grid-connected electricity from landfill gas; municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Includes net electricity imports.
- - = Not applicable.
GHG = Greenhouse gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2009 National Energy Modeling System runs NORSK2009.D120908A, AEO2009.D120908A, and CAP2009.D010909A.

Table D9. Key Results for Greenhouse Gas Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation Consumption, and Emissions	2007	2010			2020			2030		
		No GHG Concern	Reference	LW110	No GHG Concern	Reference	LW110	No GHG Concern	Reference	LW110
Capacity										
Pulverized Coal	310.7	320.5	320.5	320.4	333.6	324.0	301.2	380.5	345.6	216.7
Coal Gasification Combined-Cycle	0.5	0.5	0.5	0.5	3.4	3.0	14.5	17.2	6.9	100.5
Conventional Natural Gas Combined-Cycle	181.0	194.8	194.8	194.8	196.3	196.4	196.6	196.6	196.5	196.8
Advanced Natural Gas Combined-Cycle	0.0	0.0	0.0	0.0	1.8	6.3	6.4	22.2	41.1	36.9
Conventional Combustion Turbine	133.3	140.7	140.6	138.9	137.3	138.5	134.5	138.3	140.9	134.4
Advanced Combustion Turbine	0.0	1.5	1.5	1.5	17.4	17.3	4.4	55.7	60.1	13.9
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	100.5	101.2	101.2	101.2	105.1	108.4	113.0	101.4	112.6	146.3
Oil and Natural Gas Steam	118.8	118.4	118.4	118.4	102.6	101.8	94.9	100.6	100.5	91.7
Renewable Sources/Pumped Storage	122.9	136.8	137.0	145.4	143.4	143.6	154.4	156.4	160.1	225.7
Distributed Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.3	0.0
Combined Heat and Power[1]	27.8	32.5	32.6	32.4	49.1	47.3	46.6	75.4	62.6	61.9
Total	**995.6**	**1046.9**	**1047.1**	**1053.4**	**1090.0**	**1086.6**	**1066.4**	**1244.5**	**1227.2**	**1224.8**
Cumulative Additions										
Pulverized Coal	0.0	11.3	11.3	11.3	26.3	16.6	28.1	73.2	38.2	114.1
Coal Gasification Combined-Cycle	0.0	0.0	0.0	0.0	1.9	1.4	1.4	15.7	5.4	1.4
Conventional Natural Gas Combined-Cycle	0.0	13.8	13.8	13.8	15.3	15.4	17.7	15.6	15.5	33.1
Advanced Natural Gas Combined-Cycle	0.0	0.0	0.0	0.0	1.8	6.3	4.3	22.2	41.1	19.5
Conventional Combustion Turbine	0.0	7.7	7.6	5.9	9.0	10.5	5.9	10.0	12.9	6.0
Advanced Combustion Turbine	0.0	1.5	1.5	1.5	17.4	17.3	4.4	55.7	60.1	13.9
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	1.2	4.5	9.1	1.9	13.1	46.8
Oil and Natural Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	13.9	14.1	22.5	20.7	20.9	31.7	33.7	37.4	103.0
Distributed Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.3	0.0
Combined Heat and Power[1]	0.0	4.7	4.8	4.6	21.3	19.5	18.8	47.6	34.8	34.1
Total	**0.0**	**53.0**	**53.1**	**59.6**	**114.7**	**112.4**	**121.4**	**275.7**	**258.7**	**372.0**
Cumulative Retirements	**0.0**	**2.3**	**2.3**	**2.4**	**23.5**	**24.5**	**53.7**	**29.9**	**30.2**	**145.9**
Generation by Fuel (billion kilowatthours)										
Coal	2002	2037	2038	1944	2192	2125	1822	2633	2367	1600
Petroleum	61	43	43	43	45	45	42	48	46	40
Natural Gas	814	741	737	711	755	801	735	724	880	675
Nuclear Power	806	809	809	809	840	862	897	822	907	1170
Renewable Sources/Pumped Storage	319	415	415	538	551	549	715	613	615	927
Distributed Generation	0	0	0	0	0	0	0	0	0	0
Combined Heat and Power[1]	153	174	174	173	249	237	231	432	337	326
Total	**4155**	**4219**	**4217**	**4218**	**4632**	**4618**	**4442**	**5272**	**5153**	**4737**
Fuel Consumption by the Electric Power Sector (quadrillion Btu)[2]										
Coal	20.84	21.03	21.03	20.06	22.59	22.01	18.58	26.35	24.25	14.82
Petroleum	0.67	0.49	0.49	0.49	0.51	0.51	0.48	0.54	0.53	0.46
Natural Gas	7.06	6.45	6.42	6.22	6.41	6.73	6.25	6.05	7.12	5.74
Nuclear Power	8.41	8.45	8.45	8.45	8.77	8.99	9.36	8.58	9.47	12.21
Renewable Sources	3.45	4.41	4.42	5.68	5.80	5.79	7.51	6.47	6.43	10.28
Total	**40.56**	**40.95**	**40.94**	**41.02**	**44.22**	**44.16**	**42.31**	**48.11**	**47.93**	**43.63**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]										
Coal	1980	1994	1995	1903	2142	2089	1685	2494	2299	868
Petroleum	66	38	38	38	40	40	37	42	41	36
Natural Gas	376	342	341	330	340	357	325	321	378	260
Other[3]	12	12	12	12	12	12	12	12	12	13
Total	**2433**	**2386**	**2385**	**2282**	**2534**	**2497**	**2059**	**2869**	**2729**	**1176**

[1]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.
[3]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
GHG = Greenhouse gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2009 National Energy Modeling System runs NORSK2009.D120908A, AEO2009.D120908A, and CAP2009.D010909A.

Table D10. Key Results for Renewable Technology Cases

Capacity, Generation, and Emissions	2007	2010 High Renewable Cost	2010 Reference	2010 Low Renewable Cost	2020 High Renewable Cost	2020 Reference	2020 Low Renewable Cost	2030 High Renewable Cost	2030 Reference	2030 Low Renewable Cost
Net Summer Capacity (gigawatts)										
Electric Power Sector[1]										
Conventional Hydropower	76.72	76.73	76.73	76.73	77.02	77.02	77.16	77.20	77.58	78.54
Geothermal[2]	2.36	2.53	2.53	2.53	2.64	2.66	2.64	2.64	3.00	3.03
Municipal Waste[3]	3.43	3.97	4.04	4.04	4.06	4.12	4.07	4.15	4.15	4.07
Wood and Other Biomass[4]	2.18	2.20	2.20	2.20	3.97	4.22	5.58	5.00	8.86	27.00
Solar Thermal	0.53	0.54	0.54	0.54	0.81	0.81	0.81	0.86	0.86	0.86
Solar Photovoltaic	0.04	0.06	0.06	0.06	0.21	0.21	0.21	0.38	0.38	0.38
Wind	16.19	29.43	29.46	29.46	33.68	33.07	33.05	41.34	43.80	60.75
Total	**101.46**	**115.46**	**115.57**	**115.56**	**122.39**	**122.12**	**123.51**	**131.57**	**138.63**	**174.63**
End-Use Sector[5]										
Conventional Hydropower	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Waste[6]	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34
Wood and Other Biomass	4.64	4.65	4.65	4.65	7.08	7.28	7.56	12.74	13.23	14.03
Solar Photovoltaic	0.43	1.73	1.73	1.74	8.81	9.72	12.45	9.25	11.78	17.50
Wind	0.04	0.04	0.04	0.04	0.07	0.09	0.12	0.24	0.31	0.70
Total	**6.15**	**7.45**	**7.45**	**7.46**	**17.00**	**18.12**	**21.16**	**23.27**	**26.35**	**33.26**
Generation (billion kilowatthours)										
Electric Power Sector[1]										
Coal	2002	2040	2038	2035	2129	2125	2121	2374	2367	2258
Petroleum	61	43	43	43	45	45	45	47	46	46
Natural Gas	814	738	737	737	801	801	797	883	880	871
Total Fossil	**2877**	**2820**	**2818**	**2816**	**2975**	**2970**	**2963**	**3304**	**3293**	**3175**
Conventional Hydropower	245.86	268.05	268.05	268.05	296.37	296.29	296.96	297.40	298.97	303.84
Geothermal	14.84	17.78	17.78	17.78	18.91	19.11	18.91	18.94	21.80	22.06
Municipal Waste[7]	14.42	18.71	19.30	19.30	19.45	19.95	19.50	20.15	20.17	19.50
Wood and Other Biomass[4]	10.38	26.35	28.07	30.80	113.21	117.82	130.90	131.41	140.44	261.52
Dedicated Plants	8.41	12.88	12.85	12.87	25.96	28.74	39.05	34.57	62.27	193.82
Cofiring	1.97	13.47	15.22	17.93	87.25	89.08	91.85	96.85	78.17	67.70
Solar Thermal	0.60	0.99	0.99	0.99	1.88	1.88	1.88	2.02	2.02	2.02
Solar Photovoltaic	0.01	0.14	0.14	0.14	0.49	0.49	0.49	0.94	0.94	0.94
Wind	32.14	80.39	80.50	80.49	94.62	92.45	93.20	120.48	129.38	188.34
Total Renewable	**318.25**	**412.42**	**414.82**	**417.54**	**544.94**	**547.99**	**561.84**	**591.34**	**613.71**	**798.22**
End-Use Sector[5]										
Total Fossil	101	110	110	110	141	141	140	195	194	192
Conventional Hydropower[8]	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.45
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Waste[6]	2.01	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75
Wood and Other Biomass	28.13	28.19	28.20	28.22	46.00	47.17	48.82	87.93	90.81	95.83
Solar Photovoltaic	0.68	2.77	2.78	2.79	14.15	16.02	20.34	14.82	19.49	28.92
Wind	0.06	0.06	0.06	0.06	0.10	0.12	0.17	0.35	0.45	1.00
Total Renewable	**33.33**	**36.22**	**36.24**	**36.27**	**65.46**	**68.51**	**74.54**	**108.30**	**115.95**	**130.95**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[1]										
Coal	1979.7	1996.7	1995.0	1992.3	2091.9	2088.5	2083.4	2300.5	2299.0	2209.9
Petroleum	65.7	38.0	38.0	38.0	39.6	39.5	39.5	41.1	40.9	40.4
Natural Gas	376.5	341.2	340.7	341.0	357.1	356.9	355.4	378.3	377.9	375.0
Other[9]	11.6	11.6	11.6	11.6	11.7	11.7	11.7	11.7	11.7	11.7
Total	**2433.4**	**2387.5**	**2385.4**	**2382.9**	**2500.2**	**2496.6**	**2489.9**	**2731.5**	**2729.5**	**2637.1**

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes all municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[4]Includes projections for energy crops after 2010.
[5]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[6]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[7]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities.
[8]Represents own-use industrial hydroelectric power.
[9]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2009 National Energy Modeling System runs HIRENCST09.D011309B, AEO2009.D120908A, and LORENCST09.D011509B.

Table D11. Key Results for Production Tax Credit Case

Capacity, Generation, and Emissions	2007	2010		2020		2030	
		Reference	Production Tax Credit Extension	Reference	Production Tax Credit Extension	Reference	Production Tax Credit Extension
Net Summer Capacity (gigawatts)							
Electric Power Sector[1]							
Conventional Hydropower	76.72	76.73	76.73	77.02	77.03	77.58	77.47
Geothermal[2]	2.36	2.53	2.53	2.66	2.64	3.00	2.72
Municipal Waste[3]	3.43	4.04	3.81	4.12	4.09	4.15	4.14
Wood and Other Biomass[4]	2.18	2.20	2.20	4.22	4.67	8.86	9.18
Solar Thermal	0.53	0.54	0.54	0.81	0.81	0.86	0.86
Solar Photovoltaic	0.04	0.06	0.06	0.21	0.21	0.38	0.38
Wind	16.19	29.46	33.33	33.07	49.65	43.80	52.08
Total	**101.46**	**115.57**	**119.20**	**122.12**	**139.09**	**138.63**	**146.83**
End-Use Sector[5]							
Conventional Hydropower	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Waste[6]	0.34	0.34	0.34	0.34	0.34	0.34	0.34
Wood and Other Biomass	4.64	4.65	4.65	7.28	7.28	13.23	13.23
Solar Photovoltaic	0.43	1.73	1.73	9.72	9.72	11.78	11.76
Wind	0.04	0.04	0.04	0.09	0.09	0.31	0.31
Total	**6.15**	**7.45**	**7.45**	**18.12**	**18.12**	**26.35**	**26.33**
Generation (billion kilowatthours)							
Electric Power Sector[1]							
Coal	2002	2038	2039	2125	2137	2367	2360
Petroleum	61	43	43	45	45	46	46
Natural Gas	814	737	727	801	767	880	876
Total Fossil	**2877**	**2818**	**2809**	**2970**	**2948**	**3293**	**3283**
Conventional Hydropower	245.86	268.05	268.05	296.29	296.26	298.97	298.29
Geothermal	14.84	17.78	17.78	19.11	18.91	21.80	19.58
Municipal Waste[7]	14.42	19.30	17.48	19.95	19.65	20.17	20.11
Wood and Other Biomass[4]	10.38	28.07	26.51	117.82	97.83	140.44	138.81
Dedicated Plants	8.41	12.85	12.81	28.74	31.42	62.27	64.28
Cofiring	1.97	15.22	13.70	89.08	66.41	78.17	74.54
Solar Thermal	0.60	0.99	0.99	1.88	1.88	2.02	2.02
Solar Photovoltaic	0.01	0.14	0.14	0.49	0.49	0.94	0.94
Wind	32.14	80.50	93.73	92.45	149.09	129.38	157.85
Total Renewable	**318.25**	**414.82**	**424.68**	**547.99**	**584.11**	**613.71**	**637.60**
End-Use Sector[5]							
Total Fossil	101	110	110	141	141	194	193
Conventional Hydropower[8]	2.45	2.45	2.45	2.45	2.45	2.45	2.45
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Waste[6]	2.01	2.75	2.75	2.75	2.75	2.75	2.75
Wood and Other Biomass	28.13	28.20	28.20	47.17	47.18	90.81	90.86
Solar Photovoltaic	0.68	2.78	2.78	16.02	16.01	19.49	19.46
Wind	0.06	0.06	0.06	0.12	0.12	0.45	0.44
Total Renewable	**33.33**	**36.24**	**36.24**	**68.51**	**68.52**	**115.95**	**115.96**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[1]							
Coal	1979.7	1995.0	1995.4	2088.5	2098.8	2299.0	2292.5
Petroleum	65.7	38.0	38.0	39.5	39.4	40.9	40.8
Natural Gas	376.5	340.7	336.9	356.9	343.3	377.9	376.2
Other[9]	11.6	11.6	11.6	11.7	11.7	11.7	11.7
Total	**2433.4**	**2385.4**	**2381.9**	**2496.6**	**2493.2**	**2729.5**	**2721.1**

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes all municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[4]Includes projections for energy crops after 2010.
[5]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[6]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[7]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities.
[8]Represents own-use industrial hydroelectric power.
[9]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2009 National Energy Modeling System runs AEO2009.D120908A, and PTC09.D010709A.

Table D12. Natural Gas Supply and Disposition, Oil and Gas Technological Progress Cases
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2007	2010			2020			2030		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Natural Gas Prices										
(2007 dollars per million Btu)										
Henry Hub Spot Price	6.96	6.68	6.66	6.57	7.96	7.43	7.04	10.27	9.25	8.60
Average Lower 48 Wellhead Price[1]	6.22	5.90	5.88	5.81	7.03	6.56	6.22	9.07	8.17	7.59
(2007 dollars per thousand cubic feet)										
Average Lower 48 Wellhead Price[1]	6.39	6.06	6.05	5.97	7.23	6.75	6.39	9.33	8.40	7.81
Dry Gas Production[2]	**19.30**	**20.36**	**20.38**	**20.41**	**20.76**	**21.48**	**21.94**	**22.06**	**23.60**	**25.03**
Lower 48 Onshore	15.91	16.74	16.75	16.75	15.63	16.11	16.41	15.22	16.76	17.91
Associated-Dissolved	1.39	1.41	1.41	1.41	1.32	1.37	1.40	1.22	1.32	1.35
Non-Associated	14.51	15.33	15.34	15.34	14.30	14.74	15.00	14.00	15.44	16.56
Conventional	5.36	4.72	4.70	4.69	3.46	3.36	3.30	2.31	2.18	2.15
Unconventional	9.15	10.62	10.64	10.65	10.84	11.38	11.70	11.70	13.26	14.41
Gas Shale	1.17	2.26	2.31	2.31	2.54	2.97	3.05	3.36	4.15	4.48
Coalbed Methane	1.84	1.80	1.79	1.80	1.73	1.78	1.88	1.76	2.01	2.23
Tight Gas	6.15	6.56	6.54	6.54	6.57	6.62	6.78	6.57	7.10	7.70
Lower 48 Offshore	2.97	3.25	3.26	3.28	3.99	4.23	4.39	4.87	4.88	5.15
Associated-Dissolved	0.62	0.71	0.72	0.72	0.98	1.00	1.06	1.06	1.16	1.23
Non-Associated	2.35	2.53	2.55	2.56	3.01	3.23	3.34	3.81	3.72	3.92
Alaska	0.42	0.37	0.37	0.37	1.14	1.14	1.14	1.96	1.96	1.96
Supplemental Natural Gas[3]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	**3.79**	**2.51**	**2.50**	**2.49**	**2.01**	**1.86**	**1.83**	**0.91**	**0.66**	**0.84**
Pipeline[4]	3.06	2.03	2.02	2.02	0.56	0.48	0.50	-0.01	-0.18	0.03
Liquefied Natural Gas	0.73	0.48	0.47	0.47	1.46	1.38	1.33	0.92	0.85	0.80
Total Supply	**23.15**	**22.93**	**22.94**	**22.96**	**22.84**	**23.40**	**23.84**	**23.03**	**24.33**	**25.93**
Consumption by Sector										
Residential	4.72	4.78	4.79	4.79	4.92	4.96	4.99	4.86	4.93	4.97
Commercial	3.01	3.05	3.06	3.06	3.21	3.25	3.28	3.37	3.44	3.49
Industrial[5]	6.63	6.56	6.59	6.58	6.58	6.65	6.69	6.67	6.85	6.94
Electric Power[6]	6.87	6.26	6.25	6.27	6.16	6.54	6.85	6.04	6.93	8.25
Transportation[7]	0.02	0.03	0.03	0.03	0.07	0.07	0.07	0.09	0.09	0.09
Pipeline Fuel	0.62	0.62	0.62	0.62	0.66	0.67	0.68	0.67	0.70	0.73
Lease and Plant Fuel[8]	1.17	1.24	1.24	1.24	1.27	1.29	1.32	1.36	1.43	1.49
Total	**23.05**	**22.55**	**22.57**	**22.59**	**22.87**	**23.43**	**23.87**	**23.06**	**24.36**	**25.96**
Discrepancy[9]	**0.09**	**0.38**	**0.37**	**0.38**	**-0.03**	**-0.03**	**-0.03**	**-0.03**	**-0.03**	**-0.03**
Lower 48 End of Year Reserves	**225.18**	**229.03**	**230.11**	**231.42**	**200.96**	**213.14**	**222.92**	**184.54**	**211.98**	**233.91**

[1]Represents lower 48 onshore and offshore supplies.
[2]Marketed production (wet) minus extraction losses.
[3]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[4]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
[5]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[6]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[7]Compressed natural gas used as a vehicle fuel.
[8]Represents natural gas used in field gathering and processing plant machinery.
[9]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2007 values include net storage injections.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2007 consumption based on: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** EIA, AEO2009 National Energy Modeling System runs OGLTEC09.D121408A, AEO2009.D120908A, and OGHTEC09.D121408A.

Table D13. Liquid Fuels Supply and Disposition, Oil and Gas Technological Progress Cases
(Million Barrels per Day, Unless Otherwise Noted)

Supply, Disposition, and Prices	2007	2010			2020			2030		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Prices (2007 dollars per barrel)										
Imported Low Sulfur Light Crude Oil[1]	**72.33**	**78.19**	**80.16**	**78.00**	**115.61**	**115.45**	**114.58**	**132.28**	**130.43**	**129.33**
Imported Crude Oil[1]	**63.83**	**75.49**	**77.56**	**75.23**	**112.58**	**112.05**	**109.31**	**126.43**	**124.60**	**119.51**
Crude Oil Supply										
Domestic Crude Oil Production[2]	5.07	5.58	5.62	5.65	6.12	6.48	6.73	6.65	7.37	7.71
Alaska	0.72	0.69	0.69	0.69	0.71	0.72	0.72	0.57	0.57	0.58
Lower 48 Onshore	2.91	2.90	2.92	2.94	3.16	3.37	3.52	3.47	4.06	4.18
Lower 48 Offshore	1.44	1.99	2.01	2.02	2.24	2.39	2.49	2.61	2.74	2.94
Net Crude Oil Imports	10.00	8.14	8.10	8.07	7.68	7.29	7.17	7.60	6.95	6.64
Other Crude Oil Supply	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Oil Supply	**15.16**	**13.72**	**13.72**	**13.73**	**13.80**	**13.77**	**13.90**	**14.26**	**14.32**	**14.34**
Other Petroleum Supply										
Natural Gas Plant Liquids	1.78	1.91	1.91	1.91	1.86	1.91	1.94	1.82	1.92	2.03
Net Petroleum Product Imports[3]	2.09	1.68	1.66	1.67	1.52	1.49	1.42	1.40	1.40	1.37
Refinery Processing Gain[4]	1.00	0.98	0.97	0.98	0.93	0.93	0.93	0.89	0.86	0.85
Other Supply[5]	0.74	1.22	1.22	1.22	1.97	1.98	1.98	3.10	3.08	3.07
Total Primary Supply[6]	**20.77**	**19.50**	**19.48**	**19.51**	**20.07**	**20.08**	**20.16**	**21.46**	**21.59**	**21.67**
Refined Petroleum Products Supplied										
Residential and Commercial	1.11	1.05	1.05	1.05	0.99	0.99	1.00	0.97	0.97	0.98
Industrial[7]	5.26	4.47	4.46	4.47	4.34	4.34	4.37	4.29	4.28	4.31
Transportation	14.25	13.97	13.96	13.98	14.64	14.65	14.70	16.08	16.18	16.21
Electric Power[8]	0.30	0.22	0.22	0.22	0.23	0.23	0.23	0.23	0.23	0.23
Total	**20.65**	**19.71**	**19.69**	**19.71**	**20.20**	**20.21**	**20.28**	**21.57**	**21.67**	**21.73**
Discrepancy[9]	**0.12**	**-0.21**	**-0.20**	**-0.21**	**-0.13**	**-0.13**	**-0.12**	**-0.11**	**-0.08**	**-0.06**
Lower 48 End of Year Reserves (billion barrels)[2]	**18.62**	**18.96**	**19.21**	**19.41**	**21.16**	**22.50**	**23.48**	**22.70**	**25.38**	**26.45**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes lease condensate.
[3]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes ethanol (including imports), alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, biodiesel (including imports), natural gas converted to liquid fuel, coal converted to liquid fuel, and biomass converted to liquid fuel.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[7]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[8]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[9]Balancing item. Includes unaccounted for supply, losses and gains.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 product supplied data and imported crude oil price based on: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2007 imported low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2007 data: EIA, *Petroleum Supply Annual 2007,* DOE/EIA-0340(2007)/1 (Washington, DC, July 2008). **Projections:** EIA, AEO2009 National Energy Modeling System runs OGLTEC09.D121408A, AEO2009.D120908A, and OGHTEC09.D121408A.

Table D14. Natural Gas Supply and Disposition, OCS Limited Case
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2007	2010		2020		2030	
		Reference	OCS Limited	Reference	OCS Limited	Reference	OCS Limited
Natural Gas Prices							
(2007 dollars per million Btu)							
Henry Hub Spot Price	6.96	6.66	6.62	7.43	7.52	9.25	9.48
Average Lower 48 Wellhead Price[1]	6.22	5.88	5.85	6.56	6.64	8.17	8.38
(2007 dollars per thousand cubic feet)							
Average Lower 48 Wellhead Price[1]	6.39	6.05	6.01	6.75	6.83	8.40	8.61
Dry Gas Production[2]	**19.30**	**20.38**	**20.39**	**21.48**	**21.27**	**23.60**	**23.00**
Lower 48 Onshore	15.91	16.75	16.76	16.11	16.14	16.76	16.93
Associated-Dissolved	1.39	1.41	1.41	1.37	1.37	1.32	1.33
Non-Associated	14.51	15.34	15.35	14.74	14.77	15.44	15.60
Conventional	5.36	4.70	4.70	3.36	3.38	2.18	2.25
Unconventional	9.15	10.64	10.64	11.38	11.39	13.26	13.35
Gas Shale	1.17	2.31	2.31	2.97	2.97	4.15	4.22
Coalbed Methane	1.84	1.79	1.80	1.78	1.79	2.01	2.02
Tight Gas	6.15	6.54	6.54	6.62	6.63	7.10	7.11
Lower 48 Offshore	2.97	3.26	3.26	4.23	3.99	4.88	4.11
Associated-Dissolved	0.62	0.72	0.72	1.00	0.95	1.16	0.93
Non-Associated	2.35	2.55	2.55	3.23	3.04	3.72	3.18
Alaska	0.42	0.37	0.37	1.14	1.14	1.96	1.96
Supplemental Natural Gas[3]	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	**3.79**	**2.50**	**2.50**	**1.86**	**1.94**	**0.66**	**0.90**
Pipeline[4]	3.06	2.02	2.02	0.48	0.55	-0.18	0.04
Liquefied Natural Gas	0.73	0.47	0.47	1.38	1.40	0.85	0.86
Total Supply	**23.15**	**22.94**	**22.95**	**23.40**	**23.28**	**24.33**	**23.97**
Consumption by Sector							
Residential	4.72	4.79	4.79	4.96	4.95	4.93	4.91
Commercial	3.01	3.06	3.06	3.25	3.25	3.44	3.42
Industrial[5]	6.63	6.59	6.57	6.65	6.63	6.85	6.76
Electric Power[6]	6.87	6.25	6.27	6.54	6.47	6.93	6.74
Transportation[7]	0.02	0.03	0.03	0.07	0.07	0.09	0.09
Pipeline Fuel	0.62	0.62	0.62	0.67	0.67	0.70	0.71
Lease and Plant Fuel[8]	1.17	1.24	1.24	1.29	1.28	1.43	1.37
Total	**23.05**	**22.57**	**22.57**	**23.43**	**23.31**	**24.36**	**24.00**
Discrepancy[9]	**0.09**	**0.37**	**0.38**	**-0.03**	**-0.03**	**-0.03**	**-0.03**
Lower 48 End of Year Reserves	**225.18**	**230.11**	**230.00**	**213.14**	**211.41**	**211.98**	**209.17**

[1]Represents lower 48 onshore and offshore supplies.
[2]Marketed production (wet) minus extraction losses.
[3]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[4]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
[5]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[6]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[7]Compressed natural gas used as a vehicle fuel.
[8]Represents natural gas used in field gathering and processing plant machinery.
[9]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2007 values include net storage injections.
OCS = Outer continental shelf.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2007 consumption based on: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** EIA, AEO2009 National Energy Modeling System runs AEO2009.D120908A and OCSLIMITED.D120908A.

Table D15. Liquid Fuels Supply and Disposition, OCS Limited Case
(Million Barrels per Day, Unless Otherwise Noted)

Supply, Disposition, and Prices	2007	2010		2020		2030	
		Reference	OCS Limited	Reference	OCS Limited	Reference	OCS Limited
Prices (2007 dollars per barrel)							
Imported Low Sulfur Light Crude Oil[1]	**72.33**	**80.16**	**78.10**	**115.45**	**115.56**	**130.43**	**131.76**
Imported Crude Oil[1]	**63.83**	**77.56**	**75.40**	**112.05**	**112.90**	**124.60**	**126.08**
Crude Oil Supply							
Domestic Crude Oil Production[2]	5.07	5.62	5.61	6.48	6.21	7.37	6.83
Alaska	0.72	0.69	0.69	0.72	0.72	0.57	0.58
Lower 48 Onshore	2.91	2.92	2.92	3.37	3.36	4.06	4.07
Lower 48 Offshore	1.44	2.01	2.01	2.39	2.12	2.74	2.17
Net Crude Oil Imports	10.00	8.10	8.11	7.29	7.58	6.95	7.44
Other Crude Oil Supply	0.09	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Oil Supply	**15.16**	**13.72**	**13.72**	**13.77**	**13.78**	**14.32**	**14.27**
Other Petroleum Supply							
Natural Gas Plant Liquids	1.78	1.91	1.91	1.91	1.90	1.92	1.92
Net Petroleum Product Imports[3]	2.09	1.66	1.67	1.49	1.51	1.40	1.40
Refinery Processing Gain[4]	1.00	0.97	0.98	0.93	0.93	0.86	0.86
Other Supply[5]	0.74	1.22	1.22	1.98	1.97	3.08	3.07
Total Primary Supply[6]	**20.77**	**19.48**	**19.50**	**20.08**	**20.09**	**21.59**	**21.51**
Refined Petroleum Products Supplied							
Residential and Commercial	1.11	1.05	1.05	0.99	0.99	0.97	0.97
Industrial[7]	5.26	4.46	4.47	4.34	4.34	4.28	4.29
Transportation	14.25	13.96	13.97	14.65	14.66	16.18	16.10
Electric Power[8]	0.30	0.22	0.22	0.23	0.23	0.23	0.23
Total	**20.65**	**19.69**	**19.71**	**20.21**	**20.22**	**21.67**	**21.59**
Discrepancy[9]	**0.12**	**-0.20**	**-0.21**	**-0.13**	**-0.13**	**-0.08**	**-0.08**
Lower 48 End of Year Reserves (billion barrels)[2]	**18.62**	**19.21**	**19.18**	**22.50**	**21.32**	**25.38**	**23.32**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes lease condensate.
[3]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes ethanol (including imports), alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, biodiesel (including imports), natural gas converted to liquid fuel, coal converted to liquid fuel, and biomass converted to liquid fuel.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[7]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[8]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[9]Balancing item. Includes unaccounted for supply, losses and gains.
OCS = Outer continental shelf.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 product supplied data and imported crude oil price based on: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2007 imported low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2007 data: EIA, *Petroleum Supply Annual 2007,* DOE/EIA-0340(2007)/1 (Washington, DC, July 2008). **Projections:** EIA, AEO2009 National Energy Modeling System runs AEO2009.D120908A and OCSLIMITED.D120908A.

Table D16. Natural Gas Supply and Disposition, Liquefied Natural Gas Supply Cases
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2007	2010			2020			2030		
		Low LNG	Reference	High LNG	Low LNG	Reference	High LNG	Low LNG	Reference	High LNG
Dry Gas Production[1]	**19.30**	**20.46**	**20.38**	**20.39**	**21.93**	**21.48**	**19.92**	**23.84**	**23.60**	**22.00**
Lower 48 Onshore	15.91	16.81	16.75	16.76	16.46	16.11	14.92	16.93	16.76	15.35
Associated-Dissolved	1.39	1.41	1.41	1.41	1.37	1.37	1.37	1.32	1.32	1.32
Non-Associated	14.51	15.40	15.34	15.34	15.10	14.74	13.55	15.61	15.44	14.02
Conventional	5.36	4.72	4.70	4.70	3.44	3.36	3.10	2.17	2.18	2.09
Unconventional	9.15	10.67	10.64	10.64	11.66	11.38	10.45	13.43	13.26	11.94
Gas Shale	1.17	2.32	2.31	2.31	3.08	2.97	2.66	4.25	4.15	3.43
Coalbed Methane	1.84	1.80	1.79	1.79	1.81	1.78	1.67	2.02	2.01	1.92
Tight Gas	6.15	6.56	6.54	6.54	6.77	6.62	6.13	7.16	7.10	6.58
Lower 48 Offshore	2.97	3.28	3.26	3.27	4.32	4.23	3.86	4.94	4.88	4.69
Associated-Dissolved	0.62	0.72	0.72	0.72	1.02	1.00	1.00	1.17	1.16	1.03
Non-Associated	2.35	2.56	2.55	2.55	3.30	3.23	2.86	3.78	3.72	3.66
Alaska	0.42	0.37	0.37	0.37	1.14	1.14	1.14	1.96	1.96	1.96
Supplemental Natural Gas[2]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	**3.79**	**2.41**	**2.50**	**2.50**	**1.17**	**1.86**	**4.14**	**0.39**	**0.66**	**3.65**
Pipeline[3]	3.06	2.03	2.02	2.03	0.76	0.48	-0.02	-0.02	-0.18	-0.57
Liquefied Natural Gas	0.73	0.37	0.47	0.47	0.41	1.38	4.15	0.41	0.85	4.22
Total Supply	**23.15**	**22.93**	**22.94**	**22.95**	**23.16**	**23.40**	**24.13**	**24.30**	**24.33**	**25.71**
Consumption by Sector										
Residential	4.72	4.79	4.79	4.79	4.94	4.96	5.03	4.93	4.93	4.98
Commercial	3.01	3.06	3.06	3.06	3.23	3.25	3.33	3.44	3.44	3.48
Industrial[4]	6.63	6.55	6.59	6.57	6.55	6.65	6.83	6.81	6.85	7.06
Electric Power[5]	6.87	6.26	6.25	6.27	6.43	6.54	7.00	6.93	6.93	8.08
Transportation[6]	0.02	0.03	0.03	0.03	0.07	0.07	0.07	0.09	0.09	0.09
Pipeline Fuel	0.62	0.62	0.62	0.62	0.66	0.67	0.66	0.69	0.70	0.70
Lease and Plant Fuel[7]	1.17	1.24	1.24	1.24	1.32	1.29	1.23	1.44	1.43	1.35
Total	**23.05**	**22.55**	**22.57**	**22.57**	**23.19**	**23.43**	**24.16**	**24.33**	**24.36**	**25.74**
Discrepancy[8]	**0.09**	**0.38**	**0.37**	**0.38**	**-0.03**	**-0.03**	**-0.03**	**-0.03**	**-0.03**	**-0.03**
Lower 48 End of Year Reserves	**225.18**	**229.99**	**230.11**	**229.92**	**215.76**	**213.14**	**207.10**	**214.22**	**211.98**	**195.62**
Natural Gas Prices										
(2007 dollars per million Btu)										
Henry Hub Spot Price	6.96	6.64	6.66	6.62	7.65	7.43	6.44	9.18	9.25	8.84
Average Lower 48 Wellhead Price[11]	6.22	5.87	5.88	5.85	6.76	6.56	5.69	8.11	8.17	7.80
(2007 dollars per thousand cubic feet)										
Average Lower 48 Wellhead Price[11]	6.39	6.03	6.05	6.01	6.94	6.75	5.85	8.33	8.40	8.02
Delivered Prices										
(2007 dollars per thousand cubic feet)										
Residential	13.05	12.42	12.43	12.40	13.04	12.85	11.91	14.64	14.71	14.30
Commercial	11.30	10.83	10.84	10.81	11.63	11.44	10.50	13.24	13.32	12.90
Industrial[4]	7.73	7.10	7.10	7.07	7.87	7.69	6.76	9.27	9.33	8.96
Electric Power[5]	7.22	6.76	6.77	6.74	7.53	7.35	6.52	8.90	8.94	8.73
Transportation[10]	15.89	15.31	15.32	15.29	15.51	15.31	14.45	16.62	16.70	16.33
Average[11]	**9.26**	**8.79**	**8.80**	**8.76**	**9.57**	**9.37**	**8.43**	**10.99**	**11.05**	**10.61**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[6]Compressed natural gas used as vehicle fuel.
[7]Represents natural gas used in field gathering and processing plant machinery.
[8]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2007 values include net storage injections.
[9]Represents lower 48 onshore and offshore supplies.
[10]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[11]Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
LNG = Liquefied natural gas.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2007 consumption based on: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** EIA, AEO2009 National Energy Modeling System runs LOLNG09.D121408A, AEO2009.D120908A, and HILNG09.D121408A.

Table D17. Petroleum Supply and Disposition, ANWR Drilling Case
(Million Barrels per Day, Unless Otherwise Noted)

Supply, Disposition, and Prices	2007	2010		2020		2030	
		Reference	ANWR	Reference	ANWR	Reference	ANWR
Crude Oil							
Domestic Crude Production[1]	5.07	5.62	5.61	6.48	6.57	7.37	8.08
Alaska	0.72	0.69	0.69	0.72	0.83	0.57	1.30
Lower 48 States	4.35	4.93	4.93	5.76	5.74	6.80	6.78
Net Imports	10.00	8.10	8.11	7.29	7.22	6.95	6.22
Other Crude Supply[2]	0.09	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**15.16**	**13.72**	**13.72**	**13.77**	**13.80**	**14.32**	**14.31**
Other Supply							
Natural Gas Plant Liquids	1.78	1.91	1.91	1.91	1.91	1.92	1.97
Net Product Imports[3]	2.09	1.66	1.68	1.49	1.50	1.40	1.38
Refinery Processing Gain[4]	1.00	0.97	0.98	0.93	0.93	0.86	0.89
Ethanol[5]	0.45	0.84	0.84	1.28	1.28	1.91	1.91
Biodiesel[5]	0.03	0.06	0.06	0.10	0.10	0.13	0.13
Liquids from Coal	0.00	0.00	0.00	0.10	0.10	0.26	0.26
Liquids from Biomass	0.00	0.00	0.00	0.07	0.07	0.33	0.33
Other[6]	0.26	0.32	0.32	0.42	0.41	0.45	0.45
Total Primary Supply[7]	**20.77**	**19.48**	**19.50**	**20.08**	**20.12**	**21.59**	**21.62**
Refined Petroleum Products Supplied							
by Fuel							
Liquefied Petroleum Gases	2.09	1.99	2.00	1.82	1.82	1.74	1.75
E85[8]	0.00	0.00	0.00	0.58	0.58	1.50	1.50
Motor Gasoline[9]	9.29	9.34	9.35	8.60	8.61	8.04	8.01
Jet Fuel[10]	1.62	1.45	1.45	1.65	1.65	1.99	1.99
Distillate Fuel Oil[11]	4.20	4.08	4.09	4.62	4.62	5.42	5.43
Residual Fuel Oil	0.72	0.63	0.63	0.70	0.70	0.72	0.72
Other[12]	2.74	2.19	2.19	2.24	2.25	2.25	2.26
by Sector							
Residential and Commercial	1.11	1.05	1.05	0.99	1.00	0.97	0.98
Industrial[13]	5.26	4.46	4.47	4.34	4.35	4.28	4.30
Transportation	14.25	13.96	13.97	14.65	14.67	16.18	16.16
Electric Power[14]	0.30	0.22	0.22	0.23	0.23	0.23	0.23
Total	**20.65**	**19.69**	**19.71**	**20.21**	**20.24**	**21.67**	**21.66**
Discrepancy[15]	**0.12**	**-0.20**	**-0.21**	**-0.13**	**-0.12**	**-0.08**	**-0.04**
Imported Low Sulfur Light Crude Oil Price (2007 dollars per barrel)[16]	72.33	80.16	78.10	115.45	115.06	130.43	128.31
Imported Crude Oil Price (2007 dollars per barrel)[16]	63.83	77.56	75.41	112.05	111.60	124.60	121.74
Import Share of Product Supplied (percent)	58.3	50.1	50.1	44.0	43.6	40.9	37.4
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2007 dollars)	280.13	261.60	254.68	344.32	340.35	376.65	336.39

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes net imports.
[6]Includes petroleum product stock withdrawals; domestic sources of blending components, other hydrocarbons, alcohols, and ethers.
[7]Total crude supply plus all components of Other Supply.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes ethanol and ethers blended into gasoline.
[10]Includes only kerosene type.
[11]Includes distillate and kerosene.
[12]Includes aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[13]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Balancing item. Includes unaccounted for supply, losses, and gains.
[16]Weighted average price delivered to U.S. refiners.
ANWR = Arctic National Wildlife Refuge.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 imported crude oil price and petroleum product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2007 imported low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2007 data: EIA, *Petroleum Supply Annual 2007,* DOE/EIA-0340(2007)/1 (Washington, DC, July 2008). **Projections:** EIA, AEO2009 National Energy Modeling System runs AEO2009.D120908A and ANWR2009.D120908A.

Table D18. Key Results for Coal Cost Cases
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2007	2015			2030			Growth Rate, 2007-2030		
		Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost
Production[1]	**1147**	**1218**	**1206**	**1172**	**1482**	**1341**	**1076**	**1.1%**	**0.7%**	**-0.3%**
Appalachia	378	350	343	341	403	353	344	0.3%	-0.3%	-0.4%
Interior	147	185	192	211	229	252	267	1.9%	2.4%	2.6%
West	621	682	671	619	849	735	464	1.4%	0.7%	-1.3%
Waste Coal Supplied[2]	**14**	**13**	**13**	**13**	**12**	**13**	**20**	**-0.9%**	**-0.4%**	**1.5%**
Net Imports[3]	**-25**	**-36**	**-28**	**-15**	**-38**	**10**	**75**	**1.9%**	**- -**	**- -**
Total Supply[4]	**1136**	**1195**	**1192**	**1170**	**1455**	**1363**	**1171**	**1.1%**	**0.8%**	**0.1%**
Consumption by Sector										
Residential and Commercial	4	3	3	3	3	3	3	-0.4%	-0.4%	-0.4%
Coke Plants	23	20	20	20	19	18	18	-0.8%	-1.0%	-1.0%
Other Industrial[5]	57	56	56	56	56	57	55	-0.0%	-0.0%	-0.1%
Coal-to-Liquids Heat and Power	0	10	9	9	40	38	35	- -	- -	- -
Coal-to-Liquids Liquids Production	0	8	8	8	34	32	29	- -	- -	- -
Electric Power[6]	1046	1097	1096	1074	1303	1215	1030	1.0%	0.7%	-0.1%
Total Coal Use	**1129**	**1195**	**1192**	**1170**	**1455**	**1363**	**1170**	**1.1%**	**0.8%**	**0.2%**
Average Minemouth Price[7]										
(2007 dollars per short ton)	25.82	24.18	28.71	35.11	15.63	29.10	60.12	-2.2%	0.5%	3.7%
(2007 dollars per million Btu)	1.27	1.19	1.42	1.73	0.78	1.46	2.92	-2.1%	0.6%	3.7%
Delivered Prices[8]										
(2007 dollars per short ton)										
Coke Plants	94.97	101.37	115.38	129.63	76.98	115.57	196.08	-0.9%	0.9%	3.2%
Other Industrial[5]	54.42	49.65	55.54	62.83	37.90	57.22	88.60	-1.6%	0.2%	2.1%
Coal to Liquids	- -	14.57	17.14	20.87	8.94	20.96	47.60	- -	- -	- -
Electric Power[6]										
(2007 dollars per short ton)	35.45	33.56	38.47	45.12	25.52	40.61	70.73	-1.4%	0.6%	3.0%
(2007 dollars per million Btu)	1.78	1.69	1.94	2.27	1.28	2.04	3.42	-1.4%	0.6%	2.9%
Average	**37.60**	**35.21**	**40.30**	**47.09**	**25.83**	**41.30**	**72.24**	**-1.6%**	**0.4%**	**2.9%**
Exports[9]	70.25	78.99	88.70	97.22	63.79	80.02	150.83	-0.4%	0.6%	3.4%
Cumulative Electricity Generating Capacity Additions (gigawatts)[10]										
Coal	0.0	17.8	17.8	17.8	75.5	47.5	22.6	- -	- -	- -
Conventional	0.0	15.6	15.6	15.6	61.3	37.2	15.6	- -	- -	- -
Advanced without Sequestration	0.0	2.2	2.2	2.2	13.2	9.3	6.0	- -	- -	- -
Advanced with Sequestration	0.0	0.0	0.0	0.0	1.0	1.0	1.0			
Petroleum	0.0	1.3	1.3	1.3	1.4	1.4	1.4	- -	- -	- -
Natural Gas	0.0	30.5	30.4	29.9	125.3	136.9	146.2	- -	- -	- -
Nuclear	0.0	1.2	1.2	1.2	5.4	13.1	16.7	- -	- -	- -
Renewables [11]	0.0	24.0	23.5	23.9	58.0	57.6	56.5	- -	- -	- -
Other	0.0	2.3	2.2	2.3	2.3	2.3	2.3	- -	- -	- -
Total	**0.0**	**77.1**	**76.5**	**76.4**	**267.9**	**258.7**	**245.8**			
Liquids from Coal (million barrels per day)	0.00	0.06	0.06	0.06	0.26	0.26	0.26	- -	- -	- -

Table D18. Key Results for Coal Cost Cases (Continued)
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2007	2015			2030			Growth Rate, 2007-2030		
		Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost
Cost Indices										
(constant dollar index, 2007=1.000)										
Transportation Rate Multipliers										
Eastern Railroads	1.000	0.990	1.064	1.140	0.780	1.044	1.300	-1.1%	0.2%	1.1%
Western Railroads	1.000	1.010	1.082	1.160	0.890	1.183	1.480	-0.5%	0.7%	1.7%
Mine Equipment Costs										
Underground	1.000	1.008	1.071	1.136	0.867	1.071	1.319	-0.6%	0.3%	1.2%
Surface	1.000	0.948	1.007	1.069	0.815	1.007	1.241	-0.9%	0.0%	0.9%
Other Mine Supply Costs										
East of the Mississippi: All Mines	1.000	1.130	1.201	1.275	0.902	1.114	1.373	-0.4%	0.5%	1.4%
West of the Mississippi: Underground	1.000	1.130	1.201	1.275	0.902	1.114	1.373	-0.4%	0.5%	1.4%
West of the Mississippi: Surface	1.000	0.962	1.022	1.085	0.768	0.948	1.168	-1.1%	-0.2%	0.7%
Coal Mining Labor Productivity (short tons per miner per hour)	6.27	7.66	6.25	4.89	12.61	6.02	2.33	3.1%	-0.2%	-4.2%
Average Coal Miner Wage (2007 dollars per hour)	21.96	20.66	21.96	23.32	17.79	21.96	27.05	-0.9%	0.0%	0.9%

[1]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[2]Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[4]Production plus waste coal supplied plus net imports.
[5]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal use in the coal to liquids process.
[6]Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Includes reported prices for both open market and captive mines.
[8]Prices weighted by consumption tonnage; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
[9]F.a.s. price at U.S. port of exit.
[10]Cumulative additions after December 31, 2007. Includes all additions of electricity only and combined heat and power plants projected for the electric power, industrial, and commercial sectors.
[11]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 data based on: Energy Information Administration (EIA), *Annual Coal Report 2007*, DOE/EIA-0584(2007) (Washington, DC, September 2008); EIA, *Quarterly Coal Report, October-December 2007*, DOE/EIA-0121(2007/4Q) (Washington, DC, March 2008); U.S. Department of Labor, Bureau of Labor Statistics, Average Hourly Earnings of Production Workers: Coal Mining, Series ID : ceu1021210008; and EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A. **Projections:** EIA, AEO2009 National Energy Modeling System runs LCCST09.D121608A, AEO2009.D120908A, and HCCST09.D121608A.

NEMS Overview and Brief Description of Cases

The National Energy Modeling System

The projections in the *Annual Energy Outlook 2009* (*AEO2009*) are generated from the National Energy Modeling System (NEMS) [*1*], developed and maintained by the Office of Integrated Analysis and Forecasting (OIAF) of the Energy Information Administration (EIA). In addition to its use in developing the *Annual Energy Outlook* (*AEO*) projections, NEMS is also used in analytical studies for the U.S. Congress, the Executive Office of the President, other offices within the U.S. Department of Energy (DOE), and other Federal agencies. The *AEO* projections are also used by analysts and planners in other government agencies and nongovernment organizations.

The projections in NEMS are developed with the use of a market-based approach to energy analysis. For each fuel and consuming sector, NEMS balances energy supply and demand, accounting for economic competition among the various energy fuels and sources. The time horizon of NEMS is the period through 2030, approximately 25 years into the future [*2*]. In order to represent regional differences in energy markets, the component modules of NEMS function at the regional level: the nine Census divisions for the end-use demand modules; production regions specific to oil, natural gas, and coal supply and distribution; the North American Electric Reliability Council regions and subregions for electricity; and the Petroleum Administration for Defense Districts (PADDs) for refineries.

NEMS is organized and implemented as a modular system. The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. NEMS also includes macroeconomic and international modules. The primary flows of information among the modules are the delivered prices of energy to end users and the quantities consumed, by product, region, and sector. The delivered fuel prices encompass all the activities necessary to produce, import, and transport fuels to end users. The information flows also include other data on such areas as economic activity, domestic production, and international petroleum supply.

The Integrating Module controls the execution of each of the component modules. To facilitate modularity, the components do not pass information to each other directly but communicate through a central data structure. This modular design provides the capability to execute modules individually, thus allowing decentralized development of the system and independent analysis and testing of individual modules. The modular design also permits the use of the methodology and level of detail most appropriate for each energy sector. NEMS calls each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consuming sectors. A solution is reached annually through the projection horizon. Other variables, such as petroleum product imports, crude oil imports, and several macroeconomic indicators, also are evaluated for convergence.

Each NEMS component represents the impacts and costs of legislation and environmental regulations that affect that sector. NEMS accounts for all combustion-related carbon dioxide (CO_2) emissions, as well as emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury from the electricity generation sector.

The version of NEMS used for *AEO2009* represents current legislation and environmental regulations as of November 2008 (such as the Energy Independence and Security Act of 2007 [EISA2007], which was signed into law on December 19, 2007; the Energy Policy Act of 2005 [EPACT2005]; the Working Families Tax Relief Act of 2004; and the American Jobs Creation Act of 2004), and the costs of compliance with regulations (such as the new stationary diesel regulations issued by the U.S. Environmental Protection Agency [EPA] in July 2006). It does not include representation of the American Recovery and Reinvestment Act, which was enacted in February 2009. The *AEO2009* models do not represent the Clean Air Mercury Rule (CAMR), which was vacated and remanded by the D.C. Circuit Court of the U.S. Court of Appeals on February 8, 2008, but they do represent State requirements for reduction of mercury emissions.

The *AEO2009* reference case also reflects the recent decision by the D.C. Circuit Court on July 11, 2008, to vacate and remand the NO_x and SO_2 cap-and-trade programs included in the Clean Air Interstate Rule (CAIR), but not the temporary reinstatement in a more recent ruling (issued on December 23, 2008, well after the cutoff date for inclusion in *AEO2009*). It is assumed, however, that electricity generators will continue to retrofit existing capacity with emissions control equipment to comply with the revised National Ambient Air Quality Standards (NAAQS), even without the CAIR regulations. Also, it is assumed that plants not equipped with scrubbers ultimately will be required to use low-sulfur coal in order to comply with the NAAQS. The potential impacts of pending or proposed Federal and State legislation, regulations, or standards—or of sections of legislation that have been enacted but require funds or implementing regulations that have not been provided or specified—are not reflected in NEMS.

In general, the historical data used for the *AEO2009* projections are based on EIA's *Annual Energy Review 2007*, published in June 2008 [*3*]; however, data were taken from multiple sources. In some cases, only partial or preliminary data were available for 2007. CO_2 emissions were calculated by using CO_2 coefficients from the EIA report, *Emissions of Greenhouse Gases in the United States 2007*, published in December 2008 [*4*]. Historical numbers are presented for comparison only and may be estimates. Source documents should be consulted for the official data values. Footnotes to the *AEO2009* appendix tables indicate the definitions and sources of historical data.

The *AEO2009* projections for 2008 and 2009 incorporate short-term projections from EIA's November 2008 *Short-Term Energy Outlook* (*STEO*). For short-term energy projections, readers are referred to monthly updates of the *STEO* [*5*].

Component Modules

The component modules of NEMS represent the individual supply, demand, and conversion sectors of domestic energy markets and also include international and macroeconomic modules. In general, the modules interact through values representing the prices or expenditures for energy delivered to the consuming sectors and the quantities of end-use energy consumption.

Macroeconomic Activity Module

The Macroeconomic Activity Module (MAM) provides a set of macroeconomic drivers to the energy modules, and there is a macroeconomic feedback mechanism within NEMS. Key macroeconomic variables used in the energy modules include gross domestic product (GDP), disposable income, value of industrial shipments, new housing starts, sales of new light-duty vehicles (LDVs), interest rates, and employment. The MAM uses the following models from IHS Global Insight: Macroeconomic Model of the U.S. Economy, National Industry Model, and National Employment Model. In addition, EIA has constructed a Regional Economic and Industry Model to project regional economic drivers, and a Commercial Floorspace Model to project 13 floorspace types in 9 Census divisions. The accounting framework for industrial value of shipments uses the North American Industry Classification System (NAICS).

International Module

The International Module represents the response of world oil markets (supply and demand) to assumed world oil prices. The results/outputs of the module are international liquids consumption and production by region and a crude oil supply curve representing international crude oil similar in quality to the West Texas Intermediate crude that is available to U.S. markets through the Petroleum Market Module (PMM) of NEMS. The supply-curve calculations are based on historical market data and a world oil supply/demand balance, which is developed from reduced-form models of international liquids supply and demand, current investment trends in exploration and development, and long-term resource economics for 221 countries/territories. The oil production estimates include both conventional and unconventional supply recovery technologies.

Residential and Commercial Demand Modules

The Residential Demand Module projects energy consumption in the residential sector by housing type and end use, based on delivered energy prices, the menu of equipment available, the availability of renewable sources of energy, and housing starts. The Commercial Demand Module projects energy consumption in the commercial sector by building type and nonbuilding uses of energy and by category of end use, based on delivered prices of energy, availability of renewable sources of energy, and macroeconomic variables representing interest rates and floorspace construction.

Both modules estimate the equipment stock for the major end-use services, incorporating assessments of advanced technologies, including representations of renewable energy technologies; and the effects of both building shell and appliance standards, including the recently enacted provisions of the Energy Independence and Security Act of 2007 (EISA2007). The Commercial Demand Module incorporates combined heat and power (CHP) technology. The modules also include projections of distributed generation. Both modules incorporate changes to "normal" heating and cooling degree-days by Census division, based on a 10-year average and on State-level population projections. The Residential Demand Module projects an increase in the average square footage of both new construction and existing structures, based on trends in the size of new construction and the remodeling of existing homes.

Industrial Demand Module

The Industrial Demand Module projects the consumption of energy for heat and power and for feedstocks and raw materials in each of 21 industries, subject to the delivered prices of energy and macroeconomic variables representing employment and the value of shipments for each industry. As noted in the description of the MAM, the value of shipments is based on NAICS. The industries are classified into three groups—energy-intensive manufacturing, non-energy-intensive manufacturing, and nonmanufacturing. Of the eight energy-intensive industries, seven are modeled in the Industrial Demand Module, with components for boiler/steam/cogeneration, buildings, and process/assembly use of energy. Bulk chemicals are further disaggregated to organic, inorganic, resins, and agricultural chemicals. A generalized representation of cogeneration and a recycling component also are included. The use of energy for petroleum refining is modeled in the PMM, and the projected consumption is included in the industrial totals.

Transportation Demand Module

The Transportation Demand Module projects consumption of fuels in the transportation sector, including petroleum products, electricity, methanol, ethanol, compressed natural gas, and hydrogen, by transportation mode, vehicle vintage, and size class, subject to delivered prices of energy fuels and macroeconomic variables representing disposable personal income, GDP, population, interest rates, and industrial shipments. Fleet vehicles are represented separately to allow analysis of the Energy Policy Act of 1992 (EPACT1992) and other legislation and legislative proposals. The transportation demand module also includes a component to assess the penetration of alternative-fuel vehicles (AFVs). EPACT2005 and the Energy Improvement and Extension Act of 2008 (EIEA2008) are reflected in the assessment of the impacts of tax credits on the purchase of hybrid gas-electric, alternative-fuel, and fuel-cell vehicles. The corporate average fuel economy (CAFE) and biofuel representation in the module reflect standards proposed by the National Highway Traffic Safety Administration (NHTSA) and provisions in EISA2007.

The air transportation component of the Transportation Demand Module explicitly represents air travel in domestic and foreign markets and includes the industry practice of parking aircraft in both domestic and international markets to reduce operating costs, as well as the movement of aging aircraft from passenger to cargo markets [*6*]. For passenger travel and air freight shipments, the module represents regional fuel use in regional, narrow-body, and wide-body aircraft. An infrastructure constraint, which is also modeled, can potentially limit overall growth in passenger and freight air travel to levels commensurate with industry-projected infrastructure expansion and capacity growth.

Electricity Market Module

The Electricity Market Module represents generation, transmission, and pricing of electricity, subject to delivered prices for coal, petroleum products, natural gas, and biofuels; costs of generation by all generating plants, including capital costs and macroeconomic variables for costs of capital and domestic investment; environmental emissions laws and regulations; and electricity load shapes and demand. There are three primary submodules—capacity planning, fuel dispatching, and finance and pricing.

All specifically identified options promulgated by the EPA for compliance with the Clean Air Act Amendments of 1990 (CAAA90) are explicitly represented in the capacity expansion and dispatch decisions; those that have not been promulgated (e.g., fine particulate proposals) are not incorporated. All financial incentives for power generation expansion and dispatch specifically identified in EPACT2005 have been implemented. Several States, primarily in the Northeast, have recently enacted air emission regulations for CO_2 that affect the electricity generation sector, and those regulations are represented in *AEO2009*.

Although currently there is no Federal legislation in place that restricts greenhouse gas (GHG) emissions, regulators and the investment community are beginning to push energy companies to invest in technologies that are less GHG-intensive. The trend is captured in the *AEO2009* reference case through a 3-percentage-point increase in the cost of capital when investments in new coal-fired power plants without carbon control and sequestration (CCS) and new coal-to-liquids (CTL) plants are evaluated.

Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules representing renewable resource supply and technology input information for central-station, grid-connected electricity generation technologies, including conventional hydroelectricity, biomass (Dedicated biomass plants and co-firing in existing coal plants), geothermal, landfill gas, solar thermal electricity, solar photovoltaics (PV), and wind energy. The RFM contains renewable resource supply estimates representing the regional opportunities for renewable energy development. Investment tax credits (ITCs) for renewable fuels are incorporated, as currently enacted, including a permanent 10-percent ITC for business investment in solar energy (thermal nonpower uses as well as power uses) and geothermal power (available only to those projects not accepting the production tax credit [PTC] for geothermal power). In addition, the module reflects the increase in the ITC to 30 percent for solar energy systems installed before January 1, 2017, and the extension of the credit to individual homeowners under EIEA2008.

PTCs for wind, geothermal, landfill gas, and some types of hydroelectric and biomass-fueled plants also are represented. They provide a credit of up to 2.0 cents per kilowatthour for electricity produced in the first 10 years of plant operation. For *AEO2009*, new plants coming on line before January 1, 2010, are eligible to receive the ITC. *AEO2009* also accounts for new renewable energy capacity resulting from State renewable portfolio standard (RPS) programs, mandates, and goals, as described in *Assumptions to the Annual Energy Outlook 2009* [7].

Oil and Gas Supply Module

The Oil and Gas Supply Module represents domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships among the various sources of supply: onshore, offshore, and Alaska by both conventional and unconventional techniques, including natural gas recovery from coalbeds and low-permeability formations of sandstone and shale. The framework analyzes cash flow and profitability to compute investment and drilling for each of the supply sources, based on the prices for crude oil and natural gas, the domestic recoverable resource base, and the state of technology. Oil and natural gas production activities are modeled for 12 supply regions, including 3 offshore and 3 Alaskan regions.

Crude oil production quantities are used as inputs to the PMM in NEMS for conversion and blending into refined petroleum products. Supply curves for natural gas are used as inputs to the Natural Gas Transmission and Distribution Module for determining natural gas prices and quantities.

Natural Gas Transmission and Distribution Module

The Natural Gas Transmission and Distribution Module represents the transmission, distribution, and pricing of natural gas, subject to end-use demand for natural gas and the availability of domestic natural gas and natural gas traded on the international market. The module tracks the flows of natural gas and determines the associated capacity expansion requirements in an aggregate pipeline network, connecting the domestic and foreign supply regions with 12 U.S. demand regions. The flow of natural gas is determined for both a peak and off-peak period in the year. Key components of pipeline and distributor tariffs are included in separate pricing algorithms. The module also represents foreign sources of natural gas, including pipeline imports and exports to Canada and Mexico, and LNG imports and exports.

Petroleum Market Module

The PMM projects prices of petroleum products, crude oil and product import activity, and domestic refinery operations (including fuel consumption), subject to the demand for petroleum products, the availability and price of imported petroleum, and the domestic production of crude oil, natural gas liquids, and biofuels (ethanol, biodiesel, and biomass-to-liquids [BTL]). The module represents refining activities in the five PADDs, as well as a less detailed representation of refining activities in the rest of the world. It explicitly models the requirements of EISA2007 and CAAA90 and the costs of automotive fuels, such as conventional and reformulated gasoline, and includes the production of biofuels for blending in gasoline and diesel.

AEO2009 represents regulations that limit the sulfur content of all nonroad and locomotive/marine diesel to 15 parts per million (ppm) by mid-2012. The module also reflects the new renewable fuels standard (RFS) in EISA2007 that requires the use of 36 billion gallons per year of biofuels by 2022 if achievable, with corn ethanol limited to 15 billion gallons per year. Demand growth and regulatory changes necessitate capacity expansion for refinery processing units. U.S. end-use prices are based on the marginal costs of production, plus markups representing the costs of product marketing, importing, transportation, and distribution, as well as applicable State and Federal taxes [*8*]. Refinery capacity expansion at existing sites is permitted in each of the five refining regions modeled.

Fuel ethanol and biodiesel are included in the PMM, because they are commonly blended into petroleum products. The module allows ethanol blending into gasoline at 10 percent or less by volume (E10) and up to 85 percent by volume (E85). For *AEO2009*, the level of allowable non-E85 ethanol blending in California has been raised from 5.7 percent to 10 percent in recent regulatory changes [*9*] that have set a framework for E10 emissions standards.

Ethanol is produced primarily in the Midwest from corn or other starchy crops, and in the future it may be produced from cellulosic material, such as switchgrass and poplar. Biodiesel (diesel-like fuel made in a trans-esterification process) is produced from seed oil, imported palm oil, animal fats, or yellow grease (primarily, recycled cooking oil). Renewable or "green" diesel is also modeled as a blending component in petroleum diesel. Unlike the more common biodiesel, renewable diesel is made by hydrogenation of vegetable oils and is completely fungible with petroleum diesel. Imports and limited exports of these biofuels are modeled in the PMM.

Both domestic and imported ethanol count toward the RFS. Domestic ethanol production from two feedstocks, corn and cellulosic materials, is modeled. Corn-based ethanol plants are numerous (more than 150 are now in operation, with a total production capacity of more than 10 billion gallons annually) and are based on a well-known technology that converts sugar into ethanol. Ethanol from cellulosic sources is a new technology with no pilot plants in operation; however, DOE awarded grants (up to $385 million) in 2007 to construct capacity totaling 147 million gallons per year, which *AEO2009* assumes will begin operating in 2012. Imported ethanol may be produced from cane sugar or bagasse, the cellulosic byproduct of sugar milling. The sources of ethanol are modeled to compete on an economic basis and to meet the EISA2007 renewable fuels mandate.

Fuels produced by gasification and Fischer-Tropsch synthesis are also modeled in the PMM, based on their economics relative to competing feedstocks and products. The three processes modeled are coal-to-liquids (CTL), gas-to-liquids (GTL), and BTL. CTL facilities are likely to be built at locations close to coal supplies and water sources, where liquid products and surplus electricity could also be distributed to nearby demand regions. GTL facilities may be built in Alaska, but they would compete with the Alaska Natural Gas Transportation System for available natural gas resources. BTL facilities are likely to be built where there are large supplies of biomass, such as crop residues and forestry waste. Because the BTL process uses cellulosic feedstocks, it is also modeled as a choice to meet the EISA2007 cellulosic biofuels requirement.

Coal Market Module

The Coal Market Module (CMM) simulates mining, transportation, and pricing of coal, subject to end-use demand for coal differentiated by heat and sulfur content. U.S. coal production is represented in the CMM by 40 separate supply curves—differentiated by region, mine type, coal rank, and sulfur content. The coal supply curves include a response to capacity utilization of mines, mining capacity, labor productivity, and factor input costs (mining equipment, mining labor, and fuel requirements). Projections of U.S. coal distribution are determined by minimizing the cost of coal supplied, given coal demands by demand region and sector, environmental restrictions, and accounting for minemouth prices, transportation costs, and coal supply contracts. Over the projection horizon, coal transportation costs in the CMM vary in response to changes in the cost of rail investments.

The CMM produces projections of U.S. steam and metallurgical coal exports and imports in the context of world coal trade, determining the pattern of world coal trade flows that minimizes the production and transportation costs of meeting a specified set of regional world coal import demands, subject to constraints on export capacities and trade flows. The international coal market component of the module computes trade in 3 types of coal for 17 export regions and 20 import regions. U.S. coal production and distribution are computed for 14 supply regions and 14 demand regions.

Annual Energy Outlook 2009 Cases

Table E1 provides a summary of the cases produced as part of the *AEO2009*. For each case, the table gives the name used in this report, a brief description of the major assumptions underlying the projections, the mode in which the case was run in NEMS (either fully integrated, partially integrated, or standalone), and a reference to the pages in the body of the report and in this appendix where the case is discussed. The text sections following Table E1 describe the various cases. The reference case assumptions for each sector are described in *Assumptions to the Annual Energy Outlook 2009* [*10*]. Regional results and other details of the projections are available at web site www.eia.doe.gov/oiaf/aeo/supplement.

Macroeconomic Growth Cases

In addition to the *AEO2009* reference case, the low economic growth and high economic growth cases were developed to reflect the uncertainty in projections of economic growth. The alternative cases are intended to show the effects of alternative growth assumptions on energy market projections. The cases are described as follows:

- The *low economic growth case* assumes lower growth rates for population (0.6 percent per year), nonfarm employment (0.5 percent per year), and labor productivity (1.5 percent per year), resulting in higher prices and interest rates and lower growth in industrial output. In the low economic growth case, economic output as measured by real GDP increases by 1.8 percent per year from 2007 through 2030, and growth in real disposable income per capita averages 1.5 percent per year.

- The *high economic growth case* assumes higher growth rates for population (1.3 percent per year), nonfarm employment (1.3 percent per year), and labor productivity (2.4 percent per year). With higher productivity gains and employment growth, inflation and interest rates are lower than in the reference case, and consequently economic output grows at a higher rate (3.0 percent per year) than in the reference case (2.5 percent). Disposable income per capita grows by 1.7 percent per year, compared with 1.6 percent in the reference case.

Oil Price Cases

The world oil price in *AEO2009* is defined as the average price of light, low-sulfur crude oil delivered in Cushing, Oklahoma, and is similar to the price for light, sweet crude oil traded on the New York Mercantile Exchange. *AEO2009* also includes a projection of the U.S. annual average refiners' acquisition cost of imported crude oil, which is more representative of the average cost of all crude oils used by refiners.

The historical record shows substantial variability in world oil prices, and there is arguably even more uncertainty about future prices in the long term. *AEO2009* considers three price cases (reference, low oil price, and high oil price) to allow an assessment of alternative views on the course of future oil prices. The low and high oil price cases define a wide range of potential price paths, reflecting different assumptions about decisions by OPEC members regarding the preferred rate of oil production and about the future finding and development costs and accessibility of conventional oil resources outside the United States. Because the low and high oil price cases are not fully integrated with a world economic model, the impact of world oil prices on international economies is not accounted for directly.

- In the *reference case*, real world oil prices rise from a low of $61 per barrel (2007 dollars) in 2009 to $110 per barrel in 2015, then increase more slowly to $130 per barrel in 2030. The reference case represents EIA's current judgment regarding exploration and development costs and accessibility of oil resources outside the United States. It also assumes that OPEC producers will choose to maintain their share of the market and will schedule investments in incremental production capacity so that OPEC's conventional oil production will represent about 40 percent of the world's total liquids production.

- In the *low oil price case*, real world oil prices are only $50 per barrel (2007 dollars) in 2030, compared with $130 per barrel in the reference case. The low oil price case assumes that OPEC countries will increase their conventional oil production to obtain approximately a 44-percent share of total world liquids production, and that oil resources outside the U.S. will be more accessible and/or less costly to produce (as a result of technology advances, more attractive fiscal regimes, or both) than in the reference case. With these assumptions, conventional oil production outside

Table E1. Summary of the *AEO2009* cases

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Reference	Baseline economic growth (2.5 percent per year from 2007 through 2030), world oil price, and technology assumptions. Complete projection tables in Appendix A.	Fully integrated	-	-
Low Economic Growth	Real GDP grows at an average annual rate of 1.8 percent from 2007 to 2030. Other energy market assumptions are the same as in the reference case. Partial projection tables in Appendix B.	Fully integrated	p. 58	p. 202
High Economic Growth	Real GDP grows at an average annual rate of 3.0 percent from 2007 to 2030. Other energy market assumptions are the same as in the reference case. Partial projection tables in Appendix B.	Fully integrated	p. 58	p. 202
Low Oil Price	More optimistic assumptions for economic access to non-OPEC resources and OPEC behavior than in the reference case. World light, sweet crude oil prices are $50 per barrel in 2030, compared with $130 per barrel in the reference case (2007 dollars). Other assumptions are the same as in the reference case. Partial projection tables in Appendix C.	Fully integrated	p. 60	p. 202
High Oil Price	More pessimistic assumptions for economic access to non-OPEC resources and OPEC behavior than in the reference case. World light, sweet crude oil prices are about $200 per barrel (2007 dollars) in 2030. Other assumptions are the same as in the reference case. Partial projection tables in Appendix C.	Fully integrated	p. 60	p. 202
Residential: 2009 Technology	Future equipment purchases based on equipment available in 2009. Existing building shell efficiencies fixed at 2009 levels. Partial projection tables in Appendix D.	With commercial	p. 63	p. 206
Residential: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Building shell efficiencies for new construction meet ENERGY STAR requirements after 2016. Partial projection tables in Appendix D.	With commercial	p. 63	p. 206
Residential: Best Available Technology	Future equipment purchases and new building shells based on most efficient technologies available by fuel. Building shell efficiencies for new construction meet the criteria for most efficient components after 2009. Partial projection tables in Appendix D.	With commercial	p. 64	p. 206
Commercial: 2009 Technology	Future equipment purchases based on equipment available in 2009. Building shell efficiencies fixed at 2009 levels. Partial projection tables in Appendix D.	With residential	p. 65	p. 206
Commercial: High Technology	Earlier availability, lower costs, and higher efficiencies for more advanced equipment. Building shell efficiencies for new and existing buildings increase by 8.8 and 6.3 percent, respectively, from 2003 values by 2030. Partial projection tables in Appendix D.	With residential	p. 65	p. 206
Commercial: Best Available Technology	Future equipment purchases based on most efficient technologies available by fuel. Building shell efficiencies for new and existing buildings increase by 10.5 and 7.5 percent, respectively, from 2003 values by 2030. Partial projection tables in Appendix D.	With residential	p. 66	p. 206

Table E1. Summary of the *AEO2008* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Industrial: 2009 Technology	Efficiency of plant and equipment fixed at 2009 levels. Partial projection tables in Appendix D.	Standalone	p. 178	p. 207
Industrial: High Technology	Earlier availability, lower costs, and higher efficiencies for more advanced equipment. Partial projection tables in Appendix D.	Standalone	p. 178	p. 207
Transportation: Low Technology	Advanced technologies are more costly and less efficient than in the reference case. Partial projection tables in Appendix D.	Standalone	p. 69	p. 207
Transportation: High Technology	Advanced technologies are less costly and more efficient than in the reference case. Partial projection tables in Appendix D.	Standalone	p. 69	p. 207
Electricity: Low Nuclear Cost	New nuclear capacity has 25 percent lower capital and operating costs in 2030 than in the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 181	p. 207
Electricity: High Nuclear Cost	Costs for new nuclear technology do not improve from 2009 levels in the reference case. Existing nuclear plants are retired after 55 years of service. Partial projection tables in Appendix D.	Fully integrated	p. 181	p. 208
Electricity: Low Fossil Technology Cost	Capital and operating costs for all new fossil-fired generating technologies improve by 25 percent in 2030 from reference case values. Partial projection tables in Appendix D.	Fully integrated	p. 182	p. 208
Electricity: High Fossil Technology Cost	Costs for new advanced fossil-fired generating technologies do not improve over time from 2009. Partial projection tables in Appendix D.	Fully integrated	p. 182	p. 208
Electricity: Frozen Plant Capital Costs	Base overnight costs for all new electric generating technologies are frozen at 2013 levels. Cost decreases due to learning still occur, but no declines in costs due to commodity price changes are assumed.	Fully integrated	p. 45	p. 208
Electricity: High Plant Capital Costs	Base overnight costs for all new electric generating technologies continue increasing throughout the projection, through a cost factor in 2030 that is 25 percentage points above the 2013 factor. Cost decreases due to learning can still occur and may partially offset the increases.	Fully integrated	p. 45	p. 208
Electricity: Falling Plant Capital Costs	Base overnight costs for all new electric generating technologies fall more rapidly than in the reference case, by assuming a cost factor 25 percentage points below the reference case cost factor in 2030.	Fully integrated	p. 45	p. 208
Renewable Fuels: High Renewable Technology Cost	New renewable generating technologies do not improve over time from 2009. Partial projection tables in Appendix D.	Fully integrated	p. 75	p. 208
Renewable Fuels: Low Renewable Technology Cost	Levelized cost of energy for nonhydropower renewable generating technologies declines by 25 percent in 2030 from reference case values. Partial projection tables in Appendix D.	Fully integrated	p. 75	p. 209
Renewable Fuels: Production Tax Credit Extension	Production Tax Credit for certain renewable generation is extended to projects constructed through 2019.	Fully integrated	p. 47	p. 209

Table E1. Summary of the *AEO2008* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Oil and Gas: Rapid Technology	Cost, finding rate, and success rate parameters are adjusted for 50 percent more rapid improvement than in the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 76	p. 209
Oil and Gas: Slow Technology	Cost, finding rate, and success rate parameters are adjusted for 50 percent slower improvement than in the reference case. Partial projection tables in Appendix D.	Fully Integrated	p. 76	p. 209
Oil and Gas: High LNG Supply	LNG imports are set exogenously to a factor times the reference case levels from 2010 forward, with the remaining assumptions unchanged from the reference case. The factor starts at 1.0 in 2010 and increases linearly to 5.0 in 2030. Partial projection tables in Appendix D.	Fully integrated	p. 192	p. 209
Oil and Gas: Low LNG Supply	LNG imports held constant at 2009 levels, with the remaining assumptions unchanged from the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 192	p. 209
Oil and Gas: ANWR	The Arctic National Wildlife Refuge (ANWR) in Alaska is opened to Federal oil and natural gas leasing, with the remaining assumptions unchanged from the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 193	p. 209
Oil and Gas: No Alaska Pipeline	A natural gas pipeline from the North Slope of Alaska to the lower 48 States is not built during the projection period.	Fully integrated	p. 78	p. 210
Oil and Gas: OCS Limited	Access to the Atlantic , Pacific , and Gulf of Mexico Outer Continental Shelf (OCS) is limited by reinstatement of leasing moratoria that lapsed in 2008.	Fully integrated	p. 35	p.210
Coal: Low Coal Cost	Productivity growth rates for coal mining are higher than in the reference case, and coal mining wages, mine equipment, and coal transportation rates are lower. Partial projection tables in Appendix D.	Fully integrated	p. 83	p. 210
Coal: High Coal Cost	Productivity growth rates for coal mining are lower than in the reference case, and coal mining wages, mine equipment, and coal transportation rates are higher. Partial projection tables in Appendix D.	Fully integrated	p. 83	p. 210
Integrated 2009 Technology	Combination of the residential, commercial, and industrial 2009 technology cases and the electricity high fossil technology cost, high renewable technology cost, and high nuclear cost cases. Partial projection tables in Appendix D.	Fully integrated	p. 176	p. 210
Integrated High Technology	Combination of the residential, commercial, industrial, and transportation high technology cases and the electricity low fossil technology cost, low renewable technology cost, and low nuclear cost cases. Partial projection tables in Appendix D.	Fully integrated	p. 176	p. 210
No GHG Concern	No greenhouse gas emissions reduction policy is enacted, and market investment decisions are not altered in anticipation of such a policy.	Fully integrated	p. 50	p. 211
LW110	Based on the greenhouse gas emissions reduction policy proposed by Senators Lieberman and Warner in the 110th Congress (S. 2191).	Fully integrated	p. 50	p. 211
No 2008 Tax Legislation	EIEA2008 tax legislation is removed from the reference case.	Fully integrated	p. 66	p. 211

the U.S. is higher in the low oil price case than in the reference case.

- In the *high oil price case*, real world oil prices reach about $200 per barrel (2007 dollars) in 2030. The high oil price case assumes that OPEC countries will reduce their production from the current rate, sacrificing market share as global liquids production increases, and that oil resources outside the United States will be less accessible and/or more costly to produce than assumed in the reference case.

Buildings Sector Cases

In addition to the *AEO2009* reference case, three standalone technology-focused cases using the Residential and Commercial Demand Modules of NEMS were developed to examine the effects of changes in equipment and building shell efficiencies.

For the residential sector, the three technology-focused cases are as follows:

- The *2009 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2009. Existing building shell efficiencies are assumed to be fixed at 2009 levels (no further improvements). For new construction, building shell technology options are constrained to those available in 2009.
- The *high technology case* assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment [*11*]. For new construction, building shell efficiencies are assumed to meet ENERGY STAR requirements after 2016.
- The *best available technology case* assumes that all future equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year for each fuel, regardless of cost. For new construction, building shell efficiencies are assumed to meet the criteria for the most efficient components after 2009.

For the commercial sector, the three technology-focused cases are as follows:

- The *2009 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2009. Building shell efficiencies are assumed to be fixed at 2009 levels.
- The *high technology case* assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than in the reference case [*12*]. Building shell efficiencies for new and existing buildings in 2030 are assumed to be 8.8 percent and 6.3 percent higher, respectively, than their 2003 levels—a 25-percent improvement relative to the reference case.
- The *best available technology case* assumes that all future equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year for each fuel, regardless of cost. Building shell efficiencies for new and existing buildings in 2030 are assumed to be 10.5 percent and 7.5 percent higher, respectively, than their 2003 values—a 50-percent improvement relative to the reference case.

The Residential and Commercial Demand Modules of NEMS were also used to complete the high and low renewable technology cost cases, which are discussed in more detail below in the Renewable Fuels Cases section. In combination with assumptions for electricity generation from renewable fuels in the electric power sector and industrial sector, these sensitivity cases analyze the impacts of changes in generating technologies that use renewable fuels and in the availability of renewable energy sources. For the Residential and Commercial Demand Modules:

- The *low renewable technology cost case* assumes greater improvements in residential and commercial PV and wind systems than in the reference case. The assumptions result in capital cost estimates for 2030 that are approximately 25 percent lower than reference case costs for distributed PV technologies.
- The *high renewable technology cost case* assumes that costs and performance levels for residential and commercial PV and wind systems remain constant at 2009 levels through 2030.

Industrial Sector Cases

In addition to the *AEO2009* reference case, two standalone cases using the Industrial Demand Module of NEMS were developed to examine the effects of less rapid and more rapid technology change and adoption. Because they are standalone cases, the energy intensity changes discussed in this section exclude the refining industry. Energy use in the refining industry is estimated as part of the Petroleum Market Module in NEMS. The Industrial Demand Module also was used as part of the integrated low and high renewable technology cost cases. For the industrial sector:

- The *2009 technology case* holds the energy efficiency of plant and equipment constant at the 2009 level over the projection period. In this case, delivered energy intensity falls by 1.1 percent annually from 2007 to 2030, as compared with 1.5 percent annually in the reference case. Changes in aggregate energy intensity may result both from changing equipment and production efficiency and from changing composition of industrial output. Because the level and composition of industrial output are the same in the reference, 2009 technology, and high technology cases, any change in energy intensity in the two technology cases is attributable to efficiency changes.
- The *high technology case* assumes earlier availability, lower costs, and higher efficiency for more advanced equipment [*13*] and a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes (0.7 percent per year, as compared with 0.4 percent per year in the reference case). The same assumption is incorporated in the integrated low renewable technology cost case, which focuses on electricity generation. Although the choice of the 0.7-percent annual rate of improvement in byproduct recovery is an assumption in the high technology case, it is based on the expectation that there would be higher recovery rates and substantially increased use of CHP in that case. Delivered energy intensity falls by 1.7 percent annually in the high technology case.

The 2009 technology case was run with only the Industrial Demand Module, rather than in fully integrated NEMS runs. Consequently, no potential feedback effects from energy market interactions are captured, and energy consumption and production in the refining industry, which are modeled in the PMM, are excluded.

Transportation Sector Cases

In addition to the *AEO2009* reference case, two standalone cases using the NEMS Transportation Demand Module were developed to examine the effects of advanced technology costs and efficiency improvement on technology adoption and vehicle fuel economy [*14*]. For the transportation sector:

- In the *low technology case,* the characteristics of conventional technologies, advanced technologies, and alternative-fuel LDVs, heavy-duty vehicles, and aircraft reflect more pessimistic assumptions about cost and efficiency improvements achieved over the projection. More pessimistic assumptions for fuel efficiency improvement are also reflected in the rail and shipping sectors.
- In the *high technology case*, the characteristics of conventional and alternative-fuel light-duty vehicles reflect more optimistic assumptions about incremental improvements in fuel economy and costs. In the freight truck sector, the high technology case assumes more rapid incremental improvement in fuel efficiency for engine and emissions control technologies. More optimistic assumptions for fuel efficiency improvements are also made for the air, rail, and shipping sectors.

The low technology and high technology cases were run with only the Transportation Demand Module rather than as fully integrated NEMS runs. Consequently, no potential macroeconomic feedback related to vehicles costs or travel demand was captured, nor were changes in fuel prices incorporated.

Electricity Sector Cases

In addition to the reference case, several integrated cases with alternative electric power assumptions were developed to analyze uncertainties about the future costs and performance of new generating technologies. Two of the cases examine alternative assumptions for nuclear power technologies, and two examine alternative assumptions for fossil fuel technologies. Three additional cases examine alternative cost paths for all technologies, based on uncertainties in the underlying commodity prices that influence power plant construction costs. Reference case values for technology characteristics are determined in consultation with industry and government specialists; however, there is always uncertainty surrounding the major component costs. The electricity cases analyze what could happen if costs of new plants were either higher or lower than assumed in the reference case. The cases are fully integrated to allow feedback between the potential shifts in fuel consumption and fuel prices.

Nuclear Technology Cost Cases

- The cost assumptions for the *low nuclear cost case* reflect a 25-percent reduction in the capital and operating costs for advanced nuclear technology in 2030, relative to the reference case. The reference case projects a 29-percent reduction in the capital costs of nuclear power plants from 2009 to 2030; the low nuclear cost case assumes a 46-percent reduction from 2009 to 2030.

- The *high nuclear cost case* assumes that capital costs for the advanced nuclear technology do not decline during the projection period but remain fixed at the 2009 levels assumed in the reference case. This case also assumes that existing nuclear plants are retired after 55 years of operation, as compared with a maximum 60-year life in the reference case. There is considerable uncertainty surrounding the technical lifetime for some of the major components of older nuclear plants.

Fossil Cost Technology Cases

- In the *low fossil technology cost case*, capital costs and operating costs for all coal- and natural-gas-fired generating technologies are assumed to be 25 percent lower than reference case levels in 2030. Because learning in the reference case reduces costs with manufacturing experience, costs in the low fossil cost case are reduced by 40 to 47 percent between 2009 and 2030, depending on the technology.
- In the *high fossil technology cost case*, capital costs for all coal- and natural-gas-fired generating technologies do not decline during the projection period but remain fixed at the 2009 values assumed in the reference case.

Additional details about annual capital costs, operating and maintenance costs, plant efficiencies, and other factors used in the high and low fossil technology cost cases will be provided in *Assumptions to the Annual Energy Outlook 2009* [*15*].

Electricity Plant Capital Cost Cases

The costs to build new power plants have risen dramatically in the past few years, primarily as a result of significant increases in the costs of construction-related materials, such as cement, iron, steel, and copper. For the *AEO2009* reference case, initial overnight costs for all technologies were updated to be consistent with costs estimates in the early part of 2008. A cost adjustment factor based on the projected producer price index for metals and metal products was also implemented, allowing the overnight costs to fall in the future if the index drops, or to rise further if the index increases. Although there is significant correlation between commodity prices and power plant construction costs, other factors may influence future costs, raising the uncertainties surrounding the future costs of building new power plants. For *AEO2009*, three additional cost cases focus on the uncertainties of future plant construction costs. The three cases use exogenous assumptions for the annual adjustment factors, rather than linking to the metals price index. The cases are discussed in "Electricity Plant Cost Uncertainties" in the Issues in Focus section of this report.

- In the *frozen plant capital costs case,* base overnight costs for all new generating technologies are assumed to be frozen at 2013 levels. Cost decreases still can occur with learning. In this case, costs do decline slightly over the projection, but capital costs are roughly 20 percent above reference case costs in 2030.
- In the *high plant capital costs case*, base overnight costs for all new generating technologies are assumed to continue increasing throughout the projection, with the cost factor increasing by 25 percentage points from 2013 to 2030. Cost decreases still can occur with learning, and they may partially offset the increases, but costs for most technologies in 2030 are above current costs and about 50 percent higher than projected costs in 2030 in the reference case.
- In the *falling plant capital costs case*, base overnight costs for all new generating technologies are assumed to fall more rapidly than in the reference case, starting in 2013. In 2030, the cost factor is assumed to be 25 percentage points below the reference case value.

Renewable Fuels Cases

In addition to the *AEO2009* reference case, two integrated cases with alternative assumptions about renewable fuels were developed to examine the effects of less aggressive and more aggressive improvement in the cost of renewable technologies. The cases are as follows:

- In the *high renewable technology cost case*, capital costs, operating and maintenance costs, and performance levels for wind, solar, biomass, and geothermal resources are assumed to remain constant at 2009 levels through 2030. Although biomass prices are not changed from the reference case, this case assumes that dedicated energy crops (also known as "closed-loop" biomass fuel supply) do not become available.

- In the *low renewable technology cost case*, the levelized costs of energy resources for generating technologies using renewable resources are assumed to decline to 25 percent below the reference case costs for the same resources in 2030. In general, lower costs are represented by reducing the capital costs of new plant construction. Biomass fuel supplies also are assumed to be 25 percent less expensive than in the reference case for the same resource quantities used in the reference case. Assumptions for other generating technologies are unchanged from those in the reference case. In the low renewable technology cost case, the rate of improvement in recovery of biomass byproducts from industrial processes is also increased.
- In the *production tax credit extension case,* an additional extension of the PTC is provided to all eligible resources modeled in *AEO2009*. In this case, plants entering service by December 31, 2019, are assumed to be eligible for the PTC. Under current law as of December 2008, the PTC for certain renewable generation technologies, including geothermal, biomass, hydroelectric, and landfill gas, will not be available for plants constructed after December 31, 2010. For wind, the PTC will not be available to plants constructed after December 31, 2009. This law has been renewed periodically, however, either before or within a several months after its expiration.

Oil and Gas Supply Cases

The sensitivity of the projections to changes in the assumed rates of technological progress in oil and natural gas supply and LNG imports are examined in four cases:

- In the *rapid technology case*, the parameters representing the effects of technological progress on finding rates, drilling costs, lease equipment and operating costs, and success rates for conventional oil and natural gas drilling in the reference case are improved by 50 percent. Improvements in a number of key exploration and production technologies for unconventional natural gas also are increased by 50 percent in the rapid technology case. Key supply parameters for Canadian oil and natural gas also are modified to simulate the assumed impacts of more rapid oil and natural gas technology penetration on Canadian supply potential. All other parameters in the model are kept at the reference case values, including technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about imports and exports of LNG and natural gas trade between the United States and Mexico. Specific detail by region and fuel category is provided in *Assumptions to the Annual Energy Outlook 2009* [*16*].
- In the *slow technology case*, the parameters representing the effects of technological progress on finding rates, drilling, lease equipment and operating costs, and success rates for conventional oil and natural gas drilling are 50 percent less optimistic than those in the reference case. Improvements in a number of key exploration and production technologies for unconventional natural gas also are reduced by 50 percent in the slow technology case. Key Canadian supply parameters also are modified to simulate the assumed impacts of slow oil and natural gas technology penetration on Canadian supply potential. All other parameters in the model are kept at the reference case values.
- The *high LNG supply case* exogenously specifies LNG import levels for 2010 through 2030 equal to a factor times the reference case levels. The factor starts at 1 in 2010 and increases linearly to 5 in 2030. The intent is to project the potential impact on domestic natural gas markets if LNG imports turn out to be higher than projected in the reference case.
- The *low LNG supply case* exogenously specifies LNG imports at the 2009 levels projected in the reference case for the period 2010 through 2030. The intent is to project the potential impact on domestic natural gas markets if LNG imports turn out to be lower than projected in the reference case.

Additional cases show the potential impacts of lifting leasing restrictions in the Arctic National Wildlife Refuge (ANWR), of conditions that result in no construction of an Alaska pipeline before 2030, and of reinstating the Outer Continental Shelf (OCS) leasing moratoria that expired on September 30, 2008.

- The *ANWR case* assumes that Federal legislation passed during 2009 permits Federal oil and gas leasing in ANWR's 1002 area, and that oil and natural gas leasing will commence after 2009 in the State and Native lands that are either in or adjoining ANWR.

- The *no Alaska pipeline case* examines the natural gas market impacts of assuming that a pipeline to move North Slope gas from Alaska to the lower 48 States is not constructed during the projection period. Currently, there are no specific prohibitions on the construction of such a pipeline; however, political, business, and/or economic factors could lead to indefinite postponement of the project.
- The *OCS limited case* assumes that the OCS leasing allowed by Congress to expire on September 30, 2008, does not expire and will continue to be renewed annually throughout the projection period, thus prohibiting offshore drilling for oil and natural gas in the Pacific, the Atlantic, most of the Eastern Gulf of Mexico, and a small area in the Central Gulf of Mexico OCS. In the OCS limited case, technically recoverable resources in the OCS total 75 billion barrels of oil and 380 trillion cubic feet of natural gas, as compared with 93 billion barrels and 456 trillion cubic feet in the reference case.

Coal Market Cases

Two alternative coal cost cases examine the impacts on U.S. coal supply, demand, distribution, and prices that result from alternative assumptions about mining productivity, labor costs, mine equipment costs, and coal transportation rates. The alternative productivity and cost assumptions are applied in every year from 2010 through 2030. For the coal cost cases, adjustments to the reference case assumptions for coal mining productivity are based on variation in the average annual productivity growth of 3.6 percent observed since 1980. Transportation rates are lowered (in the low cost case) or raised (in the high cost case) from reference case levels to achieve a 25-percent change in rates relative to the reference case in 2030. The low and high coal cost cases represent fully integrated NEMS runs, with feedback from the macroeconomic activity, international, supply, conversion, and end-use demand modules.

- In the *low coal cost case*, the average annual growth rates for coal mining productivity are higher than those in the reference case and are applied at the supply curve level. As an example, the average annual growth rate for Wyoming's Southern Powder River Basin supply curve is increased from -0.5 percent in the reference case for the years 2010 through 2030 to 3.1 percent in the low coal cost case. Coal mining wages, mine equipment costs, and other mine supply costs all are assumed to be about 20 percent lower in 2030 in real terms in the low coal cost case than in the reference case. Coal transportation rates, excluding the impact of fuel surcharges, are assumed to be 25 percent lower in 2030.
- In the *high coal cost case*, the average annual productivity growth rates for coal mining are lower than those in the reference case and are applied as described in the *low coal cost case*. Coal mining wages, mine equipment costs, and other mine supply costs in 2030 are assumed to be about 20 percent higher than in the reference case, and coal transportation rates in 2030 are assumed to be 25 percent higher.

Additional details about the productivity, wage, mine equipment cost, and coal transportation rate assumptions for the reference and alternative coal cost cases are provided in Appendix D.

Cross-Cutting Integrated Cases

In addition to the sector-specific cases described above, a series of cross-cutting integrated cases are used in *AEO2009* to analyze specific scenarios with broader sectoral impacts. For example, two integrated technology progress cases combine the assumptions from the other technology progress cases to analyze the broader impacts of more rapid and slower technology improvement rates. In addition, two cases also were run with alternative assumptions about future regulation of GHG emissions.

Integrated Technology Cases

The *integrated 2009 technology case* combines the assumptions from the residential, commercial, and industrial 2009 technology cases and the electricity high fossil technology cost, high renewable technology cost, and high nuclear cost cases. The *integrated high technology case* combines the assumptions from the residential, commercial, industrial, and transportation high technology cases and the electricity high fossil technology cost, low renewable technology cost, and low nuclear cost cases.

Greenhouse Gas Uncertainty Cases

Although currently no legislation restricting GHG emissions is in place in the United States, regulators and the investment community are beginning to push energy companies to invest in less GHG-intensive technologies, as captured in the reference case by assuming a 3-percentage-point increase in the cost of capital for investments in new coal-fired power plants without CCS and new CTL plants. Those assumptions affect cost evaluations for the construction of new capacity but not the actual operating costs when a new plant begins operation.

Two alternative cases are used to provide a range of outcomes, from no concern about future GHG legislation to the imposition of a specific GHG limit. The *no GHG concern case*, which was run without any adjustment for concern about potential GHG regulations, is similar to the reference cases from previous *AEO*s (without the 3-percentage-point increase). In the no GHG concern case, the same cost of capital is used to evaluate all new capacity builds, regardless of type. The *LW110 case* assumes implementation of a GHG emissions reduction policy that affects both investment and operating costs. Assumptions for the LW110 case are based on S. 2191, the Lieberman-Warner Climate Security Act of 2007 in the 110th Congress, as modeled in an earlier EIA analysis [*17*]. Results from the LW110 case should be viewed as illustrative, because the impact of any policy to reduce GHG emissions will depend on its detailed specifications, which are likely to differ from those in the LW110 case.

No 2008 Tax Legislation Case

Because the *AEO2009* reference case includes the tax provisions from EIEA2008 [*18*], a *no 2008 tax legislation case* is used to examine the impacts of those specific tax provisions.

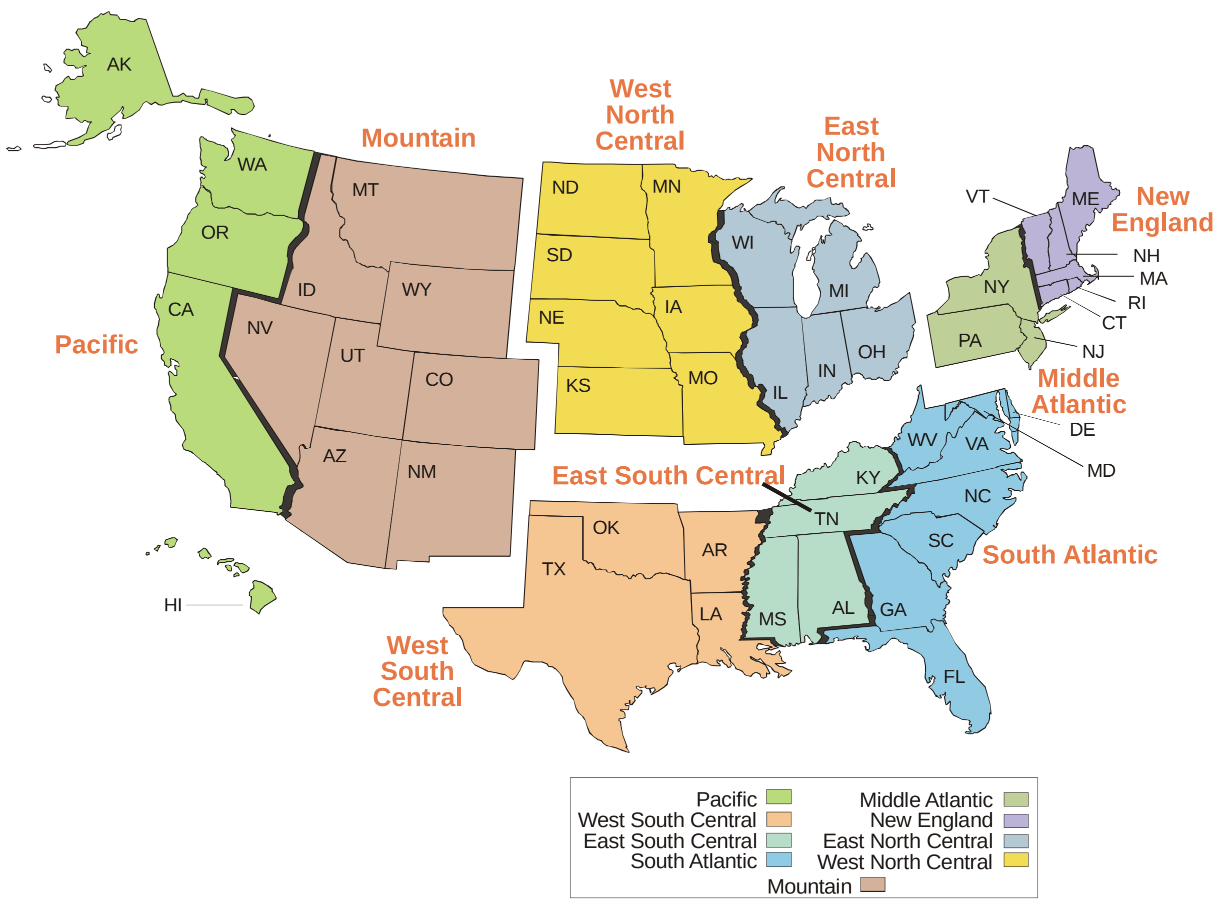
Endnotes

1. Energy Information Administration, *The National Energy Modeling System: An Overview 2003*, DOE/EIA-0581(2003) (Washington, DC, March 2003), web site www.eia.doe.gov/oiaf/aeo/overview.
2. For *AEO2010*, the projection period is expected to be extended to 2035.
3. Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008), web site www.eia.doe.gov/emeu/aer/contents.html.
4. Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2007*, DOE/EIA-0573(2007) (Washington, DC, December, 2008), web site www.eia.doe.gov/oiaf/1605/ggrpt/index.html.
5. Energy Information Administration, *Short-Term Energy Outlook*, web site www.eia.doe.gov/emeu/steo/pub/contents.html. Portions of the preliminary information were also used to initialize the NEMS Petroleum Market Module projection.
6. Jet Information Services, Inc., *World Jet Inventory Year-End 2006* (Utica, NY, March 2007); and personal communication from Stuart Miller (Jet Information Services).
7. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2009*, DOE/EIA-0554 (2009) (Washington, DC, March 2009), web site www.eia.doe.gov/oiaf/aeo/assumption.
8. For gasoline blended with ethanol, the tax credit of 51 cents (nominal) per gallon of ethanol is assumed to be available for 2008; however, it is reduced to 45 cents starting in 2009 (the year after annual U.S. ethanol consumption surpasses 7.5 billion gallons), as mandated by the Food, Conservation, and Energy Act of 2008 (the Farm Bill), and it is set to expire after 2010. In addition, modeling updates include the Farm Bill's mandated extension of the ethanol import tariff, at 54 cents per gallon, to December 31, 2010. Finally, again in accordance with the Farm Bill, a new cellulosic ethanol producer's tax credit of $1.01 per gallon, valid through 2012, is implemented in the model; however, it is reduced by the amount of the blender's tax credit amount. Thus, in 2009 and 2010, the cellulosic ethanol producer's tax credit is modeled as $1.01 - $0.45 = $0.56 per gallon, and in 2011 and 2012 it is set at $1.01 per gallon.
9. California Environmental Protection Agency, Air Resources Board, "Phase 3 California Reformulated Gasoline Regulations," web site www.arb.ca.gov/regact/2007/carfg07/carfg07.htm.
10. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2009*, DOE/EIA-0554 (2009) (Washington, DC, March 2009), web site www.eia.doe.gov/oiaf/aeo/assumption.
11. High technology assumptions for the residential sector are based on Energy Information Administration, *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case Second Edition (Revised)* (Navigant Consulting, Inc., September 2007), and *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case: Residential and Commercial Lighting, Commercial Refrigeration, and Commercial Ventilation Technologies* (Navigant Consulting, Inc., September 2008).
12. High technology assumptions for the commercial sector are based on Energy Information Administration, *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case Second Edition (Revised)* (Navigant Consulting, Inc., September 2007), and *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case: Residential and Commercial Lighting, Commercial Refrigeration, and Commercial Ventilation Technologies* (Navigant Consulting, Inc., September 2008).

13. These assumptions are based in part on Energy Information Administration, *Industrial Technology and Data Analysis Supporting the NEMS Industrial Model* (FOCIS Associates, October 2005).
14. Energy Information Administration, *Documentation of Technologies Included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (Energy and Environmental Analysis, September 2003).
15. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2009*, DOE/EIA-0554 (2009) (Washington, DC, March 2009), web site www.eia.doe.gov/oiaf/aeo/assumption.
16. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2009*, DOE/EIA-0554 (2009) (Washington, DC, March 2009), web site www.eia.doe.gov/oiaf/aeo/assumption.
17. See Energy Information Administration, *Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007*, SR/OIAF/2008-01 (Washington, DC, April 2008), web site www.eia.doe.gov/oiaf/servicerpt/s2191/pdf/sroiaf(2008)01.pdf.
18. See pages 9-12 in the Legislation and Regulations section of this report.

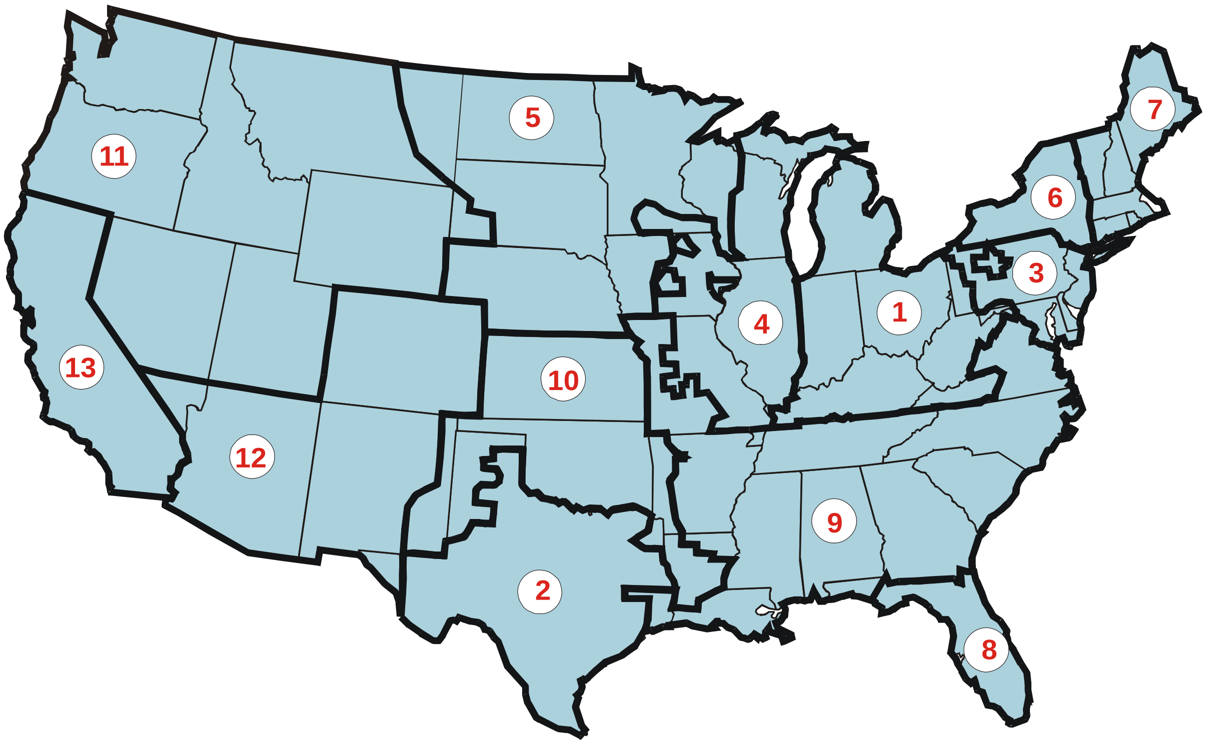
Regional Maps

F1. United States Census Divisions



Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

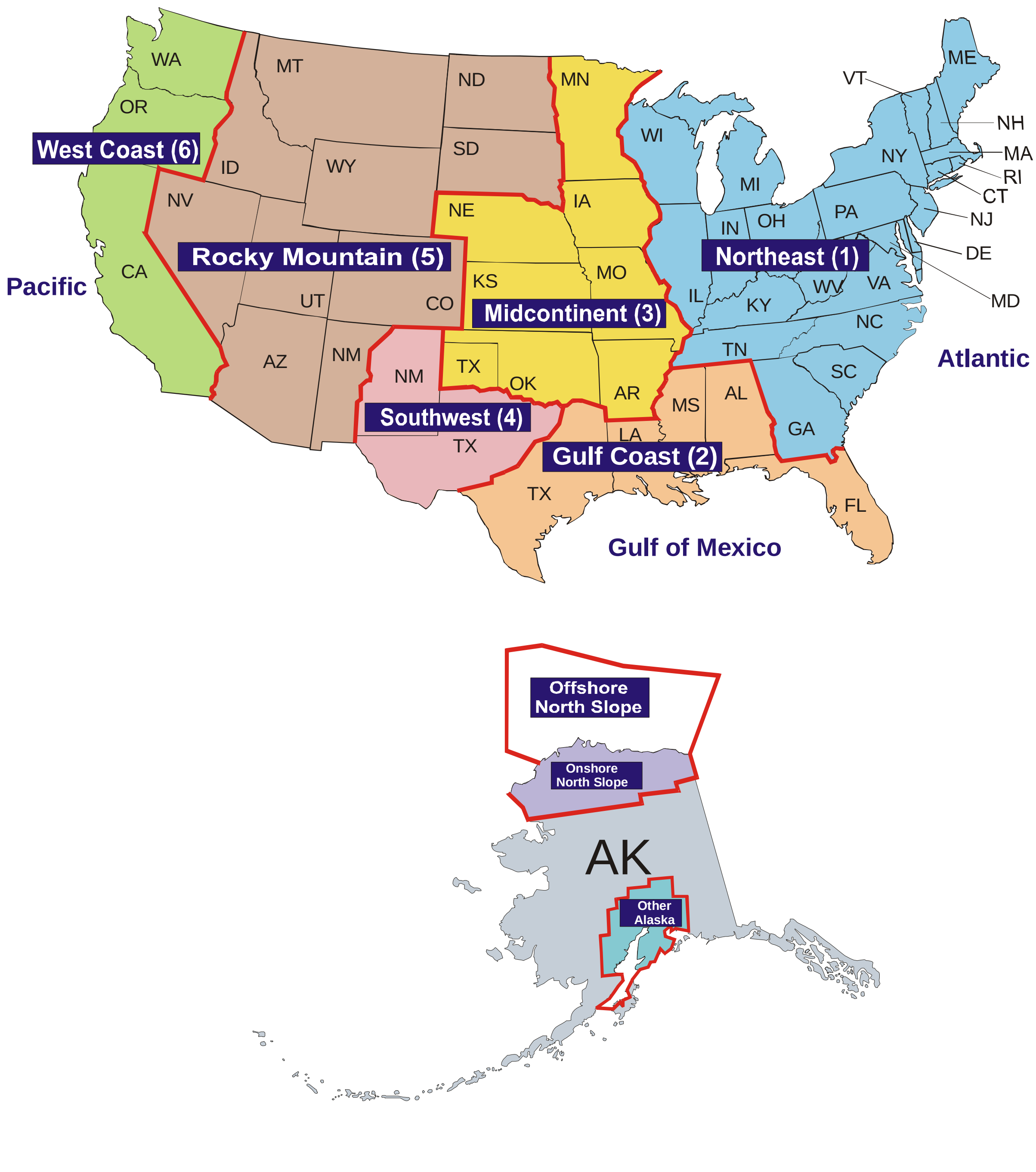
F2. Electricity Market Module Regions



1 East Central Area Reliability Coordination Agreement (ECAR)
2 Electric Reliability Council of Texas (ERCOT)
3 Mid-Atlantic Area Council (MAAC)
4 Mid-America Interconnected Network (MAIN)
5 Mid-Continent Area Power Pool (MAPP)
6. New York (NY)
7. New England (NE)
8. Florida Reliability Coordinating Council (FL)
9. Southeastern Electric Reliability Council (SEF
10. Southwest Power Pool (SPP)
11. Northwest Power Pool (NWP)
12. Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada (RA)
13. California (CA)

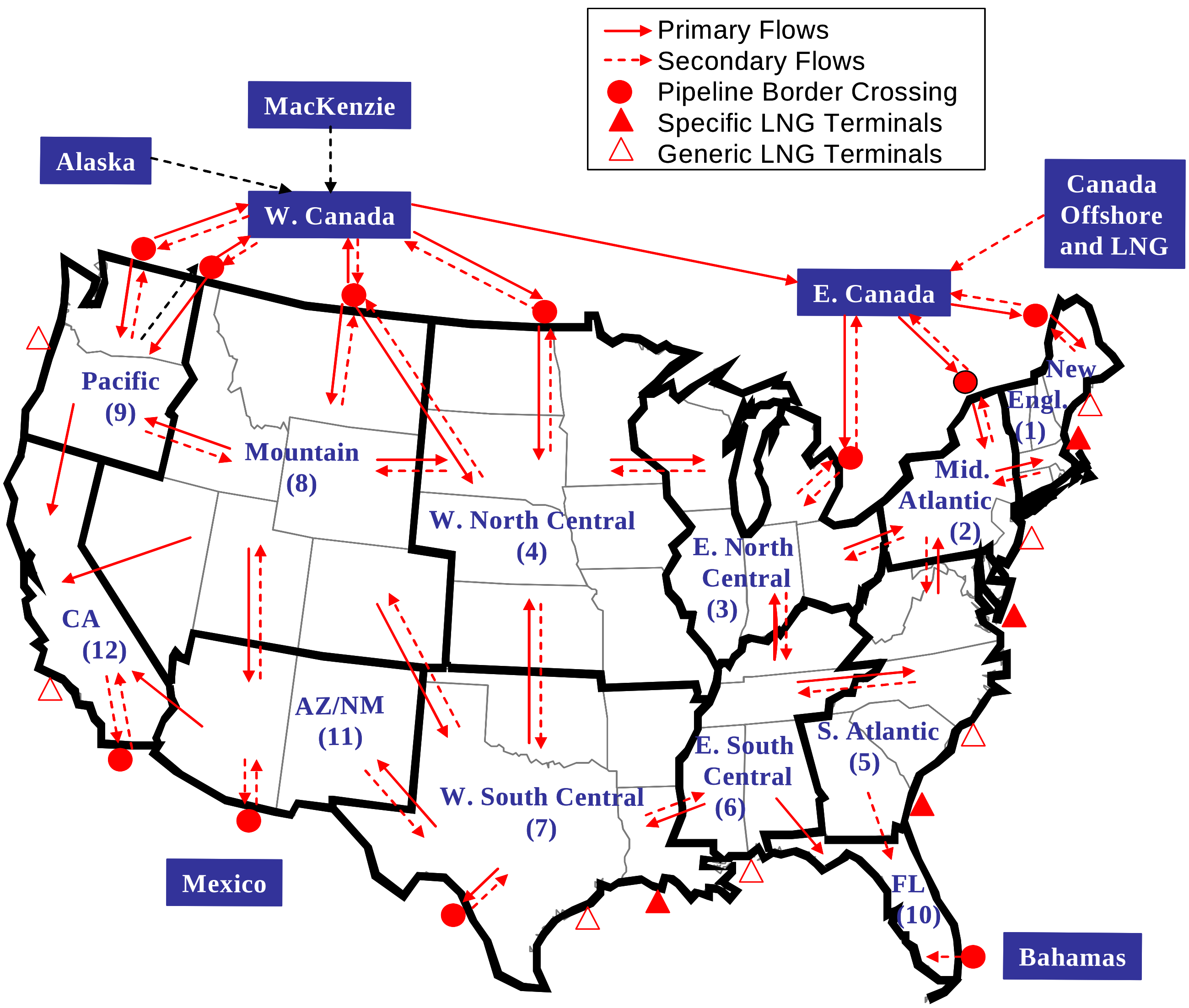
Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

F3. Oil and Gas Supply Model Regions



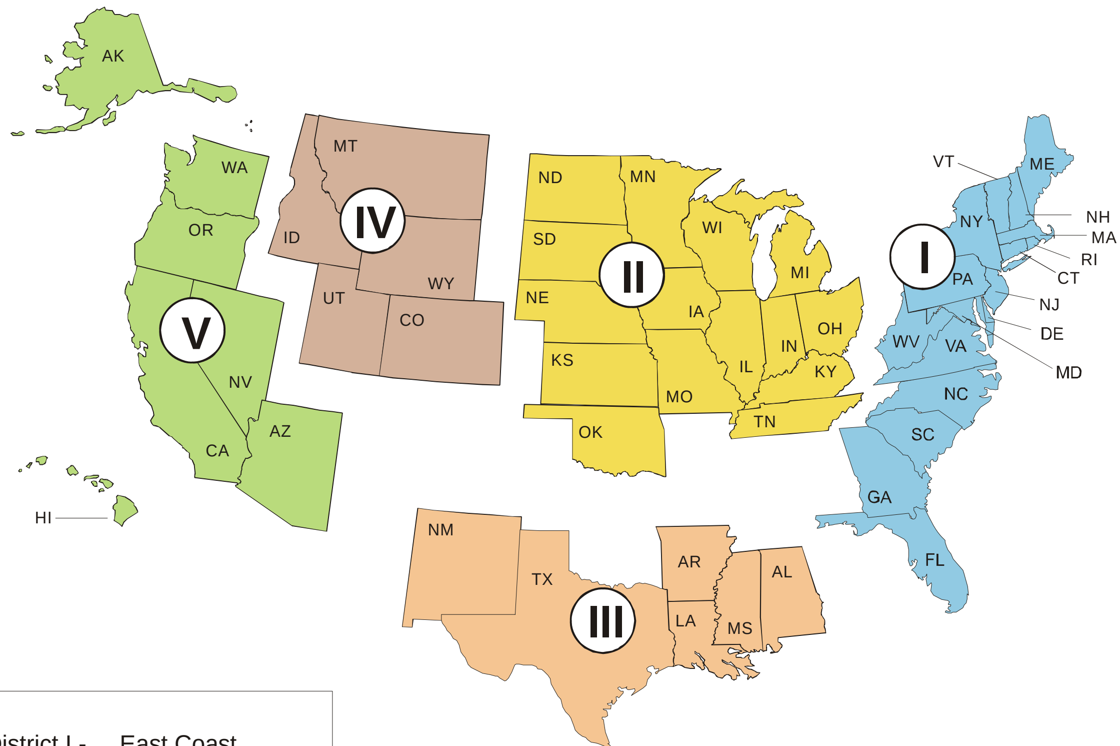
Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

F4. Natural Gas Transmission and Distribution Model Regions



Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

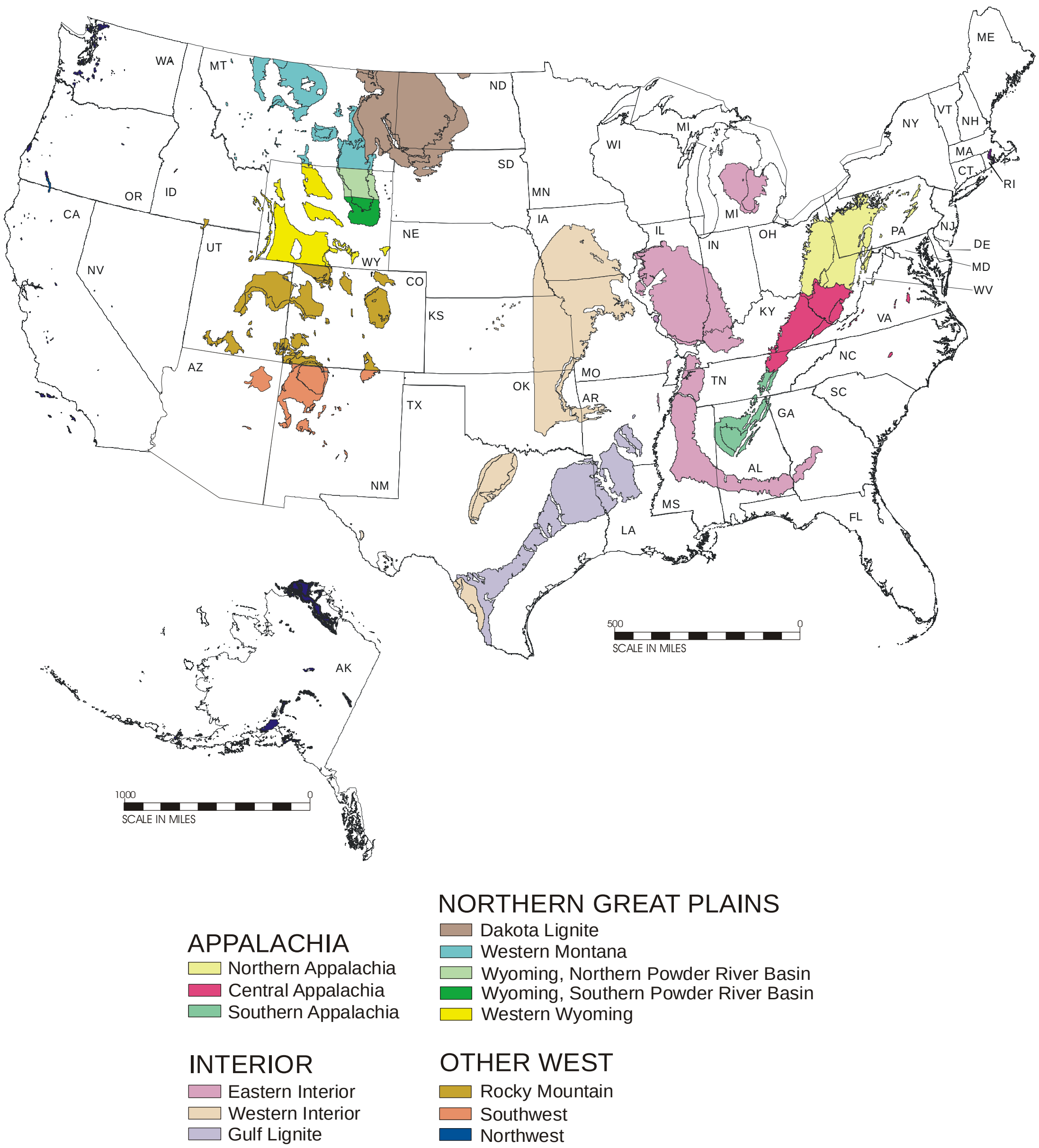
F5. Petroleum Administration for Defense Districts



PAD District I - East Coast
PAD District II - Midwest
PAD District III - Gulf Coast
PAD District IV - Rocky Mountain
PAD District V - West Coast

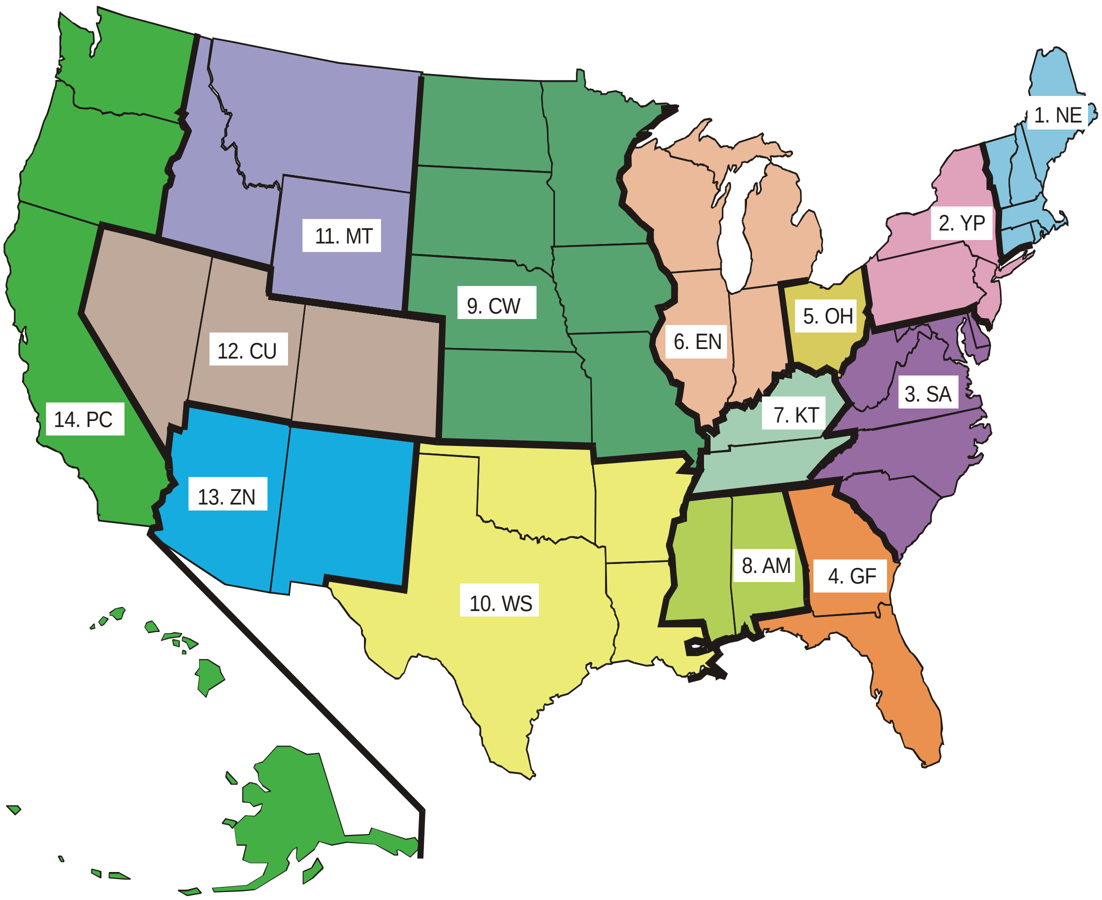
Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

F6. Coal Supply Regions



Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

F7. Coal Demand Regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. SA	WV,MD,DC,DE,VA,NC,SC
4. GF	GA,FL
5. OH	OH
6. EN	IN,IL,MI,WI
7. KT	KY,TN

Region Code	Region Content
8. AM	AL,MS
9. CW	MN,IA,ND,SD,NE,MO,KS
10. WS	TX,LA,OK,AR
11. MT	MT,WY,ID
12. CU	CO,UT,NV
13. ZN	AZ,NM
14. PC	AK,HI,WA,OR,CA

Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

Conversion Factors

Table G1. Heat Rates

Fuel	Units	Approximate Heat Content
Coal[1]		
Production	million Btu per short ton	20.341
Consumption	million Btu per short ton	20.165
Coke Plants	million Btu per short ton	26.325
Industrial	million Btu per short ton	22.312
Residential and Commercial	million Btu per short ton	21.235
Electric Power Sector	million Btu per short ton	19.911
Imports	million Btu per short ton	25.066
Exports	million Btu per short ton	25.524
Coal Coke	million Btu per short ton	24.800
Crude Oil		
Production	million Btu per barrel	5.800
Imports[1]	million Btu per barrel	5.981
Liquids		
Consumption[1]	million Btu per barrel	5.337
Motor Gasoline[1]	million Btu per barrel	5.157
Jet Fuel	million Btu per barrel	5.670
Distillate Fuel Oil[1]	million Btu per barrel	5.780
Diesel Fuel[1]	million Btu per barrel	5.769
Residual Fuel Oil	million Btu per barrel	6.287
Liquefied Petroleum Gases[1]	million Btu per barrel	3.591
Kerosene	million Btu per barrel	5.670
Petrochemical Feedstocks[1]	million Btu per barrel	5.562
Unfinished Oils	million Btu per barrel	6.118
Imports[1]	million Btu per barrel	5.558
Exports[1]	million Btu per barrel	5.745
Ethanol	million Btu per barrel	3.539
Biodiesel	million Btu per barrel	5.376
Natural Gas Plant Liquids		
Production[1]	million Btu per barrel	3.701
Natural Gas[1]		
Production, Dry	Btu per cubic foot	1,028
Consumption	Btu per cubic foot	1,028
End-Use Sectors	Btu per cubic foot	1,028
Electric Power Sector	Btu per cubic foot	1,028
Imports	Btu per cubic foot	1,025
Exports	Btu per cubic foot	1,009
Electricity Consumption	Btu per kilowatthour	3,412

[1]Conversion factor varies from year to year. The value shown is for 2007.
Btu = British thermal unit.
Sources: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008), and EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

RE-EVALUATION
OF THE
FINAL ENVIRONMENTAL IMPACT STATEMENT

FOR

State Highway 99
Grand Parkway
Segment F-1
FROM: US 290
TO: SH 249

HARRIS COUNTY, TEXAS

CSJs: 3510-06-002,
3510-06-900, and 3510-06-902

U.S. DEPARTMENT OF TRANSPORTATION
FEDERAL HIGHWAY ADMINISTRATION

and

TEXAS DEPARTMENT OF TRANSPORTATION

JUNE 2009

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1.0 INTRODUCTION

This document is a Re-evaluation of the approved State Highway (SH) 99, Grand Parkway, Segment F-1 Final Environmental Impact Statement (FEIS) for the construction of a 11.9-mile new location, four-lane, controlled access toll road with intermittent frontage roads within a 400-foot right-of-way (ROW) from United States Highway (US) 290 to State Highway (SH) 249 in Harris County, Texas. The Federal Highway Administration (FHWA) and the Texas Department of Transportation (TxDOT) jointly approved the FEIS for the project in March 2008. A Record of Decision (ROD) was issued by FHWA on November 20, 2008.

As described in the ROD, the project consists of the construction of a four-lane, divided toll road on new location from the existing terminus of US 290 to SH 249 through Harris County. The project limits and approved alignment are shown on an aerial photograph in **Exhibit 1** of **Appendix A**. The approved design consists of two 12-foot travel lanes in each direction with a 40-foot median and intermittent frontage roads occurring within a ROW width of 400 feet. The ROW footprint area is approximately 616 acres. The crossing of Little Cypress Creek and Willow Creek would be accomplished by bridges (one in each direction) at both locations and the crossing of six tributaries to these streams would be culverted.

This Re-evaluation is necessary because of a design revision that has occurred subsequent to the ROD as depicted in **Exhibit 1** of **Appendix A**. A complete description of the design change is stated in **Section 5.0** of this Re-evaluation. The project design revision includes one additional grade separation at future Mason Road. This design feature requires no additional ROW or easements in addition to the original 400-foot ROW studied in the ROD. The schematic design plans (**Exhibit 2** of **Appendix A**) for the grade separation at future Mason Road between Schiel Road and Muschke Road have been changed. The remainder of the project and the 400-foot ROW, as discussed in the ROD, remain unchanged.

The purpose of this Re-evaluation is to describe the project design revision that occurred after the issuance of the ROD, evaluate how this design revision affects the previous environmental impacts analysis, and determine whether a new and comprehensive analysis of the entire project is needed. This Re-evaluation complies with FHWA regulations (23 Code of Federal Regulations [CFR] 771.129) and includes updates to regulations or guidance and progress to commitments and permits in the ROD.

The need and purpose of the project remain as stated and explained in the ROD. To summarize, there are inefficient connections between suburban communities and major radial roadways (system linkage), the current and future transportation demand exceeds capacity, many roadways in the study area have a high accident rate, and there is an increasing strain on transportation infrastructure from population and economic growth. The purpose of the transportation improvements is to efficiently link the suburban communities and major roadways, enhance mobility and safety, and respond to economic growth. See FEIS, Volume I, Section 1.1 for further details regarding need for and purpose of the project.

2.0 PROJECT HISTORY

The Grand Parkway was first proposed in 1961 by Harris County and the City of Houston Planning Commission following traffic studies that identified regional transportation deficiencies. The Grand Parkway corridor was placed on city maps in 1968, but funds were not available to advance the project. With the development of the Houston metropolitan area, the Katy area, and other residential and corporate facilities in West Houston, the need for additional transportation facilities increased. County officials and landowners mapped a proposed corridor for the Grand Parkway and submitted the plan to the Texas Transportation Commission.

In 1984, the Texas Legislature authorized the creation and organization of a nonprofit transportation corporation to act on behalf of TxDOT in the development of public transportation facilities and systems within the state. The Grand Parkway Association (GPA), the first of these corporations created, was charged with assisting the Texas Transportation Commission in obtaining land and funding to meet the planning, legal, engineering, and ROW requirements of the Grand Parkway. Since its inception, the GPA has worked directly with landowners, local and state governmental agencies, elected officials, and the public to complete the Grand Parkway.

The proposed SH 99, Grand Parkway is planned as an approximate 184-mile circumferential facility (a roadway loop such as Beltway 8) around the Houston metropolitan area. The entire proposed facility traverses Harris, Montgomery, Liberty, Chambers, Galveston, Brazoria, and Fort Bend Counties, Texas, provides access to radial highways (such as US 290 or SH 249), and would serve as a third loop around the Houston metropolitan area. The Segment F-1 study area is generally bounded by US 290/SH 6 to the west, SH 249 to the east, Farm-to-Market Road (FM) 1960 to the south, and the Harris/Montgomery County line to the north.

The current status of each segment of the Grand Parkway is shown in **Table 1**. Locations of these segments are illustrated in **Exhibit 3** of **Appendix A.**

TABLE 1
GRAND PARKWAY SEGMENTS: STATUS OF ENVIRONMENTAL DOCUMENTS

Segment	Proposed Location	Approx. Length (mi)	Counties	Status
A	SH 146 west to IH 45	6.5	Galveston	Corridor Feasibility Study initiated (fall 2008)
B	IH 45 west to SH 288	28.2	Galveston, Brazoria	Draft EIS (DEIS) anticipated publication in summer 2009
C	SH 288 west to US 59	26.9	Brazoria, Fort Bend	FEIS anticipated publication in summer 2009
D	US 59 north to IH 10	18.2	Fort Bend, Harris	Re-evaluation for tolling approved in September 2008
E	IH 10 north to US 290	15.2	Harris	ROD issued in June 2008
F-1	US 290 east to SH 249	11.9	Harris	ROD issued in November 2008
F-2	SH 249 east to IH 45	12.1	Harris	FEIS published in August 2008
G	IH 45 east to US 59	13.6	Harris, Montgomery	FEIS published in February 2009
H & I-1	US 59 south to US 90/ US 90 south to IH 10	37.3	Montgomery, Harris, Liberty, Chambers	DEIS anticipated publication in fall 2009
I-2	IH 10 south to SH 146	14.5	Chambers, Harris	Re-evaluation for IH 10 to Fisher Road approved in December 2007 and Re-evaluation for Fisher Road to SH 146 in progress

Note: Bold/Shaded text indicates the segment included in this study
Source: GPA, 2009

In August 1993, TxDOT and FHWA filed a Notice of Intent (NOI) to prepare an Environmental Impact Statement (EIS) for Segment F-1 of the Grand Parkway. (An NOI is published in the Federal Register to notify the public that an agency is preparing an EIS.) Formal public scoping meetings were held in September 1993 and February 2000.

Following the publication of Segment F-1's DEIS in October 2003, a Public Hearing was held on November 18, 2003. The Public Hearing consisted of an exhibit viewing session, a formal presentation, and a public commenting session. After careful consideration of comments received on the DEIS and updates to the environmental resource mapping, inventory of potential direct impacts, and indirect and cumulative effects assessment, a Preferred Alternative Alignment was selected (see FEIS, Volume II, Section 6 [Agency and Public Coordination] for a detailed discussion of agency and public involvement). The selection of the Preferred Alternative Alignment is in compliance with regulations issued by the Council on Environmental Quality (CEQ) (40 CFR 1500-1508), FHWA (23 CFR 771), and the state of Texas (43 TAC Section 2.43), as well as in accord with the FHWA Technical Advisory T 6640.8A.

Following publication of the FEIS, the public comment period was open from June 6, 2008 to July 10, 2008. During this time, the public was invited to submit comments in written format or by e-mail. After careful consideration of comments received on the FEIS a Selected Alternative was determined. The Selected Alternative, as set forth in the ROD, best serves the need for and purpose of this project.

The April 2003 Texas Transportation Commission Minute Order 109226 (**Appendix B**) states, "The completion of the Grand Parkway is essential and urgent, as construction of the projects would alleviate congestion and improve traffic flow in the Houston metropolitan area and the surrounding region..." and "The commission has determined that constructing and operating the Grand Parkway as a toll facility is the most efficient and expeditious means of ensuring its development, and encourages the development of partnerships and the employment of innovative methods for its financing and construction." The Houston-Galveston Area Council's (H-GAC) 2025 Regional Transportation Plan (RTP) identifies the addition of tolled facilities, including the Grand Parkway, as necessary to address current congestion and future growth in the Houston region (H-GAC, 2005). H-GAC has been designated by the state of Texas as the metropolitan planning organization (MPO) charged with coordinating transportation planning for the eight-county area around Houston, including Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller Counties.

3.0 STATUS OF RIGHT-OF-WAY ACQUISITION AND CONSTRUCTION SCHEDULE

Maps and surveys for ROW acquisition are being prepared. None of the ROW for the project has been acquired. Construction activities for this project are expected to commence in late 2011. It is anticipated that all ROW will be acquired by start of construction.

4.0 PUBLIC INVOLVEMENT SINCE FHWA ROD

Since issuance of the ROD on November 20, 2008, a continuous effort for public involvement has occurred. The GPA continues to respond to questions from the public and address all appropriate comments regarding the Grand Parkway. Additionally, the H-GAC performed their quarterly outreach effort to engage the public in regional transportation issues. The 2009 first quarter public meetings were held on March 25-27, 2009 to discuss various topics, including updates on Grand Parkway Segments E, F-1, F-2, and G.

5.0 CHANGES TO PROJECT SINCE FHWA ROD

The issuance of the ROD approved the design of a four-lane, controlled access toll road with intermittent frontage roads within a 400-foot ROW. This section describes the project design change that is proposed for Segment F-1. The location of the design change is outlined on **Exhibit 1**, in **Appendix A**. This design feature requires no additional ROW or easements from that studied in the ROD.

Future Mason Road Grade Separation: In response to development in the study area, the proposed design change is to construct a grade separation at future Mason Road. The design change for the grade separation at future Mason Road would be located between Schiel Road and Muschke Road as depicted on **Exhibit 1** in **Appendix A**. This proposed design change would cost approximately an additional $3.5 million to construct the grade separation. This grade separation is the only design change proposed since issuance of the ROD on November 20, 2008. There would be no new access provided for future Mason Road. The remainder of the Segment F-1 project, as discussed in the ROD, remains unchanged. Any additional design changes will be evaluated through the environmental process and must be approved with appropriate documentation of the National Environmental Policy Act of 1969 (NEPA) and the MPO transportation planning process.

During the original schematic design of the facility, it was determined that Little Cypress Creek would serve as a barrier to the future extension of the Mason Road thoroughfare. If the extension of Mason Road to the Grand Parkway were to occur, it could be designed to overpass the Grand Parkway with no access provided to the Grand Parkway. During the development of the schematic design, the Lakes of Fairhaven subdivision was developed and a Mason Road bridge over little Cypress Creek was constructed as a part of the subdivision development. It was determined that the extension of Mason Road over Little Cypress Creek increased the likelihood of the further extension of Mason Road to the Grand Parkway. In order to better accommodate this likely future extension of Mason Road to the Grand Parkway, the decision was made to add a Grand Parkway mainlane overpass at Mason Road with no access provided to the Grand Parkway.

6.0 EVALUATION OF SCHEMATIC DESIGN CHANGE

This Re-evaluation examines all the environmental issues that were originally investigated and reported in the ROD. This examination has determined that the Re-evaluation design change would result in no substantive change in project impacts to the natural resources and environmental issues shown in **Table 2**, for the primary reasons noted in the "Explanation" column.

TABLE 2
RESOURCES/ISSUES DETERMINED TO HAVE NO SUBSTANTIVE CHANGE DUE TO DESIGN CHANGE

Resource/Environmental Issue Studied in the ROD	Explanation
Land Use and Transportation Planning	• The Re-evaluation design change would be consistent with state and local government plans and policies on land use and growth that are relevant within the project area. With regard to regional and community growth, the analysis as reported in the ROD remains valid.
Indirect and Cumulative Impacts	• The Re-evaluation design change extends no farther than the ROW reported in the ROD. Consequently, the previous review of indirect and cumulative impacts would apply to the design change. • The alternatives evaluation process was based on the philosophy of avoidance first, minimization second, and mitigation last. All project-specific commitments and conditions of approval, including resource agency permitting, compliance, and monitoring requirements are stated in the FEIS and the ROD.
Geology, Soils, and Farmland	• The Re-evaluation design change extends no farther than the ROW studied in the ROD. Consequently, the previous review of geology, soils, and farmland would apply to the design change. With regard to prime farmland soils and statewide and local important farmland soils, the analysis as reported in the ROD remains valid.
Social Characteristics	• The Re-evaluation design change would not relocate, displace, or impact public facilities and services. With regard to public facilities and services, the analysis as reported in the ROD remains valid. • The Re-evaluation design change would not affect, separate, or isolate any distinct neighborhoods, ethnic group, or other specific group. With regard to community cohesion, the analysis as reported in the ROD remains valid. • The Re-evaluation design change would not involve any populations of racial minorities, low-income, or limited English proficiency populations that would be in addition to the populations previously reported in the ROD. With regard to EJ, the analysis as reported in the ROD remains valid and in compliance with EO 12898 on EJ and Title VI of the Civil Rights Act of 1964, 42 U.S.C. § 2000d et seq.

TABLE 2 (CONT.)
RESOURCES/ISSUES DETERMINED TO HAVE NO SUBSTANTIVE CHANGE DUE TO DESIGN CHANGE

Resource/Environmental Issue Studied in the ROD	Explanation
Economics	• The Re-evaluation design change would not alter the number or types of employers in the area, nor would the design change have an appreciable effect on the labor force in the area. There is no additional ROW required for the design change, and therefore it does not involve any new Census tracts or neighborhoods. With regard to the economic impacts, the demographic data, analysis, and conclusion reported, the analysis as reported in the ROD remains valid.
Bicyclists and Pedestrians	• The Re-evaluation design change would not relocate, displace, or impact any bicyclists or pedestrian facilities. With regard to bicyclist and pedestrian facilities, the analysis as reported in the ROD remains valid.
Air Quality	• The Re-evaluation design change would not add new capacity to the roadway; thus modeled air quality impact levels would be the same as reported in the ROD. With regard to air quality, the analysis as reported in the ROD remains valid.
Noise Analysis	• All land use areas in the vicinity of the Re-evaluation design change are currently undeveloped; therefore, the proposed design change would not result in any noise impacts. • On the date of approval of this Re-evaluation, FHWA, TxDOT, or any entity that takes responsibility of the construction of Segment F-1 are no longer responsible for providing noise abatement for new development adjacent to the project.
Water Quality	• The Re-evaluation design change would not trigger any new water quality erosion or sediment control measures. • The Re-evaluation design change does not involve any hydrologic features that were not reported in the ROD and would not introduce any new impacts to them beyond what was reported in the ROD. The best management practices noted in the ROD would be incorporated into final design.
Permits	• The Re-evaluation design change would not trigger any new permits for the Grand Parkway Segment F-1. The appropriate Section 404 permit and Texas Pollutant Discharge Elimination System (TPDES) permit will be obtained from the U.S. Army Corps of Engineers (USACE) and the Texas Commission on Environmental Quality (TCEQ), respectively, prior to construction. With regard to required permits, the analysis as reported in the ROD remains valid.
Wetlands	• The Re-evaluation design change does not involve any wetland features that were not examined in the ROD and would not introduce any new impacts to them beyond what was reported in the ROD. With regard to wetland impacts, the analysis as reported in the ROD remains valid.
Wildlife	• The Re-evaluation design change extends no farther than the ROW studied in the ROD. With regard to wildlife impacts, the analysis as reported in the ROD remains valid.

TABLE 2 (CONT.)
RESOURCES/ISSUES DETERMINED TO HAVE NO SUBSTANTIVE CHANGE DUE TO DESIGN CHANGE

Resource/Environmental Issue Studied in the ROD	Explanation
Waterbody Modifications and Floodplains	• The Re-evaluation design change extends no farther than the ROW studied in the ROD. Consequently, the previous review of waterbody modifications and floodplains would apply to the design change. With regard to waterbody modifications and floodplains, the analysis as reported in the ROD remains valid.
Wild and Scenic Rivers	• The Re-evaluation design change extends no farther than the ROW studied in the ROD. The project is not situated in the vicinity of any wild and scenic rivers. With regard to wild and scenic rivers, the analysis as reported in the ROD remains valid.
Coastal Zone Management	• The Re-evaluation design change extends no farther than the ROW studied in the ROD. The project area is not within the Coastal Management Program boundary. With regard to coastal zone management, the analysis as reported in the ROD remains valid.
Essential Fish Habitat (EFH)	• The Re-evaluation design change extends no farther than the ROW studied in the ROD. The project does not intersect tidally influenced waters and would have no impact to EFH. With regard to EFH, the analysis as reported in the ROD remains valid.
Threatened and Endangered Species	• The Re-evaluation design change occurs within the same ROW and affects the same types of habitat that were previously reported in the ROD. • This examination has determined that the Re-evaluation design changes would result in no substantive change in project impacts. The Re-evaluation design change extends no farther than the ROW reported in the ROD; consequently, the effect call under the Endangered Species Act (ESA) in the ROD would apply to the design change.
Cultural Resources	• The Re-evaluation design change extends no farther than the ROW as reported in the ROD. Consequently, the previous review of cultural resources would apply to the design change. • *Standing Historic Properties* - The proposed design change will not directly affect any of the properties determined eligible to the National Register in previous coordination with THC. The proposed overpass does not represent a significant design change and, as previously coordinated, the selected alignment remains at a great distance from the eligible properties. Furthermore, the proposed design change poses no indirect or cumulative effects to historic properties.
Hazardous Materials	• The Re-evaluation design change extends no farther than the ROW reported in the ROD. Consequently, the previous review of regulatory agency records, aerial photographs, and field reconnaissance would apply to the design change. With regard to hazardous waste/substances, the analysis as reported in the ROD remains valid.
Visual and Aesthetic Qualities	• There are two groups potentially affected visually by the proposed action: those who use the roadway for travel, and those who live and work in proximity to the roadway. Highly scenic, sensitive views are generally not present within Segment F-1. The Re-evaluation design change would not alter the aesthetic characteristics of the roadway or surrounding area beyond what was described in the ROD. With regard to aesthetic considerations, the analysis as reported in the ROD remains valid.

7.0 UPDATE REVIEW AND CONTINUING COMMITMENTS SINCE ISSUANCE OF ROD

This Re-evaluation examines all the environmental issues that were originally investigated and reported in the ROD. This examination has determined that the Re-evaluation would result in no substantive change in impacts to the affected environment of the natural resources and environmental issues shown in **Table 3**, for the primary reasons noted in the "Explanation" column. The resources and issues discussed in the ROD that are not noted in **Table 3** are discussed in detail in **Sections 7.1** through **7.5** of this Re-evaluation report, which includes Indirect and Cumulative Impacts, Water Quality, Threatened and Endangered Species, and Cultural Resources.

TABLE 3
RESOURCES/ISSUES DETERMINED TO HAVE NO SUBSTANTIVE CHANGE TO AFFECTED ENVIRONMENT

Resource/Environmental Issue Studied in the ROD	Explanation
Land Use and Transportation Planning	• After additional review of the affected environment for land use and transportation planning, there have been minor changes that have occurred in the project area. These minor changes include new homes built in developments previously discussed in the FEIS and ROD as well as continued progress on transportation projects that were discussed in the FEIS and the ROD. There is no additional ROW required since the issuance of the ROD. There are no developments that have not been previously recognized in the FEIS or ROD. With regard to regional and community growth, the analysis as reported in the ROD remains valid.
Geology, Soils, and Farmland	• After additional review of the affected environment for geology, soils, and farmland, there is no additional ROW required since issuance of the ROD. Consequently, there are no new effects to geology, soils, and farmland. With regard to prime farmland soils and statewide and local important farmland soils, the analysis as reported in the ROD remains valid.
Social Characteristics	• After additional review of the affected environment for social characteristics, there are no changes to relocations, displacements, or impacts to public facilities and services. With regard to public facilities and services, the analysis as reported in the ROD remains valid. • After additional review of the affected environment for social characteristics, there are no changes to the project area that would affect, separate, or isolate any distinct neighborhoods, ethnic group, or other specific group. With regard to community cohesion, the analysis as reported in the ROD remains valid. • After additional review of the affected environment for social characteristics, there are no changes to the project area that would involve any populations of racial minorities, low-income, or limited English proficiency populations that would be in addition to the populations previously reported in the ROD. With regard to EJ, the ROD analysis remains valid and in compliance with EO 12898 on EJ and Title VI of the Civil Rights Act of 1964, 42 U.S.C. § 2000d et seq.

TABLE 3 (CONT.)
RESOURCES/ISSUES DETERMINED TO HAVE NO SUBSTANTIVE CHANGE TO AFFECTED ENVIRONMENT

Resource/Environmental Issue Studied in the ROD	Explanation
Economics	• After additional review of the affected environment for economics there is no change in the number or types of employers in the area, nor any new appreciable effect on the labor force in the area. There is no additional ROW required since issuance of the ROD, and therefore the ROW does not involve any new Census tracts or neighborhoods. With regard to the affected environment for economic impacts, the demographic data, analysis, and conclusion reported, the analysis as reported in the ROD remains valid.
Bicyclists and Pedestrians	• After additional review of the affected environment for bicyclists and pedestrians, there is no new effect regarding relocating, displacing, or impacting any bicyclists or pedestrian facilities. With regard to the affected environment for bicyclist and pedestrian facilities, the analysis as reported in the ROD remains valid.
Air Quality	• After additional review of the affected environment for air quality, there is no new added capacity to the roadway; thus modeled air quality impact levels would be the same as reported in the ROD. With regard to the affected environment for air quality, the analysis as reported in the ROD remains valid. • Carbon dioxide (CO_2) is a naturally occurring greenhouse gas and is not currently regulated by the U.S. Environmental Protection Agency (EPA). Greenhouse gases may contribute to global warming. The Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act was signed by the EPA on April 17, 2009. On April 24, 2009, the proposed rule was published in the Federal Register under Docket ID No. EPA-HQ-OAR-2009-0171. The public comment period is open until June 23, 2009, 60 days following publication in the Federal Register.
Noise Analysis	• After additional review of the affected environment for noise impacts, there are not changes to the overall project area that would alter the results of the noise analysis reported in the ROD; therefore, the noise analysis remains valid. • On the date of approval of this Re-evaluation, FHWA, TxDOT, or any entity that takes responsibility of the construction of Segment F-1 are no longer responsible for providing noise abatement for new development adjacent to the project.
Permits	• After additional review of the affected environment for permits, there are no new permits for the Grand Parkway Segment F-1. The appropriate Section 404 permit and TPDES permit will be obtained from the USACE and the TCEQ, respectively, prior to construction. With regard to the affected environment for required permits, the analysis as reported in the ROD remains valid.

TABLE 3 (CONT.)
RESOURCES/ISSUES DETERMINED TO HAVE NO SUBSTANTIVE CHANGE TO AFFECTED ENVIRONMENT

Resource/Environmental Issue Studied in the ROD	Explanation
Wetlands	• A Section 404 Individual Permit application and mitigation plan will be submitted to the USACE. Every effort has been made to avoid and minimize wetland impacts, both jurisdictional and non-jurisdictional, to the extent practicable during the planning process. This effort will continue through construction of the Grand Parkway Segment F-1 project. Impacts that cannot be avoided or further minimized will be mitigated per the project mitigation plan as approved by the USACE. During the Section 404 Individual Permit process and prior to USACE approval, the Section 404 permit application and mitigation plan will be made available for public review and comment through the USACE public notice process. With regard to wetland impacts, the analysis as reported in the ROD remains valid.
Waterbody Modifications and Floodplains	• All alternative alignments considered for this project would affect floodways and floodplains. While the Selected Alternative as presented in the ROD will cross 121.2 acres of regulatory floodway and 81.9 acres of 100-year floodplain, it provided the best impact balance of natural, cultural, and social resources for the entire project. Final design will include further consideration of bridging floodplains and final drainage and mitigation analyses, and all feasible and practicable bridging of 100-year floodplains will be further evaluated during final design. After additional review of the affected environment for waterbody modifications and floodplains, there are no changes to the project area that would change the analysis for the only practicable alternative finding as presented in Section L.2 of the ROD. With regard to waterbody modification and floodplains, the ROD analysis remains valid.
Wildlife	• After additional review of the affected environment for wildlife, there is no additional ROW required since issuance of the ROD. Consequently, there are no new effects to wildlife. With regard to the affected environment for wildlife, the ROD analysis remains valid.
Wild and Scenic Rivers	• After additional review of the affected environment for wild and scenic rivers, there is no additional ROW required since issuance of the ROD. Consequently, there are no new effects to wild and scenic rivers. With regard to the affected environment for wild and scenic rivers, the ROD analysis remains valid.
Coastal Zone Management	• After additional review of the affected environment for coastal zone management, there is no additional ROW required since issuance of the ROD. Consequently, there are no new effects to coastal zone management. With regard to the affected environment for coastal zone management, the ROD analysis remains valid.
Essential Fish Habitat (EFH)	• After additional review of the affected environment for EFH, there is no additional ROW required since issuance of the ROD. Consequently, there are no new effects to EFH. With regard to the affected environment for EFH, the ROD analysis remains valid.
Hazardous Materials	• After additional review of the affected environment for hazardous waste/substances, there is no additional ROW required since issuance of the ROD. Consequently, there are no new effects to hazardous waste/substances. With regard to hazardous waste/substances, the ROD analysis remains valid.

TABLE 3 (CONT.)
RESOURCES/ISSUES DETERMINED TO HAVE NO SUBSTANTIVE CHANGE TO AFFECTED ENVIRONMENT

Resource/Environmental Issue Studied in the ROD	Explanation
Visual and Aesthetic Qualities	• There are two groups potentially affected visually by the proposed action: those who use the roadway for travel, and those who live and work in proximity to the roadway. Highly scenic, sensitive views are generally not present within Segment F-1. After additional review of the affected environment for visual and aesthetic qualities there is no change in the aesthetic characteristics of the roadway or surrounding area beyond what was described in the ROD. With regard to aesthetic considerations, the ROD analysis remains valid.

7.1 Indirect and Cumulative Impacts

This Re-evaluation does not involve any new resource features that were not examined in the ROD and would not introduce any new impacts to them beyond what was reported in the ROD. The Grand Parkway Area of Influence (AOI) is undergoing rapid population and employment growth and is anticipated to continue through the year 2025 and beyond regardless of when or if the Grand Parkway is constructed. However, the Segment F-1 Selected Alternative, as presented in the ROD, will compliment and reinforce the development pattern and effects. The Grand Parkway, combined with other local/regional development efforts, would serve to accommodate growth and development, either present or planned. In addition, a number of regulatory mechanisms are in place to offset or minimize the adverse effects of social and economic growth. Efforts have been made to avoid and minimize project effects to all resources at both the corridor and alignment development phases of the project, and measures would be implemented to mitigate the loss of resources where practicable.

The alternative evaluation process was based on the philosophy of avoidance first, minimization second, and mitigation last. All project-specific commitments and conditions of approval, including resource agency permitting, compliance, and monitoring requirements are stated in the FEIS and the ROD. With regard to the affected environment for Indirect and Cumulative Effects, the ROD analysis remains valid.

7.2 Water Quality

The TCEQ Permanent Rules Chapter 307, Texas Surface Water Quality Standards (TSWQS) Subsections 307.1 – 307.10, dated August 17, 2000, presents surface water quality standards that apply to all surface waters in the state. The major surface waters of the state are classified in the TSWQS as "segments" for the purposes of water quality management and designation of site-specific standards. This examination has determined that no substantive change in project impacts to the water quality concerns listed in **Table 4** have occurred since the issuance of the ROD. The resources and issues discussed in the ROD have been updated and are discussed in detail in the following section.

There are two streams within the Segment F-1 project area: Little Cypress Creek and Willow Creek. Other streams in the project area include unnamed tributaries, most of which are manmade drainage ditches. All of the streams are located within the San Jacinto River Basin. The San Jacinto River Basin has a drainage area of over 3,400 square miles. The State of Texas Water Quality Inventory states that the water quality for the streams, rivers, and bayous within the San Jacinto River Basin varies widely depending on the land use within the sub-basins (TCEQ, 1998).

Chapter 26.023 of the Texas Water Code gives authority to the TCEQ to establish water quality standards for all state waters. Each designated stream or river segment has specific desired water uses and numerical criteria developed by the TCEQ. The 2008 303(d) (TCEQ, 2008), the most recent data available, indicates water quality concerns for both of the segments that traverse the project area (Little Cypress Creek is Segment 1009E and Willow Creeks is Segment 1008H), and other segments that are adjacent to the project area (a portion of Cypress Creek segment which is Segment 1009 and Faulkey Gully which is Segment 1009C). Water quality concerns for above-mentioned stream segments that are summarized in **Table 4**.

TABLE 4
SUMMARY OF WATER QUALITY CONCERNS FOR SEGMENT F-1

TSWQS Segment	Streams	Water Quality Concerns
1009E	Little Cypress Creek	This segment was identified as impaired on the 2008 303(d) List due to: Bacteria levels in the following areas: From the confluence with Cypress Creek upstream to Highway 290A. These levels are the result of both point and non-point sources. A Total Maximum Daily Load (TMDL) is underway, scheduled, or will be scheduled.
1008H	Willow Creek	This segment was identified as impaired on the 2008 303(d) List due to: Bacteria levels in the following areas: From 0.3 miles north of Juergen Road to the confluence with Spring Creek. These levels are the result of both point and non-point sources. A TMDL is underway, scheduled, or will be scheduled.

TABLE 4 (CONT.)
SUMMARY OF WATER QUALITY CONCERNS FOR SEGMENT F-1

TSWQS Segment	Streams	Water Quality Concerns
1009	Cypress Creek	This segment was identified as impaired on the 2008 303(d) List due to: Bacteria levels in the following areas: IH 45 to confluence with Spring Creek; SH 249 to IH 45; US 290 to SH 249; and the upper portion of the segment to downstream of US 290. These levels are the result of both point and non-point sources. A TMDL is underway, scheduled, or will be scheduled.
1009C	Faulkey Gully	This segment was identified as impaired on the 2008 303(d) List due to: Bacteria levels in the following areas: Perennial stream from its confluence with cypress Creek upstream 3.2 km, which is approximately 1.0 km upstream of Louetta Road. These levels are the result of both point and non-point sources. Additional information will be collected before a TMDL is scheduled.

Source: TCEQ, 2008 303(d)

As presented in the ROD, the project would affect more than five acres, and TxDOT would be required to comply with the TCEQ TPDES General Permit for Construction Activity, which would be accomplished by developing a Storm Water Pollution Prevention Plan (SWP3), filing an NOI prior to construction, and complying with the SWP3 throughout construction activities.

The Re-evaluation does not involve any hydrologic features that were not examined in the ROD and would not introduce any new impacts to them beyond what was reported in the ROD. The best management practices noted in the ROD would be incorporated into final design. With regard to the affected environment for water quality, the ROD analysis remains valid.

7.3 Threatened and Endangered Species

Analysis of potential effects to threatened and endangered species under the ESA is a continuous process. Information in this section provides an update to information presented in the FEIS and the ROD. Both the U.S. Fish and Wildlife Service (USFWS) and the Texas Parks and Wildlife Department (TPWD) maintain species lists for Harris County. As of May 13, 2009, the USFWS online list for Harris County listed only the Texas prairie dawn as endangered and the bald eagle as delisted within the five year post-delisting monitoring period. On May 13, 2009, a review of TPWD's online Annotated County List of Rare Species for Harris County was also conducted, and the status of the state listed species is reflected in **Table 5**. Additionally, a review of TPWD's Natural Diversity Database (NDD) was conducted in March 2009 for any documented occurrences of threatened or endangered species that may occur within or adjacent to the ROW, and none were identified. The listed status of each threatened and endangered species for Harris County is presented in **Table 5**.

TABLE 5
STATE AND FEDERAL THREATENED OR ENDANGERED SPECIES OF HARRIS COUNTY, TEXAS

Common Name	Scientific Name	State Status	Federal Status	Habitat Description	Habitat Present
Amphibians					
Houston toad	*Bufo houstonensis*	E	E*	Sandy soil, breeds in ephemeral pools	No
Birds					
American Peregrine falcon	*Falco peregrinus anatum*	E	DM*	Potential migrant	Migrant
Arctic Peregrine falcon	*Falco peregrinus tundrius*	T	DM*	Potential migrant	Migrant
Bald eagle	*Haliaeetus leucocephalus*	T	DM*	Near rivers and large lakes, in tall trees	Yes
Brown pelican	*Pelecanus occidentalis*	E	E*, PDL	Island near coastal areas	No
Red-cockaded woodpecker	*Picoides borealis*	E	E*	Nest in 60+ year pine, forages in 30+ pine	No
White-faced ibis	*Plegadis chihi*	T	--	Freshwater marshes, sloughs and irrigated rice fields, but some brackish or salt marshes	Yes
White-tailed hawk	*Buteo albicaudatus*	T	--	Coastal prairies and inland prairies and mesquite-oak savannahs	Yes
Whooping crane	*Grus americana*	E	E*	Potential migrant; winters in coastal marshes of Aransas, Calhoun, and Refugio counties	Yes
Wood stork	*Mycteria americana*	T	--	Prairie ponds and flooded pastures, ditches or other shallow standing water	Yes
Fishes					
Creek chubsucker	*Erimyzon oblongus*	T	--	Tributaries of the Red, Sabine, Neches, Trinity, and San Jacinto rivers; variety of small rivers and creeks, prefers headwaters	Yes
Mammals					
Louisiana black bear	*Ursus americanus luteolus*	T	T*	Possible as transient; bottomland hardwoods; large, inaccessible forested areas	No

TABLE 5 (CONT.)
STATE AND FEDERAL THREATENED OR ENDANGERED SPECIES OF HARRIS COUNTY, TEXAS

Common Name	Scientific Name	State Status	Federal Status	Habitat Description	Habitat Present
Mammals					
Rafinesque's big-eared bat	*Corynorhinus rafinesquii*	T	--	Cavity trees in bottomland hardwoods, concrete culverts, abandoned buildings	No
Red wolf	*Canis rufus*	E	E*	Extirpated; formerly known throughout eastern half of Texas in brushy, forested areas and coastal prairies	No
Reptiles					
Alligator snapping turtle	*Macroclemys temminckii*	T	--	Deep water of rivers, lakes, oxbows and canals; usually in water with mud bottom and abundant aquatic vegetation	Yes
Green sea turtle	*Chelonia mydas*	T	T*	Gulf and bay system	No
Leatherback sea turtle	*Dermochelys coriacea*	E	E*	Gulf and bay system	No
Loggerhead sea turtle	*Caretta caretta*	T	T*	Gulf and bay system	No
Smooth green snake	*Liochlorophis vernalis*	T	--	Gulf Coastal Plain, mesic coastal shortgrass prairie vegetation; prefers dense vegetation	Yes
Texas horned lizard	*Phrynosoma cornutum*	T	--	Open, semi-arid regions with sparse vegetation, including grass, cactus, scattered brush or scrubby trees; sandy to rocky soils	No
Timber/Canebrake rattlesnake	*Crotalus horridus*	T	--	Swamps, floodplains, upland pine and deciduous woodlands, riparian zones, and abandoned farmland; prefers dense groundcover	Yes
Vascular Plants					
Texas prairie dawn	*Hymenoxys texana*	E	E	Poorly drained depressions or base of mima mounds in open grasslands, or mostly undeveloped areas on slightly saline soils	Yes

Notes: * These species are listed by the USFWS; however, they are not listed to occur within this county by the Clear Lake office of the USFWS (2009).

-- These species occur on the State listing of threatened or endangered species; however, they are not federally listed at this time by the USFWS (2009).

E = Endangered; T = Threatened; C = Candidate Species; DM = Delisted taxon, recovered, being monitored first five years; PDL = proposed delisting

Source: USFWS 2009

State and Federally Listed Threatened and Endangered Species

This examination has determined that no substantive change in project impacts to the species listed in **Table 5** have occurred since the issuance of the ROD. The resources and issues discussed in the ROD have been updated and are discussed in detail in the following section. With regard to threatened and endangered species, the ROD analysis of may affect but not likely to adversely affect the Texas prairie dawn remains valid.

Several threatened, endangered, or rare bird species may potentially occur within the Segment F-1 project area at various times throughout the year. None of the state or federally listed species has any known documented nest sites within the Segment F-1 project area (TPWD, 2009). Listed bird species would likely occur within the Segment F-1 project area to forage, roost, or migrate through the region. Based on conversations with TPWD staff during planning meetings, a bald eagle nest is located approximately 5 miles to the north of Segment F-1; however, the project is not likely to impact this nest location. During consultations with the TPWD in April 2006, TPWD indicated that no known eagles were presently nesting in the proposed project area. . Direct mortality impacts are not anticipated to any threatened, endangered, or rare bird species.

Adverse impacts to other state-listed species in **Table 5** (timber rattlesnake, alligator snapping turtle, smooth green snake, white-tailed hawk, wood stork and creek chubsucker) are not expected to occur due to the relative lack of recorded occurrences within the Segment F-1 project area (TPWD, 2006). Additionally, multiple field surveys within the project ROW did not indicate the presence of state-listed species. Water quality data (i.e., impaired stream segment with high *E. coli,* ammonia, total phosphorus and nitrates) within the Little Cypress Creek watershed and the physical characteristics (submerged debris and high water flow fluctuations) of Willow Creek do not suggest the presence of preferred habitat (i.e., clear headwaters, creeks, rivers, etc.) for the creek chubsucker within the Segment F-1 project area. Please refer to Section 3.8 (Water Quality) in the FEIS for additional information regarding water quality. During project development, TxDOT would design, use, and promote construction practices that minimize adverse effects to both regulated and unregulated wildlife habitat. Existing vegetation (especially native trees) would be avoided and preserved wherever practicable.

Bald Eagle

As of August 8, 2007, the bald eagle is no longer a federal threatened species; however, it will be monitored closely for at least the first five years after delisting (USFWS, 2007). The bald eagle is still afforded special protection under the Bald and Golden Eagle Protection Act.

Correspondence with the TPWD in 2001 and 2007 indicated that a bald eagle nest site is located approximately five miles north of the project area. Should bald eagles be noted foraging and/or roosting within the project area, steps would be taken to minimize potentially disruptive activities per the USFWS National Bald Eagle Management Guidelines (USFWS, 2007).

Texas Prairie Dawn

The Texas prairie dawn, a federal and state listed endangered plant, is an annual sunflower (Asteraceae) that ranges in height from 1.5 to seven inches. The bracts conceal the minute ray flowers; the yellow disk flowers are 0.1 to 0.2 inches long. Texas prairie dawn habitat consists of small, sparsely vegetated areas of fine-sandy saline soil. These sparsely vegetated areas commonly occur on the lower sloping portion of pimple (mima) mounds or on the level to slightly concave area around the mound's base. Prairie remnants are often characterized by this unusual microrelief topography (Smeins, 1994). The Texas prairie dawn blooms and fruits from mid-March to mid-April and senescence are usually complete by May (Poole and Riskind, 1987). There is a high potential for the Texas prairie dawn to occur within portions of the project area, especially within the Katy Prairie (Segments E and F-1).

Initial investigations of the Segment F-1 project area in 2000 and 2001, a review of the threatened and endangered species list, aerial photography, and the TPWD's NDD revealed that a known recorded population of Texas prairie dawn existed within one of the proposed alternative alignments for this section of the Grand Parkway. Ultimately the preferred alignment selected in the FEIS avoided this known population. In the FEIS, TxDOT concluded that the project is not likely to adversely affect any federally listed species, its habitat, or designated critical habitat due to lack of access to complete ground surveys on multiple properties within the Segment F-1 ROW for Texas prairie dawn. As a result, TxDOT committed in the FEIS to continue coordination with the USFWS and to perform additional surveys for Texas prairie dawn as access was granted to additional properties.

Additional field surveys were conducted by Dr. Larry Brown, plant taxonomist, on April 23, 2009 to determine the presence/absence of the Texas prairie dawn within and adjacent to the Segment F-1 ROW. A summary of Dr. Larry Brown's field surveys is provided in **Appendix B**. To date, access was granted to all but 10 parcels within the ROW. On the parcels that were surveyed, Texas prairie dawn was not found within or adjacent to the Segment F-1 ROW. The unsurveyed parcels were analyzed using high resolution aerial photography and soil survey maps for presence of suitable Texas prairie dawn habitat. Suitable habitat for Texas prairie dawn was identified on two of these 10 properties (PBS&J, 2009). These two properties will be surveyed for Texas prairie dawn either when access is granted by the landowner or when the property is purchased for the Grand Parkway Segment F-1 project. Additional surveys will be completed for the other eight unsurveyed properties within the ROW, where habitat was not identified, prior to construction to ensure populations or colonies are not present on these parcels. USFWS will receive a copy of the report for Segment F-1 prior to initiation of any construction activity. If the survey report indicates presence of Texas prairie dawn, consultation with USFWS will be reinitiated.

In accordance with 50 CFR 402.13, TxDOT concludes that the Grand Parkway Segment F-1 project may affect but is not likely to adversely affect the Texas prairie dawn. USFWS concurrence with this determination is provided in **Appendix B**. With regard to the affected environment for Threatened and Endangered Species, the ROD analysis remains valid.

7.4 Cultural Resources

The following sections detail both the results of investigations done in compliance with applicable cultural resource laws and regulations and the findings based on the investigations. The laws and regulations require the consideration of the impacts of the proposed project on cultural resources such as archeological sites and historic structures. TxDOT operates under several formal agreements that expedite its compliance with these laws and regulations.

Not all cultural resources are afforded equal treatment in the planning process under applicable cultural resources laws. Historic properties and State Archeological Landmarks are those objects, sites, and structures which have characteristics that require those resources to be given further consideration in the project planning process. Projects should avoid and minimize impacts to historic properties and SALs when possible. They should resolve the effects of impacts, usually through some mitigation measures, when avoidance is not possible.

To preview the results of investigations conducted for this proposed project, Surveys conducted for this project identified no historic properties that would be affected by the proposed undertaking. The following section will provide a formal account of the investigations and findings with appropriate citations to regulations and agreements. These results are discussed in more detail in the next sections, along with formal findings made in compliance with the applicable laws, regulations, and agreements.

7.5 Archeological Resources

A TxDOT archeologist evaluated the potential for the proposed undertaking to affect archeological historic properties (36 CFR 800.16(l)) or State Archeological Landmarks (13 TAC 26.12) in the area of potential effects (APE). The APE comprises the existing right-of-way (ROW) within the project limits [and any areas of new ROW or easements]. The APE extends to a maximum depth of 75 feet below the modern ground surface. Section 106 review and consultation proceeded in accordance with the First Amended Programmatic Agreement among the Federal Highway Administration, the Texas Department of Transportation, the Texas State Historic Preservation Officer, and the Advisory Council on Historic Preservation Regarding the Implementation of Transportation Undertakings (PA-TU), as well as the Memorandum of Understanding (MOU) between the Texas Historical Commission and TxDOT. The following documentation presents TxDOTs findings and explains the basis for those findings.

An intensive survey of the area of potential effects (APE) was performed by PBS&J under Texas Antiquities Permit No. 5275. This survey revealed no archeological deposits within the proposed undertaking's APE. However, only those parcels with right-of-entry (ROE) have been surveyed

TxDOT completed its review on 05/19/2009. Section 106 consultation with federally recognized Native American tribes with a demonstrated historic interest in the area was initiated on 04/30/2009. No objections or expressions of concern are anticipated within the comment period ending 06/07/2009.

Pursuant to Stipulation VI of the PA-TU, TxDOT finds that the APE does not contain archeological historic properties (36 CFR 800.16(l)), and thus the proposed undertaking would not affect archeological historic properties. The project area that has been surveyed does not merit further field investigations. However, the remainder of the archeological inventory is deferred until NEPA processing and property acquisition has been completed. Project planning can also proceed, in compliance with 13 TAC 26.20(2) and 43 TAC 2.24(f)(1)(C) of the MOU. If unanticipated archeological deposits are encountered during construction, work in the immediate area will cease, and TxDOT archeological staff will be contacted to initiate post-review discovery procedures under the provisions of the PA and MOU.

7.6 Regional Toll Analysis

As the MPO for the Houston Galveston region, the H-GAC is charged with enabling and creating a regional perspective for transportation and mobility. The 2035 RTP provides the major strategies that would accommodate forecasted growth and preserve mobility in the region. H-GAC prepared a planning-level assessment, *Regional Cumulative and Indirect Effects of Toll Facilities*[1] report, to determine how the 2035 RTP regional toll roadway network could indirectly or cumulatively affect socioeconomic and natural resources. Resources evaluated in this planning study included EJ populations (low-income and/or minority populations as defined in EO 12898[2]), air quality, water resources, vegetation, and land use. However, the majority of the H-GAC analysis focused on the potential impact of the regional toll roadway network on EJ populations in the region. For more information on the resources evaluated and for more detail on the EJ analysis, please see the H-GAC *Regional Cumulative and Indirect Effects of Toll Facilities* report.

7.6.1 Environmental Justice

Environmental Justice Findings

The H-GAC report estimated that for home based travel, EJ population trips that are candidate toll trips are benefited by the introduction of the new toll facilities in terms of both the toll and free path travel times. Equally important, EJ population trips that are not candidate toll users benefit by the introduction of the new toll facilities as the free path travel time Average Trip Length (ATL) in minutes is reduced between the No-Build and Build scenarios. As such, EJ populations experience an overall benefit under the Build Alternative for their home based travel.

According to the H-GAC report, the EJ zones are spread throughout the region and are generally clustered within Beltway 8, and are not in close proximity to the majority of future toll facilities when compared to the Non-EJ zones. Consequently, as the ATL of the EJ zones are less than the ATL of non-EJ zones, the EJ zones cannot derive as much travel time savings as the longer trips from Non-EJ zones. A significant amount of future transit improvements are targeted at EJ zones; the ATLs for the populations within those zones would generally improve due to increased access to improved transit facilities. In addition, the transit system has 485,000 daily passenger boardings and is expected to increase to nearly 725,000 by 2035. This increase will be attributed to:

• Expansion of transit services (increased bus and rail transit services),

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[1] HGAC, Regional Cumulative and Indirect Effects of Toll Facilities April 2009.
[2] Executive Order 12898: Federal Action to Address Environmental Justice in Minority Populations and Low-Income Populations.

• New transit modes (commuter rail transit and signature express bus service),

• Transit connectivity to multiple employment centers, and

• Coordination of transit services among regional public transportation providers.

An analysis was also conducted to determine the annual financial burden of utilizing the toll road system for Home Based Work (HBW) trips. The analysis assumed a 2035 toll rate per mile of 19.96 cents (current toll rate of 10 cents per mile with an annual escalation rate of 2.5 percent). In addition, the analysis assumed that an average HBW trip length is 23.30 miles and the single occupancy vehicle user makes 250 round-trips per year using the toll facility. Under this scenario, the annual cost would be approximately $2,325 per year. However, the accrual cost should be substantially less since the likelihood of a trip using only tolled facilities is diminutive.

Although EJ populations will see an increase in spending for toll facilities, the entire region will also see an increase in spending and usage as the toll and managed lane system expands. Both EJ and Non-EJ populations will benefit from future toll facilities. In fact, the 2035 RTP relies heavily on toll funding to finance a portion of future added capacity projects, both free and toll. Additionally, for both populations who choose to use non-toll options, the Build scenario for 2035 will provide a roadway network that will operate at better traffic conditions than the No-Build scenario and would provide an increased benefit for those users over the No-Build scenario.

Based on the previous discussion and analysis, the Build scenario for the 2035 RTP would not cause cumulative disproportionately high and adverse effects on EJ populations as per Executive Order 12898 regarding environmental justice.

7.6.2 Air Quality

The Clean Air Act Amendments of 1990 (CAAA) require that the Houston-Galveston region must demonstrate that the 2008 - 2011 Transportation Improvement Plan (TIP) and the long-range plan (2035 RTP) result in less volatile organic compounds (VOC) and nitrogen oxides (NOx) than established and approved by EPA for each analysis year. On September 30, 2008, the FHWA certified that the 2035 RTP and the 2008 – 2011 TIP conformed to the requirements of the SIP for the Houston-Galveston ozone nonattainment area. Based on a Level of Mobility analysis, the proposed 2035 RTP Regional Roadway Network would reduce the percentage of severely congested vehicle miles traveled in the morning peak period, from approximately 50 percent to less than 30 percent compared to the 2035 No-Build Scenario.

Air Quality Findings

The addition of tolled facilities and managed lanes into the existing regional roadway network would not have any cumulative impacts to air quality. Moreover, a tolled roadway network adds capacity to the regional roadway network, thus allowing a better flow of traffic and decreasing the amount of cars traveling at lower speeds or idling conditions. The improved traffic flow results in less fuel combustion and lower emissions including Mobile Source Air Toxins (MSATs), Carbon Monoxide (CO), and Ozone. The EPA's vehicle and fuel regulations, coupled with fleet turnover, are also expected to result in substantial reductions of on-road emissions, including MSATs, CO and ozone precursors.

7.6.3 Water Quality

The construction of the regional tolled roadway network would cross and impact the water bodies and could cause water quality impacts. The increase of impervious square footage from adding capacity to the regional roadway network increases the potential for non-point source pollution and the potential to cause further impairment to the region's waterways. TCEQ regulates water quality through SWP3, Municipal Separate Storm Sewer Systems (MS4), and Best Management Practices (BMPs). All construction of the regional tolled roadway network in the RTP would follow these water quality regulations which would aid in preventing further pollution to these impaired waters and to waters that are not already impaired. Additionally, any land use development that would occur from the construction of these facilities would be required to follow TCEQ's regulations for water quality through SWP3 and MS4.

Water Quality Findings

Although overall impacts cannot be avoided, the above mentioned mitigation techniques will ensure that the regional tolled roadway network would not have adverse cumulative impacts to water quality.

7.6.4 Vegetation

As growth and development are part of our region's future, it is not feasible that every environmental undeveloped parcel be preserved. However, it is feasible that the region identify and work to conserve those areas that are most ecologically sensitive. H-GAC identified areas that have sensitive environmental resources for special consideration in the transportation planning process. However, the identification is not intended to be used for project-level screening. The results are intended to be used for long-range planning purposes and screening to identify areas in which future transportation projects or development may potentially impact these sensitive resources. In addition, the identified environmental resources are areas in which mitigation efforts may be focused.

In some instances, disturbing natural resources may be unavoidable for regionally significant projects or projects located on facilities that are multiple-lane, limited access facilities, such as highways and toll roads. Due to their scale, regionally significant projects potentially have a larger impact on the environment than a local project and therefore were closely examined. Currently, projects within the 2035 RTP are individually subject to environment requirements but have no mechanism for cumulatively identifying or mitigating environmental impacts. At the project level, the TxDOT Houston District can mitigate for loss of vegetation with the Texas Parks and Wildlife Department, and wetlands mitigation would occur through the permitting process under the jurisdiction of the USACE. Locally, cities can also curb vegetation loss by implementing measures to protect vegetation areas.

Vegetation Findings

Impacts to vegetation will undoubtedly occur from the regional tolled roadway network. However, as these impacts are best evaluated and mitigated at the project level.

7.6.5 Land Use

The proposed 2035 regional roadway network is in support of the predicted land use changes and growth in the region. To meet the demand of the expansive growth and changes to land use from development, the aim of the 2035 regional roadway network is to supply the transportation portion of infrastructure requirements for the expanding growth and development. Current and future predicted available funds from the federal government for transportation alone will not be able meet the demands for the transportation infrastructure needed to support the predicted changes. Tolled roads and managed lanes are methods that the RTP employs to ensure the transportation demands from future growth is met when considering the limited transportation funds available.

Land Use Findings

The proposed 2035 regional tolled roadway network will affect land use within the MPO boundaries by creating land development and/or redevelopment opportunities. However, the regional tolled roadway network is only one factor in creating favorable land development conditions; other prerequisites for growth in the region include demand for new development, favorable local and regional economic conditions, adequate utilities, and supportive local land development policies. The proposed 2035 regional tolled roadway network may influence and facilitate the additional planned regional land use conversion, redevelopment, and growth.

7.6.6 Conclusion

The regional tolled roadway network would cause some impacts to natural and socio-economic resources. However, the regional tolled roadway network would have a beneficial impact on EJ populations and air quality in the Houston-Galveston area. Overall, with the 2035 build regional tolled roadway network in place, travel efficiencies in the region will benefit both EJ and non-EJ populations. The net benefit may be slightly greater for the non-EJ populations because the average trip length in these zones is greater than the average trip length from the EJ zones. In addition, the additional vehicle lane miles that the regional tolled roadway network provides enables traffic to flow more efficiently thereby reducing emission associated with cars traveling at lower speeds or idling conditions.

The regional priced facility system would cause minor impacts to some of the resources discussed in this analysis. Regional mitigation for some of these resources is addressed by the H-GAC. As part of 2035 RTP, H-GAC addressed two issues related to air quality and environmental justice populations. The Transportation Planning Process, at a regional level, provides ways to minimize any potential impacts that could occur. The priced facility projects would be included in the STIP/TIP and RTP, and the STIP/TIP and RTP would conform to the SIP. This assurance addresses each project is in compliance with the TIP/STIP and the RTP for air quality under the CAA and Environmental Justice under Title VI of the Civil Rights Act of 1964 and Executive Order 12898.

Finally, as required by NEPA, appropriate mitigation for direct impacts would occur at the project level. Because of these mitigation measures, the regional proposed tolled roadway network is not anticipated to have a substantial cumulative impact on the resources considered in this section.

8.0 CONCLUSION

The environmental documentation for this project has been reviewed, and it has been determined that there have been no significant changes to the assessed areas based upon the proposed design change and updates to commitments and permits. Continued coordination with USFWS has also occurred since issuance of the ROD.

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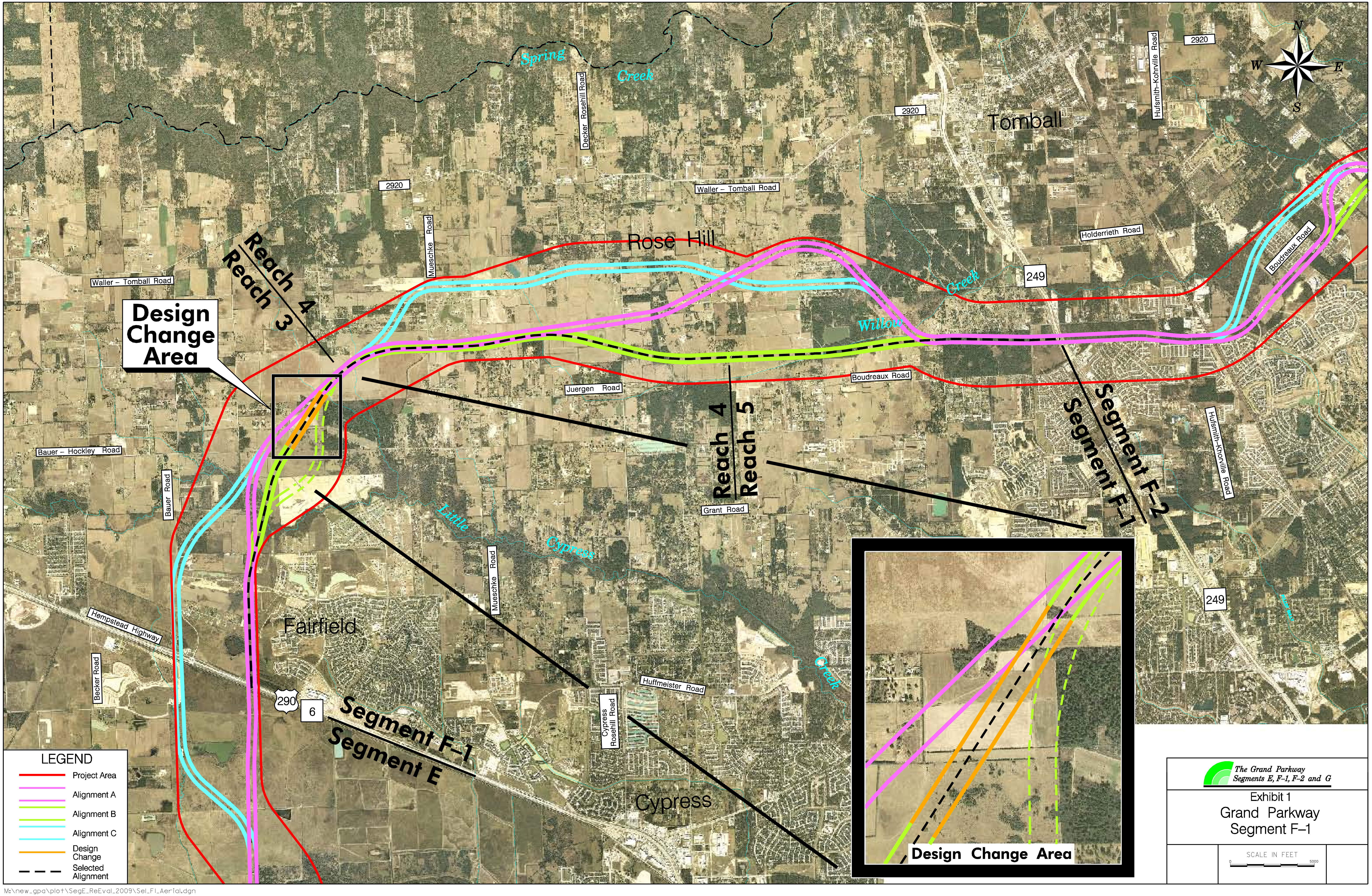
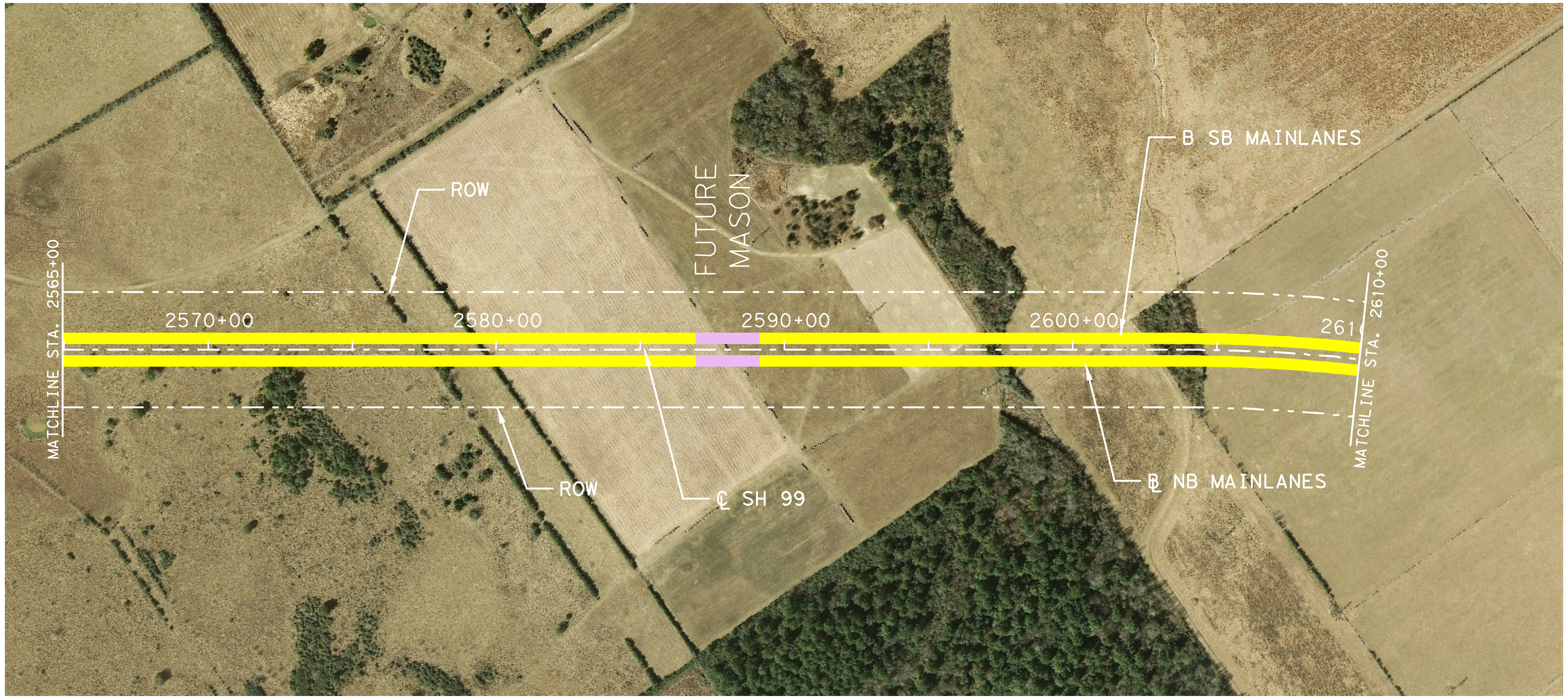
APPENDIX A

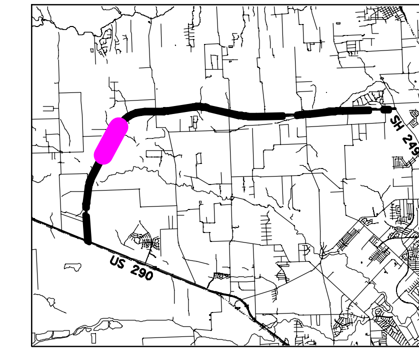
EXHIBITS



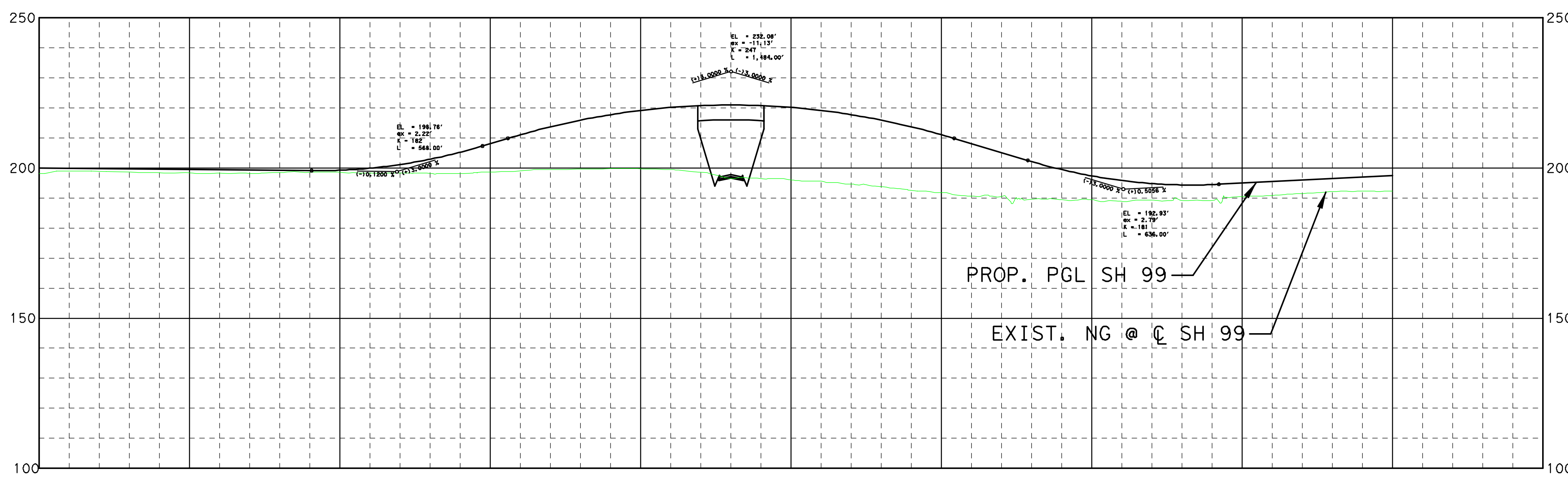
Spring
Creek
Tomball
2920
Hufsmith-Kohrville Road
Decker Rosehill Road
Waller - Tomball Road
Rose Hill
Mueschke Road
Holderrieth Road
Boudreaux Road
249
Willow
Creek
Reach 4
Reach 3
Design Change Area
Juergen Road
Reach 4
Reach 5
Segment F-2
Segment F-1
Bauer - Hockley Road
Bauer Road
Grant Road
Hufsmith-Kohrville Road
Little
Cypress
Creek
Hempstead Highway
Becker Road
Fairfield
Huffmeister Road
Cypress Rosehill Road
290
6
Segment F-1
Segment E
Cypress
Design Change Area
LEGEND
Project Area
Alignment A
Alignment B
Alignment C
Design Change
Selected Alignment
The Grand Parkway Segments E, F-1, F-2 and G
Exhibit 1
Grand Parkway
Segment F-1
SCALE IN FEET
N
S
E
W
M:\new_gpa\plot\SegE_ReEval_2009\Sel_F1_Aerial.dgn

PRELIMINARY - SUBJECT TO CHANGE





SCALE IN FEET
0 250 500



THESE DOCUMENTS ARE FOR INTERIM REVIEW AND NOT FOR CONSTRUCTION, BIDDING OR PERMIT PURPOSES.

RESPONSIBLE ENGINEER:
BROWN & GAY ENGINEERS, INC.
TBPE FIRM REGISTRATION NO. 1046
MATTHEW BRANNEN, P.E.
TEXAS REGISTRATION NO. 90868

DRAFT AS OF
15-May-09

Texas Department of Transportation

STATE HIGHWAY 99
GRAND PARKWAY-SEGMENT "F1"
FROM US 290 TO SH 249

PRELIMINARY SCHEMATIC LAYOUT
STA 2565+00 TO STA 2610+00

EXHIBIT 2

...\REEVAL*F1*SCHM*EXH2.dgn 15-May-09 9:39:07 AM Matt

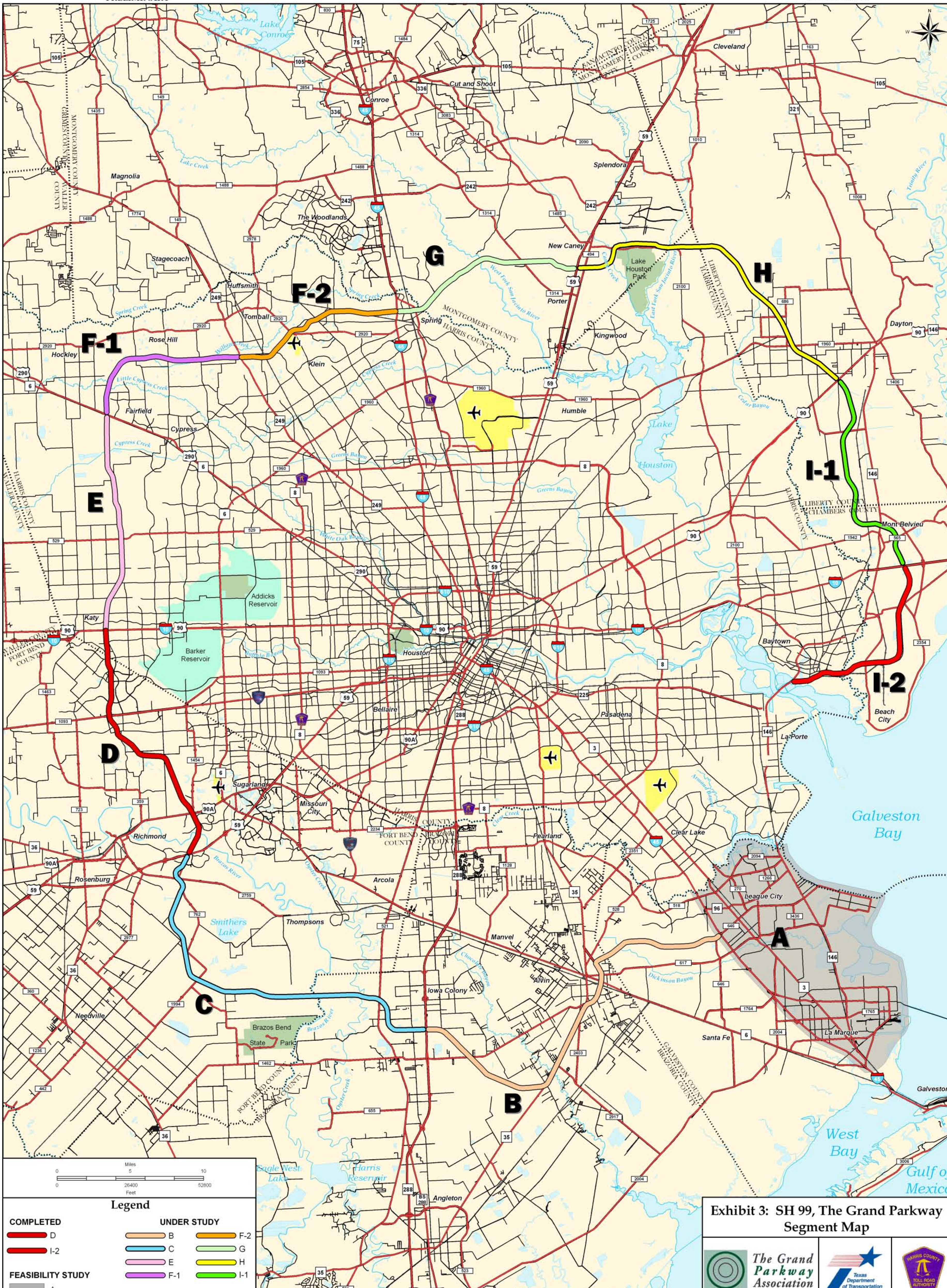


Exhibit 3: SH 99, The Grand Parkway Segment Map

APPENDIX B

LETTERS OF COORDINATION

TEXAS TRANSPORTATION COMMISSION

VARIOUS County

District VARIOUS

MINUTE ORDER

In VARIOUS COUNTIES, projects have been proposed to develop STATE HIGHWAY 99 (Grand Parkway), a proposed 170 mile facility from State Highway 146 in Galveston County to State Highway 146 at Spur 55 in Chambers County.

The completion of the Grand Parkway is essential and urgent, as construction of the projects would alleviate congestion and improve traffic flow in the Houston metropolitan area and the surrounding region.

While the projects have been ongoing since the designation of State Highway 99 by the Texas Transportation Commission (commission), economic conditions and budgetary constraints have affected the ability of the Texas Department of Transportation (department) to continue the development of the Grand Parkway in a timely manner.

There exists the potential for expediting the completion of the Grand Parkway by financing a portion of the design and construction costs through the use of toll financing. The commission recognizes that innovative financing methods, including tolls, are an effective means of maximizing the use of limited available resources, without compromising the quality of the state's transportation system.

To further the expeditious development of the Grand Parkway, Harris County has been requested to conduct traffic and revenue studies of segments of the Grand Parkway for the purpose of determining the feasibility of developing those segments as toll facilities. Harris County is currently performing a comprehensive traffic and revenue study that assumes development of the Grand Parkway as a toll facility, with results of the study due in the summer of 2003.

The commission has determined that constructing and operating the Grand Parkway as a toll facility is the most efficient and expeditious means of ensuring its development, and encourages the development of partnerships and the employment of innovative methods for its financing and construction.

Any change in the assumed operational characteristics of the Grand Parkway, including the development and operation of the Grand Parkway as a toll facility, may require an amendment to the metropolitan transportation plan of the Houston-Galveston Area Council (HGAC), the metropolitan planning organization for the region, and the HGAC transportation improvement program, and will require new modeling in the HGAC Air Quality Conformity Analysis.

House Bill 3545 and Senate Bill 1463, 78th Legislature, 2003, relating to the conversion of a non-tolled state highway to a toll facility, would authorize the commission, if enacted, to convey a non-tolled state highway or a segment of a non-tolled state highway, including any real property acquired to construct or operate the highway, to Harris County for operation and maintenance as a county toll project, or to convert the highway to a department turnpike project.

IT IS THEREFORE ORDERED by the commission that the department is directed to develop an action plan for the development of the Grand Parkway as a toll facility to the extent feasible under current law, including plans for carrying out any necessary studies and making any necessary modifications to the HGAC metropolitan transportation plan, transportation improvement program, and Air Quality Conformity Analysis.

TEXAS TRANSPORTATION COMMISSION

VARIOUS County

MINUTE ORDER

District VARIOUS

IT IS FURTHER ORDERED that the department evaluate and investigate options for converting one or more segments of the Grand Parkway to county toll projects or to department turnpike projects, including, contingent upon the enactment of House Bill 3545, Senate Bill 1463, or similar legislation, proceeding with the implementation of the authority provided in that legislation.

Submitted and reviewed by:

Director, Texas Turnpike Authority Division

Recommended by:

Executive Director

109226 APR 24 03

Minute Number | Date Passed

From the Office of
Larry E. Brown, Plant Taxonomist
6223 Henniker Drive
Houston, Texas 77041 - 5844
❀ ❀ ❀ ❀ ❀ ❀ ❀ ❀ ❀ ❀ ❀ ❀
Home Phone Number: 832 - 467 - 3348
Cell Phone Number: 832 -515 - 8174
E-mail Address: Larry-theplantman@att.net
Alternate E-mail Address: Ruby.brown@att.net

May 19, 2009

To Whom it may Concern, I have been hired by PBSJ to help with a survey for *Hymenoxys texana* (Prairie Dawn) along the proposed right of way of Segment F-1 of the Grand Parkway. This segment extends from U.S. 290 to SH 249 in Harris County Texas.

Methods Used in Survey

Prairie dawn only grows with early flowers from late February into March and forming seeds and later flowers in April. It occurs as small colonies on sparsely vegetated areas of pale, fine-sandy, and compacted soil. The 2009 survey was in April thus numerous plants in full anthesis will be on suitable sites. These sites are sometimes at the base of mima (pimple) mounds. Prairie Dawn is a heliophyte, growing in full sun in undisturbed native prairies. It is not present under trees in woodlands nor on highly disturbed fields such as those caused by plowing and thus overturning the top soil. Soil disturbed sites are often covered with a mixture of introduced and native weedy species thus not the vegetation of native prairies.

PBSJ provided me with fine aerial photographs with the current alignment clearly indicated. I used these aerials to identified potential sites. These sites were in open areas with a pale colored soil exposed. These potential habitat sites are outlined in red lines at site 2 on sheet 11 of 21, at site 4 on sheet 15 of 21, and at site 6 on sheet 18 of 21, and at site 7 on sheet 21 of 21. Photographs were taken on each of these potential habitat sites. In some cases the pale color was due to the death of plants under hay stacks, to small sandy roads, and other man made factors. Areas identified as having no potential Prairie Dawn habitat were densely wooded areas, open areas with a uniform brown color, and those with contour lines that show plowed soils.

Potential Prairie Dawn habitat was located at site 4. It is located on page 287 of the Harris County Key Map on the north side of Selph (Self) road east of Cedar Lane. A Prairie Dawn habitat was located adjacent to the metal gate . The aerial photograph shows a dirt road extending north from the gate and a number of bare soil sites to the west of this dirt road. These bare soil sites are largely to the north of the right of way but the right of way extends across the southern edge of one bare spot. We were unable to obtain permission to examine these sites including the one adjacent to the entrance gate and thus missed an opportunity to determine if Prairie Dawn plants were on these sites. Known Prairie Dawn sites are nearby to the northwest and southwest near Cypress-Rosehill road. By the way, the right of way extends across Cypress-Rosehill and we searched here but no suitable habitat was identified in this area where known Prairie Dawn sites are to the north and to the south.

Qualifications

I have a Ph.D. in plant taxonomy from Texas A&M University. I have conducted about 100 surveys for Prairie Dawn over the past 20 years and have some 30 papers published in floristic plant biology. I am also the co-author of the federal recovery plan for *Hymenoxys texana*.

Survey conditions

The survey of section F-1 in 2009 was conducted on April 15, 16, 17, and 24. At this time Prairie Dawn plants are in full anthesis on suitable sites. Three full days and one half-day were devoted to this segment. We motored to the potential sites picked out on the aerials but most of the time we needed to walk from the vehicle to them. Nathan Olday was on the survey each day and Jeremy Marshall was also on the April 15, 16, and 17 visit.

Summary of survey

We saw no Prairie Dawn plants on the 31/2 day survey. Only site 4 seemed to have suitable habitat, but we were unable to verify Prairie Dawn there because we were unable to secure permission from the land owner for a close-up examination.

Larry E. Brown,

Larry E. Brown

Plant Taxonomist and
Environmental Consultant

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Division of Ecological Services
17629 El Camino Real #211
Houston, Texas 77058-3051
281/286-8282 FAX 281/488-5882

May 27, 2009

Dianna F. Noble
Texas Department of Transportation
125 East 11th Street
Austin, Texas 78701-2483

Dear Ms. Noble:

Thank you for your letter of May 8, 2009, requesting concurrence with the Texas Department of Transportation's (TxDOT) determination that the proposed construction of Segment F-1 of the Grand Parkway (SH 99) is not likely to adversely affect the federally listed endangered Texas prairie dawn-flower (*Hymenoxys texana*). The proposed project extends approximately 12 miles from US 290 to SH 249 in Harris County, Texas.

The U.S. Fish and Wildlife Service concurs with TxDOT's determination that the proposed Segment F-1 of the Grand Parkway is not likely to adversely affect any federally listed species under our jurisdiction. This concurrence is based upon a review of the May 2009 *Biological Evaluation for Grand Parkway Segment F-1, US 290 to SH 249* and on information in our files.

In the event the project changes or additional information on the distribution of listed or proposed species or designated critical habitat becomes available, the project should be reanalyzed for effects not previously considered.

Our comments are provided in accordance with the provisions of the Endangered Species Act of 1973 (87) Stat. 884, as amended; 16 U.S.C. 703 et seq.

Please contact Edith Erfling at 281/286-8282 if you have any questions or if we can be of further assistance.

Sincerely,

Edith Erfling

for Stephen D. Parris
Field Supervisor, Clear Lake ES Field Office

TAKE PRIDE® IN AMERICA

Texas Department of Transportation

DEWITT C. GREER STATE HIGHWAY BLDG. • 125 E. 11TH STREET • AUSTIN, TEXAS 78701-2483 • (512) 463-8585

May 19, 2009

Section 106/Antiquities Code of Texas: Review and Comments (Permit #5275)
State Highway (SH) 99 (Segment F1) Roadway Project (CSJ: 3510-06-002)
Houston District; Harris County

Dr. James E. Bruseth
Department of Antiquities Protection
Texas Historical Commission
P.O. Box 12276
Austin, Texas 78711

Dear Dr. Bruseth:

The proposed project will be undertaken with Federal funding. In accordance with Section 106 and the First Amended Programmatic Agreement among the Texas Department of Transportation (TxDOT), the Texas State Historical Preservation Officer (TSHPO), the Federal Highway Administration (FHWA), and the Advisory Council on Historic Preservation and the Antiquities Code of Texas and the Memorandum of Understanding between the Texas Historical Commission (THC) and TxDOT, this letter continues consultation for the proposed undertaking.

The proposed project would construct the State Highway (SH) 99 outer loop; between Interstate Highway US Highway (US) 290 and State Highway (SH) 249, in Harris County. The proposed roadway would be a four-lane, controlled-access toll road with intermittent frontage roads located within a 400-foot (ft) wide right-of-way (ROW). The proposed project includes bridges over drainages and grade separations at various intersections. The proposed project is approximately 12.0 miles in length. Approximately 582 acres of new right-of-way (ROW) would be acquired; all work would remain within the proposed 400-ft wide corridor. The area of potential effect is defined as the project length, the proposed ROW and any existing ROW that may be utilized, and the depth of construction impacts, no more than 75-ft in depth. This additional consultation is the result of a reevaluation of the proposed project for a proposed design change for a grade separation at the future West Road between Longenbaugh Road and the future Tuckerton Road and inadvertent discrepancies with previously surveyed areas within the APE and attempting to rectify these discrepancies before the proposed ROW that was denied right-of-entry (ROE) is acquired and will soon need an archeological survey as well.

PBS&J, a consultant for the Houston District, conducted a background review and an intensive survey under Permit #5275 for the proposed project. No previously recorded archeological historic properties were identified within the APE of this proposed segment, except for Site 41HR1006, a deteriorating historic-age house site. The Geologic Atlas of Texas, Houston Sheet (Bureau of Economic Geology: 1982) indicates that the proposed project APE is within an area mapped as Pleistocene Lissie and Beaumont Formations and Holocene Alluvium. The Lissie and Beaumont surfaces have negligible potential to contain artifacts dating from demonstrated, culturally relevant periods. The Soil Survey of Harris County, Texas (USDA-SCS: 1976) indicates that the proposed project APE is within an area mapped as the Wockley-Gessner soil association and the Segno-Hockley soil association. The Wockley-Gessner soils and Segno-Hockley soils have the best potential for pimple mounds and alluvium that might contain prehistoric archeological materials.

The Houston Potential Archeological Liability Map (PALM) indicates the proposed project crosses the following PALM map units. PALM Unit #4, recommended no archeological survey needed. PALM Unit #2a recommended surface survey of intact pimple mounds only. PALM Unit #2 recommended an archeological surface survey only. PALM Unit #1 recommended an intensive archeological survey with mechanical trenching if deep impacts are anticipated; however, ROE was denied for the only area within the APE that was mapped as Unit #1.

PBS&J surveyed approximately 159.33 acres during this survey. A total of 90 shovel-tests were excavated during the pedestrian survey. No cultural resources were encountered during the survey. PBS&J recommends that no further archeological work is needed within the portion of the APE that has had the inventory completed. However, it should be noted the proposed grade separation at the future Mason Road is located in an area that was not surveyed due to lack of ROE.

Please find attached for your review and comments the PBS&J draft report; *An Cultural Survey of the Preferred Alignment for Segment F1 of the Grand Parkway Project, Harris County, Texas*. TxDOT recommends that the report is satisfactory and acceptable; minor comments have already been submitted to PBS&J. PBS&J has already responded to TxDOT's comments and are making the appropriate changes for the final report. TxDOT requests your concurrence that; 1) the areas surveyed by this 2009 survey are complete and do not warrant any additional archeological investigation and 2) the remainder of the proposed project APE that has been denied ROE, including the proposed Mason Road grade separation, still warrants archeological work to complete the inventory. TxDOT further recommends that the remainder of the archeological inventory be deferred to allow NEPA processing and property acquisition to proceed; once the property has been acquired, TxDOT shall be obligated to complete the inventory. If you have no objections to the above request and recommendation, and have no comments on this report and find it acceptable, please sign below to indicate your concurrence and stamp the draft cover as acceptable.

Thank you for your consideration in this matter. If you have any questions or further need of assistance, please contact Allen Bettis of the TxDOT Archeological Studies Program at (512) 416-2747.

Sincerely,

Allen C. Bettis Jr.
Archeological Studies Program
Environmental Affairs Division

cc w/o attachments: Dale Norton – PBS&J – Houston
Susan Theiss – Houston District APD
ACB DGN PA File

Concurrence: 5-21-09 Date:
for F. Lawerence Oaks, State Historic Preservation Officer

Document No. 090090
PBS&J Job No. 100008595

A Cultural Resources Survey of the Preferred Alignment for Segment F-1 of the Grand Parkway Project Harris County, Texas

CSJ: 3510-06-02

Texas Antiquities Permit No. 5275

Prepared for:

Texas Department of Transportation
7721 Washington
Houston, Texas 77251

Prepared by:

PBS&J
1250 Wood Branch Park Drive
Suite 300
Houston, Texas 77079

Principal Investigator:
Karla Córdova

Report Authors:
Darren Schubert
Dale Norton

May 2009

DRAFT REPORT
ACCEPTABLE
Please submit 20 final report copies
by [signature]
for F. Lawerence Oaks
State Historic Preservation Officer
Date 5-21-09
Track#

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Planet Protectors For Kids!

Combustion

To reduce waste volume, local governments or private operators can implement a controlled burning process called combustion or incineration. In addition to reducing volume, combustors, when properly equipped, can convert water into steam to fuel heating systems or generate electricity. Incineration facilities can also remove materials for recycling.

Over one-fifth of the U.S. municipal solid waste incinerators use refuse derived fuel (RDF). In contrast to mass burning—where the municipal solid waste is introduced "as is" into the combustion chamber—RDF facilities are equipped to recover recyclables (e.g., metals, cans, glass) first, then shred the combustible fraction into fluff for incineration.

A variety of pollution control technologies significantly reduce the gases emitted into the air, including:

- Scrubbers—devices that use a liquid spray to neutralize acid gases
- Filters—remove tiny ash particles

Burning waste at extremely high temperatures also destroys chemical compounds and disease-causing bacteria. Regular testing ensures that residual ash is non-hazardous before being landfilled. About ten percent of the total ash formed in the combustion process is used for beneficial use such as daily cover in landfills and road construction.

Related Topics

Combustion and Incineration Regulations: 40 CFR Part 60
(Subchapter C—Air Programs)
Combustion and incineration regulations are codified in 40 CFR Part 60, including emissions guidelines and compliance times for municipal waste combustors.

Guidance for the Sampling and Analysis of Municipal Waste Combustion Ash for the Toxicity Characteristic (PDF) (28 pp, 1.0 MB, About PDF)

Electricity from Municipal Solid Waste (MSW)
This EPA Web site explains how MSW can be directly combusted in waste-to-energy facilities to generate electricity. Because no new fuel sources are used other than the waste that would otherwise be sent to landfills, MSW is often considered a renewable power source.

Research on Municipal Waste Combustion (MWC) Pollutant Formation and Control Mechanisms
EPA's Air Pollution Technology Branch (part of EPA's National Risk Management Research Laboratory) conducts research on air pollutant emissions generated during the process of municipal solid waste combustion.

Clean Energy Home
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Site Map

Energy and You
How does electricity affect the environment?
How clean is the electricity I use? Power Profiler
How can I reduce my impact?
Glossary

Municipal Solid Waste

Electricity from Municipal Solid Waste

Municipal solid waste (MSW) refers to the stream of garbage collected through community sanitation services. Medical wastes from hospitals and items that can be recycled are generally excluded from MSW used to generate electricity. Paper and yard wastes account for the largest share of the municipal waste stream,[1] and much of this can be recycled directly or composted.

Electricity Generation Technologies

- Natural Gas
- Coal
- Oil
- Nuclear Energy
- Municipal Solid Waste
- Hydroelectricity
- Non-Hydroelectric Renewable Energy

Currently, over 30 percent of MSW generated in the United States is recycled annually. While not producing this waste in the first place is the preferred management strategy for this material, recycling is preferred over any method of disposal. The majority of MSW that is not recycled is typically sent to landfills after it is collected. As an alternative, MSW can be directly combusted in waste-to-energy facilities to generate electricity. Because no new fuel sources are used other than the waste that would otherwise be sent to landfills, MSW is often considered a renewable power source. Although MSW consists mainly of renewable resources such as food, paper, and wood products, it also includes nonrenewable materials derived from fossil fuels, such as tires and plastics.

At the power plant, MSW is unloaded from collection trucks and shredded or processed to ease handling. Recyclable materials are separated out, and the remaining waste is fed into a combustion chamber to be burned. The heat released from burning the MSW is used to produce steam, which turns a steam turbine to generate electricity.

The United States has about 89[2] operational MSW-fired power generation plants, generating approximately 2,500 megawatts, or about 0.3 percent of total national power generation. However, because construction costs of new plants have increased, economic factors have limited new construction.

Environmental Impacts

Although power plants are regulated by both federal and state laws to protect human health and the environment, there is a wide variation of environmental impacts associated with power generation technologies. The purpose of the following section is to give consumers a better idea of the specific air, water, land, and solid waste impacts associated with MSW-fired electricity generation.

Air Emissions Impacts

Burning MSW produces nitrogen oxides and sulfur dioxide as well as trace amounts of toxic pollutants, such as mercury compounds and dioxins. Although MSW power plants do emit carbon dioxide, the primary greenhouse gas, the biomass-derived portion is considered to be part of the Earth's natural carbon cycle. The plants and trees that make up the paper, food, and other biogenic waste remove carbon dioxide from the air while they are growing, which is returned to the air when this material is burned. In contrast, when fossil fuels (or products derived from them such as plastics) are burned, they release carbon dioxide that has not been part of the Earth's atmosphere for a very long time (i.e., within a human time scale).

The average air emission rates in the United States from municipal solid waste-fired generation are: 2988 lbs/MWh of carbon dioxide, (it is estimated that the fossil fuel-derived portion of carbon dioxide emissions represent approximately one-third of the total carbon emissions) 0.8 lbs/MWh of sulfur dioxide, and 5.4 lbs/MWh of nitrogen oxides.[3]

The variation in the composition of MSW affects the emissions impact. For example, if MSW containing batteries and tires are burned, toxic materials can be released into the air. A variety of air pollution control technologies are used to reduce toxic air pollutants from MSW power plants.

There can be significant greenhouse gas reduction benefits from recycling and source reduction when compared to other management options. Note also that over 1.6 million ton of ferrous and non-ferrous metals, plastics, glass and combustion ash are recycled annually.[4]

Water Resource Use

Power plants that burn MSW are normally smaller than fossil fuel power plants but typically require a similar amount of water per unit of electricity generated. When water is removed from a lake or river, fish and other aquatic life can be killed, affecting those animals and people who depend on these resources.

Water Discharges

Similar to fossil fuel power plants, MSW power plants discharge used water. Pollutants build up in the water used in the power plant boiler and cooling system. In addition, the cooling water is considerably warmer when it is discharged than when it was taken. These water pollutants and the higher temperature of the discharged water can upon its release negatively affect water quality and aquatic life. This discharge usually requires a permit and is monitored. For more information about these regulations, visit EPA's Office of Water Web site.

Solid Waste Generation

The combustion of MSW reduces MSW waste streams, reducing the creation of new landfills. MSW combustion creates a solid waste called ash, which can contain any of the elements that were originally present in the waste. MSW power plants reduce the need for landfill capacity because disposal of MSW ash requires less land area than does unprocessed MSW. However, because ash and other residues from MSW operations may contain toxic materials, the power plant wastes must be tested regularly to assure that the wastes are safely disposed to prevent toxic substances from migrating into ground-water supplies. Under current regulations, MSW ash must be sampled and analyzed regularly to determine whether it is hazardous or not.[5] Hazardous ash must be managed and disposed of as hazardous waste. Depending on state and local restrictions, non-hazardous ash may be disposed of in a MSW landfill or recycled for use in roads, parking lots, or daily covering for sanitary landfills.

Land Resource Use

MSW power plants, much like fossil fuel power plants, require land for equipment and fuel storage. The non-hazardous ash residue from the burning of MSW is typically deposited in landfills.

Fuel Reserves

U.S. residents, businesses, and institutions produced more than 229 million tons of MSW in 2001, which is equivalent to approximately 4.4 pounds of waste per person per day. In 2001, 33.6 million tons (14.7 per cent) of MSW were combusted.[6]

1. U.S. EPA, Office of Solid Waste, Basic Facts.
2. A Look at Waste-to-Energy/Maria Zannes, IWSA; presented at the NAWTEC Fall 2004 Meeting, Columbia

University, NYC.
3. U.S. EPA, Compilation of Air Pollutant Emission Factors (AP-42).
4. Kiser, Jonathan V. L., Recycling and Waste-to-Energy: The Ongoing Compatibility Success Story EXIT Disclaimer, MSW Management, May/June 2003.
5. U.S. EPA, Office of Solid Waste, MSW Disposal.
6. Municipal Solid Waste in the United States: 2001 Facts and Figures. EPA530-S--011.

Query Results

SDWIS

Report an Error

Query Selections:
State selected: **TEXAS**
County selected: **GRAYSON**
Population Selected: **Very Small (0-500), Small (501-3,300), Medium (3,301-10,000), Large (10,001-100,000), Very Large (100,000+)**
Water System Status: **active**
Query executed on: **JAN-15-2010**
Results are based on data extracted on : **OCT-16-2009**

List of Water Systems in SDWIS

Information about water systems in TEXAS is maintained by Texas Natural Resource Cons Com .

To obtain additional information about drinking water please call EPA's Safe Drinking Water hotline at 1-800-426-4791.

Community Water Systems: Water Systems that serve the same people year-round (e.g. in homes or businesses).

Water System Name	County(s) Served	Population Served	Primary Water Source Type	System Status	Water System ID
CARRIAGE HOUSE ESTATES	GRAYSON	411	Purch_surface_water	Active	TX0910082
CITY OF BELLS	GRAYSON	1300	Groundwater	Active	TX0910001
CITY OF COLLINSVILLE	GRAYSON	1457	Groundwater	Active	TX0910005
CITY OF DENISON	GRAYSON	26949	Surface_water	Active	TX0910003
CITY OF DORCHESTER	GRAYSON	1512	Groundwater	Active	TX0910028
CITY OF GUNTER	GRAYSON	1419	Groundwater	Active	TX0910012
CITY OF HOWE	GRAYSON	2670	Purch_surface_water	Active	TX0910013
CITY OF KNOLLWOOD	GRAYSON	360	Purch_surface_water	Active	TX0910146
CITY OF POTTSBORO	GRAYSON	2157	Purch_surface_water	Active	TX0910004
CITY OF SADLER	GRAYSON	450	Groundwater	Active	TX0910014
CITY OF SHERMAN	GRAYSON	38047	Surface_water	Active	TX0910006
CITY OF SOUTHMAYD	GRAYSON	462	Groundwater	Active	TX0910045
CITY OF TIOGA	GRAYSON	1059	Groundwater	Active	TX0910007
CITY OF TOM BEAN	GRAYSON	1302	Groundwater	Active	TX0910008
CITY OF VAN ALSTYNE	GRAYSON	2890	Purch_surface_water	Active	TX0910009
CITY OF WHITESBORO	GRAYSON	3948	Groundwater	Active	TX0910010
CITY OF WHITEWRIGHT	GRAYSON	2000	Groundwater	Active	TX0910011
ELMONT FARMINGTON WSC	GRAYSON	1398	Groundwater	Active	TX0910055
GAINESVILLE BOAT CLUB	GRAYSON	297	Groundwater	Active	TX0910069
HERITAGE ESTATES	GRAYSON	33	Groundwater	Active	TX0910139
HIGH COUNTRY ESTATES	GRAYSON	276	Groundwater	Active	TX0910112
KENTUCKYTOWN WSC	GRAYSON	2850	Groundwater	Active	TX0910060
KYKER LANE COMMUNITY WATER SYSTEM	GRAYSON	42	Groundwater	Active	TX0910125
LAKE TEXOMA VFW POST 7873	GRAYSON	200	Groundwater	Active	TX0910086
LUELLA WSC	GRAYSON	3243	Groundwater	Active	TX0910032
MARILEE SUD	GRAYSON	4776	Groundwater	Active	TX0910081
MUNSON POINT PROPERTY OWNERS ASSOCIATION	GRAYSON	27	Purch_surface_water	Active	TX0910140
NORTHERN HILLS WATER SERVICE	GRAYSON	211	Purch_surface_water	Active	TX0910126

NORTHWEST GRAYSON COUNTY WCID 1	GRAYSON	1923	Groundwater	Active	TX0910137
OAK CREEK MOBILE HOME PARK	GRAYSON	63	Groundwater	Active	TX0910072
OAK RIDGE SOUTH GALE WSC	GRAYSON	2466	Purch_groundwater	Active	TX0910033
PINK HILL WSC	GRAYSON	2049	Groundwater	Active	TX0910034
PRESTON CLUB UTILITY CORPORATION	GRAYSON	111	Groundwater	Active	TX0910143
RIDGECREST	GRAYSON	1482	Purch_surface_water	Active	TX0910035
ROCKY POINT ESTATES	GRAYSON	321	Purch_surface_water	Active	TX0910038
RRA PRESTON SHORES WATER SYSTEM	GRAYSON	2133	Surface_water	Active	TX0910037
SHERWOOD SHORES	GRAYSON	1740	Groundwater	Active	TX0910040
SOUTH GRAYSON WSC	GRAYSON	4860	Groundwater	Active	TX0910064
STARR WSC	GRAYSON	2232	Groundwater	Active	TX0910046
TANGLEWOOD ON TEXOMA	GRAYSON	3507	Purch_surface_water	Active	TX0910052
TEXOMA ESTATES WSC	GRAYSON	180	Groundwater	Active	TX0910047
THOMPSON HEIGHTS WATER SYSTEM	GRAYSON	324	Purch_surface_water	Active	TX0910085
TWO WAY SUD	GRAYSON	4395	Groundwater	Active	TX0910022
WESTVIEW SUBDIVISION	GRAYSON	759	Groundwater	Active	TX0910048

Non-Transient Non-Community Water Systems: Water Systems that serve the same people, but not year-round (e.g. schools that have their own water system).

Water System Name	County(s) Served	Population Served	Primary Water Source Type	System Status	Water System ID
HIGHPORT MARINA	GRAYSON	424	Purch_groundwater	Active	TX0910130

Transient Non-Community Water Systems: Water Systems that do not consistently serve the same people (e.g. rest stops, campgrounds, gas stations).

Water System Name	County(s) Served	Population Served	Primary Water Source Type	System Status	Water System ID
BIG MINERAL CAMP RESORT	GRAYSON	282	Groundwater	Active	TX0910066
FLOWING WELLS RESORT	GRAYSON	159	Groundwater	Active	TX0910108
GRANDPAPPY POINT	GRAYSON	1864	Groundwater	Active	TX0910131
MARLENE CANNON RESTAURANT	GRAYSON	25	Groundwater	Active	TX0910144
MOBILE WATER SYSTEM	GRAYSON	25	Purch_surface_water	Active	TX0910136
PATSYS CAFE	GRAYSON	200	Groundwater	Active	TX0910128
SANDUSKY OUTPOST	GRAYSON	25	Groundwater	Active	TX0910149
SHEPPARD AFB RECREATIONAL ANNEX	GRAYSON	261	Groundwater	Active	TX0910090
TEXINS TEXOMA CLUB	GRAYSON	744	Groundwater	Active	TX0910084
TEXOMA MARINA AND RESORT	GRAYSON	360	Groundwater	Active	TX0910120

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Last updated on Friday, January 15th, 2010.
http://oaspub.epa.gov/enviro/sdw_query_v2.get_list?wsys_name=&fac_search=fac_beginning&fac_county=GRAYSON&pop_serv=500&pop_serv=3300&pop_serv=10000&pop_serv=100000&pop_serv=100001&sys_status=active&pop_serv=&wsys_id=&fac_state=TX&last_fac_name=&page=1&query_results=&total_rows_found=
Print As-Is

U.S. ENVIRONMENTAL PROTECTION AGENCY

Facility Registry System (FRS)

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Facility Detail Report

FRS

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BIG BROWN STEAM ELECTRIC STATION
FM 2570
FAIRFIELD, TX 75840
EPA Registry Id: 110000598988

Legend
- ★ Selected Facility
- EPA Facility of Interest
- State/Tribe Facility of Interest

The facility locations displayed come from the FRS Spatial Coordinates tables. They are the best representative locations for the displayed facilities based on the accuracy of the collection method and quality assurance checks performed against each location. The North American Datum of 1983 is used to display all coordinates.

Environmental Interests

Information System	Information System ID	Environmental Interest Type	Data Source	Last Updated Date	Supplemental Environmental Interests:
AIR FACILITY SYSTEM	4816100002	AIR MAJOR ()	AIRS/AFS	08/18/2009	**ICIS**-ENFORCEMENT/COMPLIANCE ACTIVITY
CLEAN AIR MARKETS DIVISION (CAMD) BUSINESS SYSTEMS	3497	AIR PROGRAM	CAMDBS	11/10/2008	
EMISSIONS & GENERATION RESOURCE INTEGRATED DATABASE	3497	ELECTRIC POWER GENERATOR (COAL BASED)	EGRID		
INTEGRATED COMPLIANCE INFORMATION SYSTEM	37256	FORMAL ENFORCEMENT ACTION	ICIS	04/20/2001	**ICIS**-06-2001-0099 FORMAL ENFORCEMENT ACTION
NATIONAL EMISSIONS INVENTORY	NEI8424	CRITERIA AND HAZARDOUS AIR POLLUTANT INVENTORY	NEI		
NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (ICIS-NPDES)	TX0030180	ICIS-NPDES MAJOR	ICIS	04/18/2007	**ICIS**-ENFORCEMENT/COMPLIANCE ACTIVITY
PERMIT COMPLIANCE SYSTEM	TX0030180	NPDES MAJOR	NPDES PERMIT	07/31/2006	
RESOURCE CONSERVATION AND RECOVERY ACT INFORMATION SYSTEM	TXD000821272	CESQG (ACTIVE)	RCRAINFO	04/09/2008	
RESOURCE CONSERVATION AND RECOVERY ACT INFORMATION SYSTEM	TXD000821280	CESQG (ACTIVE)	RCRAINFO	12/02/2009	
TOXIC RELEASE INVENTORY SYSTEM	75840BGBRW11MIE	TRI REPORTER	TRI REPORTING FORM	06/30/2009	
					PERMIT-53205 AIR PROGRAM **EPA ID**-TXD000821280

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY - AGENCY CENTRAL REGISTRY	RN101198059	STATE MASTER	TX-TCEQ ACR		HAZARDOUS WASTE PROGRAM **REGISTRATION**-0810004 COMMUNITY WATER SYSTEM **REGISTRATION**-81705 AIR PROGRAM **PERMIT**-17891 AIR PROGRAM **PERMIT**-WQ0001309000 NPDES PERMIT **REGISTRATION**-77138 AIR PROGRAM **SOLID WASTE REGISTRA**-35877 HAZARDOUS WASTE PROGRAM **SOLID WASTE REGISTRA**-34681 HAZARDOUS WASTE PROGRAM **REGISTRATION**-78297 AIR PROGRAM **EPA ID**-TXD000821272 HAZARDOUS WASTE PROGRAM **ACCOUNT NUMBER**-FI0020W AIR PROGRAM **REGISTRATION**-83646 AIR PROGRAM **PERMIT**-45420 AIR PROGRAM **PERMIT**-4069 AIR PROGRAM **PERMIT**-18744 AIR PROGRAM **REGISTRATION**-72206 AIR PROGRAM **REGISTRATION**-85296 AIR PROGRAM **AFS NUM**-4816100002 AIR PROGRAM **REGISTRATION**-83647 AIR PROGRAM **PERMIT**-1935 AIR PROGRAM **REGISTRATION**-46722 AIR PROGRAM **REGISTRATION**-81476 AIR PROGRAM **PERMIT**-TPDES0030180 NPDES PERMIT **ACCOUNT NUMBER**-FI0020W AIR PROGRAM **PERMIT**-39099 HAZARDOUS WASTE PROGRAM **SOLID WASTE REGISTRA**-30080 HAZARDOUS WASTE PROGRAM **PERMIT**-56445 AIR PROGRAM **PERMIT**-78759 AIR PROGRAM **PERMIT**-56447 AIR PROGRAM **SOLID WASTE REGISTRA**-30080 CORRECTIVE ACTION **REGISTRATION**-54810 AIR PROGRAM **PERMIT**-TX0030180 NPDES PERMIT **PERMIT**-8066 AIR PROGRAM **PERMIT**-65 AIR PROGRAM **EPA ID**-PSDTX1065 AIR PROGRAM **PCS**-PAG049546 NPDES PERMIT
TEXAS COMMISSION ON ENVIRONMENTAL QUALITY - AGENCY CENTRAL REGISTRY	RN105415939	STATE MASTER	TX-TCEQ ACR		**PERMIT**-TXR05W662 STORMWATER **PERMIT**-TXR05W662 NPDES STORMWATER PERMIT

Additional EPA Reports: MyEnvironment Enforcement and Compliance Site Demographics Watershed Report

Standard Industrial Classification Codes (SIC)

Data Source	SIC Code	Description	Primary
NEI	4911	ELECTRIC SERVICES	
ICIS	4911	ELECTRIC SERVICES	
TX-TCEQ ACR	1221	BITUMINOUS COAL AND LIGNITE SURFACE MINING	
TRIS	4911	ELECTRIC SERVICES	
CAMDBS	4911	ELECTRIC SERVICES	
AIRS/AFS	4911	ELECTRIC SERVICES	
FRS	1221	BITUMINOUS COAL AND LIGNITE SURFACE MINING	
TX-TCEQ ACR	4911	ELECTRIC SERVICES	
TX-TCEQ ACR	4911	ELECTRIC SERVICES	
PCS	4911	ELECTRIC SERVICES	
NPDES	4911	ELECTRIC SERVICES	
TRIS	1221	BITUMINOUS COAL AND LIGNITE SURFACE MINING	

Facility Codes and Flags

EPA Region:	06
Duns Number:	
Congressional District Number:	05
Legislative District Number:	09
HUC Code/Watershed:	12030201 / LOWER TRINITY-TEHUACANA
US Mexico Border Indicator:	NO
Federal Facility:	NO
Tribal Land:	NO

Alternative Names

Alternative Name	Source of Data
BIG BROWN	CAMDBS
TXU BIG BROWN STEAM ELECTRIC STATION	AIRS/AFS
TEXAS UTILITIES ELECTRIC CO	NPDES PERMIT
txu BIG BROWN STEAM ELECTRIC STATION & LIGNITE MINE	TRI REPORTING FORM
BIG BROWN STEAM ELECTRIC STATION & LIGNITE MINE	TRI REPORTING FORM
TXU BIG BROWN COMPANY LP(OWNER	NPDES PERMIT
TEXAS UTILITIES GENERATING COMPANY	AIRS/AFS
LUMINANT POWER	TRI REPORTING FORM
TEXAS UTILITIES MINING CO-TUMCO	RCRAINFO
TXU BIG BROWN COMPANY LP	RCRAINFO
TU ELECTRIC BIG BROWN SES	RCRAINFO
BIG BROWN POWER COMPANY LLC	NPDES PERMIT

Organizations

Affiliation Type	Name	DUNS Number	Information System	Mailing Address
OWNER1	TXU GENERATION CO LP		EGRID	
OWNER	BIG BROWN POWER COMPANY LLC		PCS	View
OPERATOR	LUMINANT MINING COMPANY LLC		RCRAINFO	View
OWNER/OPERATOR		010311110	TRIS	
OWNER/OPERATOR		075107029	AIRS/AFS	
OPERATOR	TXU GENERATION CO LP		EGRID	
OPERATOR	LUMINANT GENERATION COMPANY LLC		CAMDBS	
OWNER	BIG BROWN POWER COMPANY LLC		NPDES	View

National Industry Classification System Codes (NAICS)

Data Source	NAICS Code	Description	Primary
TX-TCEQ ACR	221119	OTHER ELECTRIC POWER GENERATION.	
TX-TCEQ ACR	221122	ELECTRIC POWER DISTRIBUTION.	
TX-TCEQ ACR	221112	FOSSIL FUEL ELECTRIC POWER GENERATION.	
TRIS	221112	FOSSIL FUEL ELECTRIC POWER GENERATION.	
TX-TCEQ ACR	212111	BITUMINOUS COAL AND LIGNITE SURFACE MINING.	
RCRAINFO	221112	FOSSIL FUEL ELECTRIC POWER GENERATION.	
RCRAINFO	212111	BITUMINOUS COAL AND LIGNITE SURFACE MINING.	
TRIS	221122	ELECTRIC POWER DISTRIBUTION.	
TX-TCEQ ACR	221112	FOSSIL FUEL ELECTRIC POWER GENERATION.	
NEI	221122	ELECTRIC POWER DISTRIBUTION.	
NEI	221112	FOSSIL FUEL ELECTRIC POWER GENERATION.	
CAMDBS	221112	FOSSIL FUEL ELECTRIC POWER GENERATION.	
FRS	212111	BITUMINOUS COAL AND LIGNITE SURFACE MINING.	

Facility Mailing Addresses

Affiliation Type	Delivery Point	City Name	State	Postal Code	Information System
OWNER	500 NORTH AKARD STREET	DALLAS	TX	75201	NPDES
REGULATORY CONTACT	500 N AKARD ST LINCOLN PLAZA 9TH F	DALLAS	TX	75201	RCRAINFO
OWN	PO BOX 867	PETERSBURG	PA	26847	TX-TCEQ ACR
ALTERNATE CONTACT	500 N. AKARD	DALLAS	TX	75201	CAMDBS
OPERATOR	1601 BRYAN ST	DALLAS	TX	75201	RCRAINFO
REGULATORY CONTACT	500 N AKARD ST C/O ENVIRONMENTAL S	DALLAS	TX	75201	RCRAINFO
MAILING ADDRESS	500 N AKARD ST	DALLAS	TX	752013302	TX-TCEQ ACR
OWNER	500 N AKARD ST	DALLAS	TX	752013302	TX-TCEQ ACR
MAILING ADDRESS	10321 OLD ROUTE 99	MCKEAN	PA	16426-1735	TX-TCEQ ACR
MAILING ADDRESS	1601 BRYAN ST	DALLAS	TX	752013430	TX-TCEQ ACR
FACILITY MAILING ADDRESS	1601 BRYAN STREET	DALLAS	TX	75201	AIRS/AFS
OWNER	500 N AKARD ST LINCOLN PLAZA 9TH F	DALLAS	TX	75201	RCRAINFO
FACILITY MAILING ADDRESS	500 N AKARD LP-09-110C	DALLAS	TX	75201	TRIS
OWN	10321 OLD ROUTE 99	MCKEAN	PA	16426-1735	TX-TCEQ ACR
OWN	PO BOX 2967	HOUSTON	PA	77252-2967	TX-TCEQ ACR
MAILING ADDRESS	ATTN: ZEKE MARTINEZ	DALLAS	TX	75201	NPDES
FACILITY MAILING ADDRESS	500 N AKARD LP-09-110A	DALLAS	TX	75201	TRIS
OTHER	9231 EDINBORO RD	MCKEAN	PA	16426-0062	TX-TCEQ ACR
OTHER	9030 PAULA WAY	MCKEAN	PA	16426-1422	TX-TCEQ ACR
OWNOP	PO BOX 867	PETERSBURG	PA	26847	TX-TCEQ

OWNER	LUMINANT BIG BROWN MINING COMPANY LLC		TX-TCEQ ACR	View
OWNER	BIG BROWN POWER COMPANY LLC		CAMDBS	
OPERATOR	LUMINANT GENERATION CO LLC		RCRAINFO	View
REGULATORY CONTACT	BIG BROWN POWER COMPANY LLC		CAMDBS	
MAILING ADDRESS	BIG BROWN POWER COMPANY LLC		NPDES	View
REGULATORY CONTACT	LUMINANT GENERATION COMPANY LLC		CAMDBS	
OWNER	LUMINANT BIG BROWN MINING COMPANY LLC		RCRAINFO	View
OWNER	LUMINANT GENERATION CO LLC		RCRAINFO	View
OPERATOR	LUMINANT GENERATION COMPANY LLC		TX-TCEQ ACR	View
PARENT ORGANIZATION	ENERGY FUTURE HOLDINGS (TXU)		EGRID	
PARENT ORGANIZATION	LUMINANT GENERATION CO LLC	010311110	TRIS	

					ACR
OTHER	PO BOX 30	MARBLE	PA	16334-0030	TX-TCEQ ACR
OWNER	500 NORTH AKARD STREET	DALLAS	TX	75201	PCS
OWNER	500 N AKARD ST	DALLAS	TX	75201	RCRAINFO
OWN	9030 PAULA WAY	MCKEAN	PA	16426-1422	TX-TCEQ ACR
OPERATOR	1601 BRYAN ST	DALLAS	TX	752013430	TX-TCEQ ACR
OTHER	600 RIGHTERS FERRY RD	BALA CYNWYD	PA	19004	TX-TCEQ ACR
FACILITY MAILING ADDRESS	500 N AKARD ST LINCOLN PLAZA 9TH F	DALLAS	TX	75201	RCRAINFO
OPERATOR	500 N AKARD ST LINCOLN PLAZA 9TH F	DALLAS	TX	75201	RCRAINFO
PRIMARY CONTACT	500 N. AKARD STREET	DALLAS	TX	75201	CAMDBS
PRIMARY MAILING ADDRESS	ATTN: ZEKE MARTINEZ	DALLAS	TX	75201	PCS
OTHER	133 PEACHTREE ST	ATLANTA	PA	30303-1808	TX-TCEQ ACR

Contacts

Affiliation Type	Full Name	Office Phone	Information System	Mailing Address
REGULATORY CONTACT	JEFF JONES	2148758297	RCRAINFO	View
PUBLIC CONTACT	J. R. ROBERTSON	2148758317	TRIS	
OTHER	JANICE T DENNIS	8144767414	TX-TCEQ ACR	View
OWN			TX-TCEQ ACR	View
OWNOP	TOM PLAUGHER	3042572342	TX-TCEQ ACR	View
OTHER	JAMES J LOBUE	8143688700	TX-TCEQ ACR	View
ALTERNATE CONTACT	STEPHEN G HORN	2148758639	CAMDBS	View
OTHER	RALPH DEFELICE	8144761598	TX-TCEQ ACR	View
OTHER	MARK LAUER	8143547304	TX-TCEQ ACR	View
REGULATORY CONTACT	RICHARD WISTRAND		CAMDBS	
OWN	DAVID E SOZA	7135468214	TX-TCEQ ACR	View
OTHER	ROBERT E COATES	6106170600	TX-TCEQ ACR	View
COMPLIANCE CONTACT	DAVID LAMB	2148128482	AIRS/AFS	
OWN	RALPH DEFELICE	8144761598	TX-TCEQ ACR	View
REGULATORY CONTACT	SID STROUD	2148125603	RCRAINFO	View
COGNIZANT OFFICIAL	GARY SPICER	2148128699	PCS	
REGULATORY CONTACT	STEVE KOPENITZ		CAMDBS	
PRIMARY CONTACT	RIC FEDERWISCH	2148758936	CAMDBS	View
OWN	TOM PLAUGHER	3042572342	TX-TCEQ ACR	View

Query executed on: FEB-04-2010

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Last updated on Thursday, February 4th, 2010.
http://iaspub.epa.gov/enviro/fii_query_dtl.disp_program_facility?p_registry_id=110000598988
Print As-Is

Facility Detail Report

FRS

Report an Error

BIG BROWN LIGNITE MINING AREA
11 MILES NORTHEAST OF FAIRFIELD TX ON FM 2570
FAIRFIELD, TX 75840
EPA Registry Id: 110033229897

Legend

- ★ Selected Facility
- EPA Facility of Interest
- State/Tribe Facility of Interest

The facility locations displayed come from the FRS Spatial Coordinates tables. They are the best representative locations for the displayed facilities based on the accuracy of the collection method and quality assurance checks performed against each location. The North American Datum of 1983 is used to display all coordinates.

Environmental Interests

Information System	Information System ID	Environmental Interest Type	Data Source	Last Updated Date	Supplemental Environmental Interests:
TEXAS COMMISSION ON ENVIRONMENTAL QUALITY - AGENCY CENTRAL REGISTRY	RN103013892	STATE MASTER	TX-TCEQ ACR		**SOLID WASTE REGISTRA**-34681 IHW CORRECTIVE ACTION **SOLID WASTE REGISTRA**-34681 INDUSTRIAL AND HAZARDOUS WASTE GENERATION **PERMIT**-35979 AIR NEW SOURCE PERMITS **REGISTRATION**-77485 AIR NEW SOURCE PERMITS **REGISTRATION**-77926 AIR NEW SOURCE PERMITS **REGISTRATION**-77937 AIR NEW SOURCE PERMITS **REGISTRATION**-77938 AIR NEW SOURCE PERMITS **PERMIT**-TPDES0000752 WASTEWATER **PERMIT**-TX0000752 WASTEWATER **ID NUMBER**-TX07045 DAM SAFETY **EPA ID**-TXD000821272 INDUSTRIAL AND HAZARDOUS WASTE GENERATION **PERMIT**-TXR05K099 STORMWATER **PERMIT**-WQ0002700000 WASTEWATER **SOLID WASTE REGISTRA**-34681 HAZARDOUS WASTE PROGRAM **SOLID WASTE REGISTRA**-34681 CORRECTIVE ACTION **PERMIT**-TXR05K099

					NPDES STORMWATER PERMIT **PERMIT**-TX0000752 NPDES PERMIT **PERMIT**-WQ0002700000 NPDES PERMIT **PERMIT**-35979 AIR PROGRAM **REGISTRATION**-77485 AIR PROGRAM **ID NUMBER**-TX07045 DAM SITE **REGISTRATION**-77926 AIR PROGRAM **EPA ID**-TXD000821272 HAZARDOUS WASTE PROGRAM **PERMIT**-TPDES0000752 NPDES PERMIT **REGISTRATION**-77938 AIR PROGRAM **REGISTRATION**-77937 AIR PROGRAM **ACCOUNT NUMBER**-FI0102T AIR PROGRAM **REGISTRATION**-71937 AIR PROGRAM **AFS NUM**-4816100634 AIR PROGRAM

Additional EPA Reports: MyEnvironment Site Demographics Watershed Report

Standard Industrial Classification Codes (SIC)

Data Source	SIC Code	Description	Primary
TX-TCEQ ACR	1221	BITUMINOUS COAL AND LIGNITE SURFACE MINING	

National Industry Classification System Codes (NAICS)

Data Source	NAICS Code	Description	Primary
TX-TCEQ ACR	212111	BITUMINOUS COAL AND LIGNITE SURFACE MINING.	

Facility Codes and Flags

EPA Region:	06
Duns Number:	
Congressional District Number:	
Legislative District Number:	
HUC Code / Watershed:	12030201 / LOWER TRINITY-TEHUACANA
US Mexico Border Indicator:	NO
Federal Facility:	
Tribal Land:	

Alternative Names

No Alternative Names returned.

Organizations

Affiliation Type	Name	DUNS Number	Information System	Mailing Address
OWNER	TXU BIG BROWN MINING COMPANY, LP	044632834	TX-TCEQ ACR	View
OPERATOR	TXU MINING COMPANY LP	044632834	TX-TCEQ ACR	View

Facility Mailing Addresses

Affiliation Type	Delivery Point	City Name	State	Postal Code	Information System
MAILING ADDRESS	1601 BRYAN ST	DALLAS	TX	752013430	TX-TCEQ ACR
OWN	4975 DEMOSS RD	READING	PA	19606-9060	TX-TCEQ ACR
MAILING ADDRESS	500 N AKARD ST STE 9-110C	DALLAS	TX	752013302	TX-TCEQ ACR
OWN	3015 STATE ROAD	CROYDON	PA	19021-6997	TX-TCEQ ACR
OPERATOR	1601 BRYAN ST	DALLAS	TX	752013430	TX-TCEQ ACR
OWNER	1601 BRYAN ST	DALLAS	TX	752013430	TX-TCEQ ACR
OWN	FAIRLANE & DEMOSS RD	READING	PA	19606	TX-TCEQ ACR

Contacts

Affiliation Type	Full Name	Office Phone	Information System	Mailing Address
OWN	UNKNOWN	6107795660	TX-TCEQ ACR	View
OWN	UNKNOWN	2157853000	TX-TCEQ ACR	View
OWN	LAWRENCE L DROGO	6107794550	TX-TCEQ ACR	View

Query executed on: FEB-04-2010

Facility Detail Report

FRS

Report an Error

TXI OPERATIONS LP

2 MILES N. OF STREETMAN ON I-45 SERVICE RD.
STREETMAN, TX 75859
EPA Registry Id: 110008060187

Legend

★ Selected Facility
■ EPA Facility of Interest
■ State/Tribe Facility of Interest

The facility locations displayed come from the FRS Spatial Coordinates tables. They are the best representative locations for the displayed facilities based on the accuracy of the collection method and quality assurance checks performed against each location. The North American Datum of 1983 is used to display all coordinates.

Environmental Interests

Information System	Information System ID	Environmental Interest Type	Data Source	Last Updated Date	Supplemental Environmental Interests:
AIR FACILITY SYSTEM	4834900011	AIR MAJOR ()	AIRS/AFS	07/22/2009	
NATIONAL EMISSIONS INVENTORY	NEI6591	CRITERIA AND HAZARDOUS AIR POLLUTANT INVENTORY	NEI		
NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (ICIS-NPDES)	TX0047791	ICIS-NPDES NON-MAJOR	ICIS	08/20/2009	ICIS-ENFORCEMENT/COMPLIANCE ACTIVITY
PERMIT COMPLIANCE SYSTEM	TX0047791	NPDES NON-MAJOR	NPDES PERMIT	05/21/2007	
RESOURCE CONSERVATION AND RECOVERY ACT INFORMATION SYSTEM	TXD981607427	UNSPECIFIED UNIVERSE (INACTIVE)	RCRAINFO	03/07/2007	
TOXIC RELEASE INVENTORY SYSTEM	75859TXPSL2MILE	TRI REPORTER	TRI REPORTING FORM	06/09/2009	

Additional EPA Reports: MyEnvironment Enforcement and Compliance Site Demographics Watershed Report

Standard Industrial Classification Codes (SIC)

Data Source	SIC Code	Description	Primary
TRIS	3295	MINERALS AND EARTHS, GROUND OR OTHERWISE TREATED	
NEI	3295	MINERALS AND EARTHS, GROUND OR OTHERWISE TREATED	
PCS	3295	MINERALS AND EARTHS, GROUND OR OTHERWISE TREATED	
		MINERALS AND EARTHS, GROUND OR OTHERWISE	

National Industry Classification System Codes (NAICS)

Data Source	NAICS Code	Description	Primary
RCRAINFO	327992	GROUND OR TREATED MINERAL AND EARTH MANUFACTURING.	
TRIS	212324	KAOLIN AND BALL CLAY MINING.	
NEI	327992	GROUND OR TREATED MINERAL AND EARTH MANUFACTURING.	
TRIS	327992	GROUND OR TREATED MINERAL AND EARTH MANUFACTURING.	

NPDES	3295	TREATED	
AIRS/AFS	3295	MINERALS AND EARTHS, GROUND OR OTHERWISE TREATED	
FRS	3295	MINERALS AND EARTHS, GROUND OR OTHERWISE TREATED	

Facility Codes and Flags

EPA Region:	06
Duns Number:	
Congressional District Number:	24
Legislative District Number:	09
HUC Code/Watershed:	12030201 / LOWER TRINITY-TEHUACANA
US Mexico Border Indicator:	NO
Federal Facility:	
Tribal Land:	NO

Alternative Names

Alternative Name	Source of Data
TEXAS INDUSTRIES INCORPORATED	AIRS/AFS
TXI OPERATIONS, L.P.	NPDES PERMIT
TXI OPS. L.P. STREETMAN ES&C	TRI REPORTING FORM
TXI OPS. L.P. EXPANDED SHALE & CLAY PRODS.	TRIS
TXI - STREETMAN PLANT	AIRS/AFS
STREETMAN EXPANDED SHALE & CLA	NPDES PERMIT

Organizations

Affiliation Type	Name	DUNS Number	Information System	Mailing Address
OWNER	TXI OPERATIONS LP		RCRAINFO	View
OWNER	TXI OPERATIONS LP		RCRAINFO	View
OWNER	TXI OPERATIONS LP		PCS	View
OPERATOR	TXI OPERATIONS LP		RCRAINFO	View
OWNER/OPERATOR		037959673	AIRS/AFS	
OWNER	TXI OPERATIONS LP		NPDES	View
OPERATOR	TXI OPERATIONS LP		RCRAINFO	View
MAILING ADDRESS	TXI OPERATIONS LP		NPDES	View
OWNER/OPERATOR		037959673	TRIS	
OWNER	TXI OPERATIONS LP		PCS	View
PARENT ORGANIZATION	TEXAS INDUSTRIES INC.	041083403	TRIS	

Facility Mailing Addresses

Affiliation Type	Delivery Point	City Name	State	Postal Code	Information System
FACILITY MAILING ADDRESS	PO BOX 217	STREETMAN	TX	75859	TRIS
OWNER	PO BOX 217	STREETMAN	TX	75859	NPDES
REGULATORY CONTACT	245 WARD RD	MIDLOTHIAN	TX	76065	RCRAINFO
OWNER	PO BOX 217	STREETMAN	TX	75859	PCS
OWNER	TXI STREETMAN ES&C	STREETMAN	TX	75859	PCS
FACILITY MAILING ADDRESS	245 WARD RD	MIDLOTHIAN	TX	76065	RCRAINFO
OWNER	1341 W MOCKINGBIRD LANE	DALLAS	TX	75247	RCRAINFO
COGNIZANT OFFICIAL	PO BOX 217	STREETMAN	TX	75859	NPDES
OPERATOR	1341 W MOCKINGBIRD LANE	DALLAS	TX	75247	RCRAINFO
FACILITY MAILING ADDRESS	1341 W. MOCKINGBIRD LANE	DALLAS	TX	75247	AIRS/AFS
MAILING ADDRESS	PO BOX 217	STREETMAN	TX	75859	NPDES
MAILING ADDRESS	TXI STREETMAN ES&C	STREETMAN	TX	75859	NPDES
PRIMARY MAILING ADDRESS	TXI STREETMAN ES&C	STREETMAN	TX	75859	PCS

Contacts

Affiliation Type	Full Name	Office Phone	Information System	Mailing Address
COMPLIANCE CONTACT	KERRI KERR	2146476700	AIRS/AFS	
REGULATORY CONTACT	KERRI R KERR	9726474972	RCRAINFO	View
COGNIZANT OFFICIAL	WYNNE STALLCOP	9035993000	NPDES	View
PUBLIC CONTACT	NANCY GARNETT	9726473414	TRIS	
COGNIZANT OFFICIAL	GEORGE EURE_VP ES & C	9726477040	PCS	

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Detailed Reports

PCS

Report an Error

Results are based on data extracted on JAN-20-2010

Pending migration to a new system, the data for the Permit Compliance System (PCS) will remain frozen in Envirofacts for the following states and territories as of the below listed dates:
Frozen as of June 6th, 2006: MA,NH,RI,VI,PR,DC,MD,IN,NM,UT,HI,AK,ID
Frozen as of August, 2006: AS,AT,CT,CZ,FM,GA,GB,GU,JA,MH,MP,MT,MW,NE,NI,NN,NV,NY,PA,PW,SD,SR,TT,UM
Frozen as of April 24th, 2008: IL
Frozen as of August 26th, 2008: AR,CA,CO,OK,TN,WI

Please refer to the ECHO Clean Water Act Query Screen to retrieve updated data for the states frozen in Envirofacts.

Facility

FACILITY NAME (1) :	TEXAS DEPARTMENT OF CRIMINAL J	NPDES :	TX0031577
FACILITY NAME (2) :	USTICE		
STREET 1 :	FM RD 2054/4.5 MI SW TENN COL	SIC CODE :	9223 = CORRECTIONAL INSTITUTIONS
CITY :	ANDERSON COUNTY	MAJOR / MINOR :	M = Major
COUNTY NAME :	ANDERSON	TYPE OF OWNERSHIP :	STA = STATE
STATE :	TX	INDUSTRY CLASS :	X
ZIP CODE :		ACTIVITY STATUS :	A = Active
REGION :	06	INACTIVE DATE :	
LATITUDE :	+3147190		
LONGITUDE :	-09556140	TYPE OF PERMIT ISSUED :	S = STATE
LAT/LON CODE OF ACCURACY :		PERMIT ISSUED DATE :	23-JUL-2007
LAT/LON METHOD :		PERMIT EXPIRED DATE :	01-FEB-2012
LAT/LON SCALE :		ORIGINAL PERMIT ISSUE DATE :	25-OCT-1974
LAT/LON DATUM :			
LAT/LON DESCRIPTION :			
USGS HYDRO BASIN CODE :		STREAM SEGMENT :	0170
FLOW :	2.85	MILEAGE IND :	04330
RECEIVING STREAM CLASS CODE :		FEDERAL_GRANT_IND :	
RECEIVING WATERS :	UNNAMED DITCH, CEDAR LAKE SLOUGH	FINAL LIMITS IND :	F = FINAL
PRETREATMENT CODE :			
SLUDGE INDICATOR :		SLUDGE CLASS FAC IND :	
SLUDGE RELATED PERMIT NUM :		ANNUAL DRY SLUDGE PROD :	
MAILING NAME :	TEXAS DEPT OF CRIMINAL JUSTICE		
MAILING STREET (1) :	ENVIRONMENTAL AFFAIRS OFFICE	MAILING STREET (2) :	P. O. BOX 4011
MAILING CITY :	HUNTSVILLE	MAILING STATE :	TX
MAILING ZIP CODE :	773424011		
SLUDGE COMMERCIAL HANDLER :			
SLUDGE HANDLER STREET (1) :		SLUDGE HANDLER STREET (2) :	
SLUDGE HANDLER CITY :		SLUDGE HANDLER STATE :	
SLUDGE HANDLER ZIP CODE :			
COGNIZANT OFFICIAL :	FRANK INMON, DIR FACS DIVISION	COGNIZANT OFFICIAL TEL :	936-437-7201

Permit Documents

FACILITY NAME (1) :	TEXAS DEPARTMENT OF CRIMINAL J	NPDES :	TX0031577
FACILITY NAME (2) :	USTICE		

No Permit Documents Found.

Permit Tracking

FACILITY NAME (1) :	TEXAS DEPARTMENT OF CRIMINAL J	NPDES :	TX0031577
FACILITY NAME (2) :	USTICE	PERMIT ISSUED BY :	S = STATE
PERMIT ISSUED DATE :	23-JUL-2007	ORIGINAL DATE OF ISSUE :	25-OCT-1974

PERMIT EXPIRED DATE : 01-FEB-2012

Permit Tracking Events:

EVENT CODE	EVENT DESCRIPTION	ACTUAL DATE
P5099	PERMIT EXPIRED	01-FEB-2012
P4099	PERMIT ISSUED	23-JUL-2007
P3099	DRAFT PERMIT/PUBLIC NOTICE	10-JUN-2007
P1099	APPLICATION RECEIVED	20-DEC-2006

Inspections

FACILITY NAME (1) : TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2) : USTICE

INSPECTION TYPE	DATE OF INSPECTION	INSPECTION PERFORMED BY
C = COMPLIANCE EVAL (NON-SAMPLING)	21-MAY-2008	S = STATE
S = COMPLIANCE SAMPLING	15-FEB-2006	S = STATE
S = COMPLIANCE SAMPLING	30-JUN-1993	S = STATE

Outfalls/Pipe Schedules

FACILITY NAME (1) :	TEXAS DEPARTMENT OF CRIMINAL J	**NPDES :**	TX0031577
FACILITY NAME (2) :	USTICE	**OUTFALL TYPE :**	
PIPE NUMBER :	001	**ACTIVITY STATUS:**	A = ACTIVE
REPORT DESIGNATOR :	A	**LATITUDE:**	+3146506
PIPE SET QUALIFIER :	9	**LONGITUDE :**	-09553188
INACTIVE DATE :		**LAT/LON ACCURACY :**	G = 400 METERS
INIT LIMITS START DATE :		**LAT/LON METHOD :**	A = MAP INTERPOLATION
INIT LIMITS END DATE :		**LAT/LON SCALE :**	3 = 24,000
INTERIM LIMITS START DATE :		**LAT/LON DATUM :**	2 = NAD83
INTERIM LIMITS END DATE :		**LAT/LON DESCRIPTION :**	01099
FINAL LIMITS START DATE :	01-AUG-2007	**USGS HYDRO BASIN CODE :**	
FINAL LIMITS END DATE :	01-FEB-2012	**PIPE STREAM SEGMENT :**	
INIT SUBM. DATE(EPA) :		**RECEIVING STREAM CLASS CD :**	
SUBMISSION UNITS (EPA) :		**MILEAGE INDICATOR :**	
UNITS IN EPA SUBM. PERIOD :	0	**PIPE DESCRIPTION :**	DOMESTIC FACILITY - 001
INIT SUBM. DATE (STATE) :	20-SEP-2007		
SUBMISSION UNITS (STATE) :	M = MONTHS		
UNITS IN STATE SUBM. PERIOD :	1		
INIT REPORTING DATE :	01-AUG-2007		
REPORTING UNITS :	M = MONTHS		
UNITS IN REPORTING PERIOD :	1		

FACILITY NAME (1) :	TEXAS DEPARTMENT OF CRIMINAL J	**NPDES :**	TX0031577
FACILITY NAME (2) :	USTICE	**OUTFALL TYPE :**	
PIPE NUMBER :	TX1	**ACTIVITY STATUS:**	A = ACTIVE
REPORT DESIGNATOR :	Q	**LATITUDE:**	
PIPE SET QUALIFIER :	9	**LONGITUDE :**	
INACTIVE DATE :		**LAT/LON ACCURACY :**	
INIT LIMITS START DATE :		**LAT/LON METHOD :**	
INIT LIMITS END DATE :		**LAT/LON SCALE :**	
INTERIM LIMITS START DATE :		**LAT/LON DATUM :**	
INTERIM LIMITS END DATE :		**LAT/LON DESCRIPTION :**	
FINAL LIMITS START DATE :	01-AUG-2007	**USGS HYDRO BASIN CODE :**	
FINAL LIMITS END DATE :	01-FEB-2012	**PIPE STREAM SEGMENT :**	
INIT SUBM. DATE(EPA) :		**RECEIVING STREAM CLASS CD :**	
SUBMISSION UNITS (EPA) :		**MILEAGE INDICATOR :**	
UNITS IN EPA SUBM. PERIOD :	0	**PIPE DESCRIPTION :**	7-DAY CHRONIC FRESHWATER - 001
INIT SUBM. DATE (STATE) :	20-JAN-2008		

SUBMISSION UNITS (STATE) : M = MONTHS
UNITS IN STATE SUBM. PERIOD : 3
INIT REPORTING DATE : 01-OCT-2007
REPORTING UNITS : M = MONTHS
UNITS IN REPORTING PERIOD : 3

FACILITY NAME (1) : TEXAS DEPARTMENT OF CRIMINAL J
FACILITY NAME (2) : USTICE
PIPE NUMBER : SLD
REPORT DESIGNATOR : F
PIPE SET QUALIFIER : 9
INACTIVE DATE :
INIT LIMITS START DATE :
INIT LIMITS END DATE :
INTERIM LIMITS START DATE :
INTERIM LIMITS END DATE :
FINAL LIMITS START DATE : 01-AUG-2007
FINAL LIMITS END DATE : 01-FEB-2012
INIT SUBM. DATE(EPA) :
SUBMISSION UNITS (EPA) :
UNITS IN EPA SUBM. PERIOD : 0
INIT SUBM. DATE (STATE) : 01-SEP-2008
SUBMISSION UNITS (STATE) : M = MONTHS
UNITS IN STATE SUBM. PERIOD : 12
INIT REPORTING DATE : 01-AUG-2007
REPORTING UNITS : M = MONTHS
UNITS IN REPORTING PERIOD : 12

NPDES : TX0031577
OUTFALL TYPE : S = SLUDGE
ACTIVITY STATUS: A = ACTIVE
LATITUDE:
LONGITUDE :
LAT/LON ACCURACY :
LAT/LON METHOD :
LAT/LON SCALE :
LAT/LON DATUM :
LAT/LON DESCRIPTION :
USGS HYDRO BASIN CODE :
PIPE STREAM SEGMENT :
RECEIVING STREAM CLASS CD :
MILEAGE INDICATOR :
PIPE DESCRIPTION : LANDFILL- SLDF

FACILITY NAME (1) : TEXAS DEPARTMENT OF CRIMINAL J
FACILITY NAME (2) : USTICE
PIPE NUMBER : SLS
REPORT DESIGNATOR : A
PIPE SET QUALIFIER : 9
INACTIVE DATE :
INIT LIMITS START DATE :
INIT LIMITS END DATE :
INTERIM LIMITS START DATE :
INTERIM LIMITS END DATE :
FINAL LIMITS START DATE : 01-AUG-2007
FINAL LIMITS END DATE : 01-FEB-2012
INIT SUBM. DATE(EPA) :
SUBMISSION UNITS (EPA) :
UNITS IN EPA SUBM. PERIOD : 0
INIT SUBM. DATE (STATE) : 01-SEP-2008
SUBMISSION UNITS (STATE) : M = MONTHS
UNITS IN STATE SUBM. PERIOD : 12
INIT REPORTING DATE : 01-AUG-2007
REPORTING UNITS : M = MONTHS
UNITS IN REPORTING PERIOD : 12

NPDES : TX0031577
OUTFALL TYPE : S = SLUDGE
ACTIVITY STATUS: A = ACTIVE
LATITUDE:
LONGITUDE :
LAT/LON ACCURACY :
LAT/LON METHOD :
LAT/LON SCALE :
LAT/LON DATUM :
LAT/LON DESCRIPTION :
USGS HYDRO BASIN CODE :
PIPE STREAM SEGMENT :
RECEIVING STREAM CLASS CD :
MILEAGE INDICATOR :
PIPE DESCRIPTION : SURFACE DISPOSAL-SLSA

FACILITY NAME (1) : TEXAS DEPARTMENT OF CRIMINAL J
FACILITY NAME (2) : USTICE
PIPE NUMBER : TXA
REPORT DESIGNATOR : S
PIPE SET QUALIFIER : 9
INACTIVE DATE :
INIT LIMITS START DATE :
INIT LIMITS END DATE :
INTERIM LIMITS START DATE :
INTERIM LIMITS END DATE :

NPDES : TX0031577
OUTFALL TYPE :
ACTIVITY STATUS: A = ACTIVE
LATITUDE:
LONGITUDE :
LAT/LON ACCURACY :
LAT/LON METHOD :
LAT/LON SCALE :
LAT/LON DATUM :
LAT/LON DESCRIPTION :

FINAL LIMITS START DATE :	01-AUG-2007	USGS HYDRO BASIN CODE :	
FINAL LIMITS END DATE :	01-FEB-2012	PIPE STREAM SEGMENT :	
INIT SUBM. DATE(EPA) :		RECEIVING STREAM CLASS CD :	
SUBMISSION UNITS (EPA) :		MILEAGE INDICATOR :	
UNITS IN EPA SUBM. PERIOD :	0	PIPE DESCRIPTION :	24-HOUR ACUTE FRESHWATER - 001
INIT SUBM. DATE (STATE) :	20-JUL-2008		
SUBMISSION UNITS (STATE) :	M = MONTHS		
UNITS IN STATE SUBM. PERIOD :	6		
INIT REPORTING DATE :	01-JAN-2008		
REPORTING UNITS :	M = MONTHS		
UNITS IN REPORTING PERIOD :	6		

FACILITY NAME (1) :	TEXAS DEPARTMENT OF CRIMINAL J	NPDES :	TX0031577
FACILITY NAME (2) :	USTICE	OUTFALL TYPE :	S = SLUDGE
PIPE NUMBER :	SLD	ACTIVITY STATUS:	A = ACTIVE
REPORT DESIGNATOR :	P	LATITUDE:	
PIPE SET QUALIFIER :	9	LONGITUDE :	
INACTIVE DATE :		LAT/LON ACCURACY :	
INIT LIMITS START DATE :		LAT/LON METHOD :	
INIT LIMITS END DATE :		LAT/LON SCALE :	
INTERIM LIMITS START DATE :		LAT/LON DATUM :	
INTERIM LIMITS END DATE :		LAT/LON DESCRIPTION :	
FINAL LIMITS START DATE :	01-AUG-2007	USGS HYDRO BASIN CODE :	
FINAL LIMITS END DATE :	01-FEB-2012	PIPE STREAM SEGMENT :	
INIT SUBM. DATE(EPA) :		RECEIVING STREAM CLASS CD :	
SUBMISSION UNITS (EPA) :		MILEAGE INDICATOR :	
UNITS IN EPA SUBM. PERIOD :	0	PIPE DESCRIPTION :	PRODUCTION AND USE - SLDP
INIT SUBM. DATE (STATE) :	01-SEP-2008		
SUBMISSION UNITS (STATE) :	M = MONTHS		
UNITS IN STATE SUBM. PERIOD :	12		
INIT REPORTING DATE :	01-AUG-2007		
REPORTING UNITS :	M = MONTHS		
UNITS IN REPORTING PERIOD :	12		

FACILITY NAME (1) :	TEXAS DEPARTMENT OF CRIMINAL J	NPDES :	TX0031577
FACILITY NAME (2) :	USTICE	OUTFALL TYPE :	S = SLUDGE
PIPE NUMBER :	SLL	ACTIVITY STATUS:	A = ACTIVE
REPORT DESIGNATOR :	A	LATITUDE:	
PIPE SET QUALIFIER :	9	LONGITUDE :	
INACTIVE DATE :		LAT/LON ACCURACY :	
INIT LIMITS START DATE :		LAT/LON METHOD :	
INIT LIMITS END DATE :		LAT/LON SCALE :	
INTERIM LIMITS START DATE :		LAT/LON DATUM :	
INTERIM LIMITS END DATE :		LAT/LON DESCRIPTION :	
FINAL LIMITS START DATE :	01-AUG-2007	USGS HYDRO BASIN CODE :	
FINAL LIMITS END DATE :	01-FEB-2012	PIPE STREAM SEGMENT :	
INIT SUBM. DATE(EPA) :		RECEIVING STREAM CLASS CD :	
SUBMISSION UNITS (EPA) :		MILEAGE INDICATOR :	
UNITS IN EPA SUBM. PERIOD :	0	PIPE DESCRIPTION :	LAND APPLICATION - SLLA
INIT SUBM. DATE (STATE) :	01-SEP-2008		
SUBMISSION UNITS (STATE) :	M = MONTHS		
UNITS IN STATE SUBM. PERIOD :	12		
INIT REPORTING DATE :	01-AUG-2007		
REPORTING UNITS :	M = MONTHS		
UNITS IN REPORTING PERIOD :	12		

FACILITY NAME (1) :	TEXAS DEPARTMENT OF CRIMINAL J	NPDES :	TX0031577
FACILITY NAME (2) :	USTICE	OUTFALL TYPE :	S = SLUDGE
PIPE NUMBER :	SLL	ACTIVITY STATUS:	A = ACTIVE
REPORT DESIGNATOR :	Y	LATITUDE:	

PIPE SET QUALIFIER : 9
INACTIVE DATE :
INIT LIMITS START DATE :
INIT LIMITS END DATE :
INTERIM LIMITS START DATE :
INTERIM LIMITS END DATE :
FINAL LIMITS START DATE : 01-AUG-2007
FINAL LIMITS END DATE : 01-FEB-2012
INIT SUBM. DATE(EPA) :
SUBMISSION UNITS (EPA) :
UNITS IN EPA SUBM. PERIOD : 0
INIT SUBM. DATE (STATE) : 01-SEP-2008
SUBMISSION UNITS (STATE) : M = MONTHS
UNITS IN STATE SUBM. PERIOD : 12
INIT REPORTING DATE : 01-AUG-2007
REPORTING UNITS : M = MONTHS
UNITS IN REPORTING PERIOD : 12

LONGITUDE :
LAT/LON ACCURACY :
LAT/LON METHOD :
LAT/LON SCALE :
LAT/LON DATUM :
LAT/LON DESCRIPTION :
USGS HYDRO BASIN CODE :
PIPE STREAM SEGMENT :
RECEIVING STREAM CLASS CD :
MILEAGE INDICATOR :
PIPE DESCRIPTION : SECTION I, C - SLLY

Limits Report

FACILITY NAME (1) : TEXAS DEPARTMENT OF CRIMINAL J
FACILITY NAME (2) : USTICE
REPORT DESIGNATOR : A
NPDES : TX0031577
PIPE NUMBER : 001
PIPE SET QUALIFIER : 9

LIMIT TYPE	PARAMETER CODE	MONITORING LOCATION	SEASON NUM	MODIFICATION NUM	MOD. PERIOD START DATE	MOD. PERIOD END DATE	CHANGE OF LIMIT STATUS	CONTESTED PARAMETER INDICATOR	DOCKET NUMBER	LONG FORMAT
5 = FINAL	OXYGEN, DISSOLVED (DO)	1 = EFFLUENT GROSS VALUE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	PH	1 = EFFLUENT GROSS VALUE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	SOLIDS, TOTAL SUSPENDED	1 = EFFLUENT GROSS VALUE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	NITROGEN, AMMONIA TOTAL (AS N)	1 = EFFLUENT GROSS VALUE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	BOD, CARBONACEOUS 05 DAY, 20C	1 = EFFLUENT GROSS VALUE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	FLOW, IN CONDUIT OR THRU TREATMENT PLANT	P = SEE COMMENTS BELOW	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	FLOW, IN CONDUIT OR THRU TREATMENT PLANT	Y = ANNUAL AVERAGE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	CHLORINE, TOTAL RESIDUAL	A = DISINFECT,PRCS CMPLT	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	CHLORINE, TOTAL RESIDUAL	B = PRIOR TO DISINFECT	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	FLOW, IN CONDUIT OR THRU TREATMENT PLANT	1 = EFFLUENT GROSS VALUE	0	0	01-AUG-2007	01-FEB-2012				YES

FACILITY NAME (1) : TEXAS DEPARTMENT OF CRIMINAL J
FACILITY NAME (2) : USTICE
REPORT DESIGNATOR : P
NPDES : TX0031577
PIPE NUMBER : SLD
PIPE SET QUALIFIER : 9

LIMIT TYPE	PARAMETER CODE	MONITORING LOCATION	SEASON NUM	MODIFICATION NUM	MOD. PERIOD START DATE	MOD. PERIOD END DATE	CHANGE OF LIMIT STATUS	CONTESTED PARAMETER INDICATOR	DOCKET NUMBER	LONG FORMAT
5 = FINAL	POLYCHLORINATED BIPHENYLS (PCBS)	+ = SLUDGE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	TOXICITY CHARACTERISTIC LEACHING PROCED.	+ = SLUDGE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	ANN. AMT SLUDGE DISPOSED BY OTHER METHOD	V = SEE COMMENTS BELOW	0	0	01-AUG-2007	01-FEB-2012				YES

5 = FINAL	ANNUAL AMT OF SLUDGEINCINERATED	+ = SLUDGE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	ANNUAL AMT SLUDGE TRANSPORTED INTERSTATE	+ = SLUDGE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	ANNUAL AMOUNT OF SLUDGE LAND APPLIED	+ = SLUDGE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	ANNUAL AMT. SLUDGE DISPOSED SURFACE UNIT	+ = SLUDGE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	ANNUAL AMT SLUDGE DISPOSED IN LANDFILL	+ = SLUDGE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	ANNUAL SLUDGE PRODUCTION, TOTAL	+ = SLUDGE	0	0	01-AUG-2007	01-FEB-2012				YES

FACILITY NAME (1) : TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2) : USTICE **PIPE NUMBER :** SLS
REPORT DESIGNATOR : A **PIPE SET QUALIFIER :** 9

LIMIT TYPE	PARAMETER CODE	MONITORING LOCATION	SEASON NUM	MODIFICATION NUM	MOD. PERIOD START DATE	MOD. PERIOD END DATE	CHANGE OF LIMIT STATUS	CONTESTED PARAMETER INDICATOR	DOCKET NUMBER	LONG FORMAT
5 = FINAL	PH	+ = SLUDGE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	ARSENIC IN BOTTOM DEPOSITS (DRY WGT)	+ = SLUDGE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	NICKEL, TOTAL (AS NI)	+ = SLUDGE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	VECTOR ATTRACTION REDUCTION ALTERN USED	+ = SLUDGE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	CHROMIUM, SLUDGE, TOT, DRY WT. (AS CR)	+ = SLUDGE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	LEVEL OF PATHOGEN REQUIREMENTS ACHIEVED	T = SEE COMMENTS BELOW	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	DESCRIPTION OF PATHOGEN OPTION USED	+ = SLUDGE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	UNIT W/LINER/LEACHATE COLLECTION SYSTEM	+ = SLUDGE	0	0	01-AUG-2007	01-FEB-2012				YES

FACILITY NAME (1) : TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2) : USTICE **PIPE NUMBER :** TX1
REPORT DESIGNATOR : Q **PIPE SET QUALIFIER :** 9

LIMIT TYPE	PARAMETER CODE	MONITORING LOCATION	SEASON NUM	MODIFICATION NUM	MOD. PERIOD START DATE	MOD. PERIOD END DATE	CHANGE OF LIMIT STATUS	CONTESTED PARAMETER INDICATOR	DOCKET NUMBER	LONG FORMAT
5 = FINAL	LF P/F LETH STATRE 7DAY CHR CERIODAPHNIA	1 = EFFLUENT GROSS VALUE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	LF P/F LETH STATRE 7DAY CHR PIMEPHALES	1 = EFFLUENT GROSS VALUE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	NOEL SUB-LTH STATRE 7DAY CHR PIMEPHALES	1 = EFFLUENT GROSS VALUE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	NOEL LETHAL STATRE 7DAY CHR PIMEPHALES	1 = EFFLUENT GROSS VALUE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	NOEL SUB-LTH STATRE 7DAY CHR CERIODAPHNIA	1 = EFFLUENT GROSS VALUE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	NOEL LETHAL STATRE 7DAY CHR CERIODAPHNIA	1 = EFFLUENT GROSS VALUE	0	0	01-AUG-2007	01-FEB-2012				YES

FACILITY NAME (1) : TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2) : USTICE **PIPE NUMBER :** SLL
REPORT DESIGNATOR : A **PIPE SET QUALIFIER :** 9

LIMIT TYPE	PARAMETER CODE	MONITORING LOCATION	SEASON NUM	MODIFICATION NUM	MOD. PERIOD START DATE	MOD. PERIOD END DATE	CHANGE OF LIMIT STATUS	CONTESTED PARAMETER INDICATOR	DOCKET NUMBER	LONG FORMAT
5 =	ARSENIC IN BOTTOM DEPOSITS	R = SEE								

FINAL	(DRY WGT)	COMMENTS BELOW	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	VECTOR ATTRACTION REDUCTION ALTERN USED	+ = SLUDGE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	COPPER, TOTAL SLUDGE	R = SEE COMMENTS BELOW	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	CADIUM, TOTAL SLUDGE	R = SEE COMMENTS BELOW	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	ANNUAL WHOLE SLUDGE APPLICATION RATE	P = SEE COMMENTS BELOW	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	MOLYBDENUM, SLUDGE, TOT, DRY WT. (AS MO)	R = SEE COMMENTS BELOW	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	ZINC, SLUDGE, TOTAL, DRY WEIGHT, (AS ZN)	R = SEE COMMENTS BELOW	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	LEAD, SLUDGE, TOTAL, DRY WEIGHT (AS PB)	R = SEE COMMENTS BELOW	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	NICKEL, SLUDGE, TOT, DRY WEIGHT (AS NI)	R = SEE COMMENTS BELOW	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	MERCURY, SLUDGE, TOT DRY WEIGHT (AS HG)	R = SEE COMMENTS BELOW	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	CHROMIUM, SLUDGE, TOT, DRY WT. (AS CR)	R = SEE COMMENTS BELOW	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	POLLUTANT TABLE FROM 503.13	S = SEE COMMENTS BELOW	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	LEVEL OF PATHOGEN REQUIREMENTS ACHIEVED	T = SEE COMMENTS BELOW	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	DESCRIPTION OF PATHOGEN OPTION USED	+ = SLUDGE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	SELENIUM IN BOTTOM DEPOSITS (DRY WGT)	R = SEE COMMENTS BELOW	0	0	01-AUG-2007	01-FEB-2012				YES

FACILITY NAME (1) : TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2) : USTICE **PIPE NUMBER :** SLD
REPORT DESIGNATOR : F **PIPE SET QUALIFIER :** 9

LIMIT TYPE	PARAMETER CODE	MONITORING LOCATION	SEASON NUM	MODIFICATION NUM	MOD. PERIOD START DATE	MOD. PERIOD END DATE	CHANGE OF LIMIT STATUS	CONTESTED PARAMETER INDICATOR	DOCKET NUMBER	LONG FORMAT
5 = FINAL	COMPLIANCE W/PART 258 SLUDGE REQUIREMENT	+ = SLUDGE	0	0	01-AUG-2007	01-FEB-2012				YES

FACILITY NAME (1) : TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2) : USTICE **PIPE NUMBER :** TXA
REPORT DESIGNATOR : S **PIPE SET QUALIFIER :** 9

LIMIT TYPE	PARAMETER CODE	MONITORING LOCATION	SEASON NUM	MODIFICATION NUM	MOD. PERIOD START DATE	MOD. PERIOD END DATE	CHANGE OF LIMIT STATUS	CONTESTED PARAMETER INDICATOR	DOCKET NUMBER	LONG FORMAT
5 = FINAL	LC50/PF STAT 24HR ACU PIMPHALES	1 = EFFLUENT GROSS VALUE	0	0	01-AUG-2007	01-FEB-2012				YES
5 = FINAL	LC50/PF STAT 24HR ACU D. PULEX	1 = EFFLUENT GROSS VALUE	0	0	01-AUG-2007	01-FEB-2012				YES

Measurements and Violations

FACILITY NAME (1):	TEXAS DEPARTMENT OF CRIMINAL J	**NPDES :**	TX0031577
FACILITY NAME (2):	USTICE	**LIMIT TYPE :**	5 = FINAL
PIPE NUMBER :	001	**SEASON NUM :**	0
REPORT DESIGNATOR :	A	**PARAMETER CODE:**	00300 = OXYGEN, DISSOLVED (DO)
PIPE SET QUALIFIER :	9	**MONITORING LOCATION :**	1 = EFFLUENT GROSS VALUE
MODIFICATION NUM :	0		

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-MAY-2009						4.46					E90 = NUMERIC VIOLATION NUMERIC VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
30-APR-2009						5.40					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-MAR-2009						5.40					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
28-FEB-2009						5.70					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-JAN-2009						6.0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-DEC-2008						5.36					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
30-NOV-2008						7.50					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-OCT-2008						6.00					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
30-SEP-2008						6.0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-AUG-2008						5.00					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-JUL-2008						5.40					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
30-JUN-2008						6.43					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER

31-MAY-2008						5.42					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
30-APR-2008						5.51					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-MAR-2008						6.00					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
29-FEB-2008						7.36					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-JAN-2008						6.90					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-DEC-2007						7.60					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
30-NOV-2007						6.50					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-OCT-2007						5.8					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
30-SEP-2007						5.90					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-AUG-2007						5.70					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER

FACILITY NAME (1):	TEXAS DEPARTMENT OF CRIMINAL J	NPDES :	TX0031577
FACILITY NAME (2):	USTICE	LIMIT TYPE :	5 = FINAL
PIPE NUMBER :	001	SEASON NUM :	0
REPORT DESIGNATOR :	A	PARAMETER CODE:	00400 = PH
PIPE SET QUALIFIER :	9	MONITORING LOCATION :	1 = EFFLUENT GROSS VALUE
MODIFICATION NUM :	0		

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-MAY-2009				7.70		7.10					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		12 = SU SU STANDARD UNITS (I.E. PH)
											E00 = MEASUREMENT		12 = SU SU

30-APR-2009				7.40		7.00					ONLY, NO VIOLATION NO VIOL		STANDARD UNITS (I.E. PH)
31-MAR-2009				7.60		7.20					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		12 = SU SU STANDARD UNITS (I.E. PH)
28-FEB-2009				8.20		7.40					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		12 = SU SU STANDARD UNITS (I.E. PH)
31-JAN-2009				7.8		7.3					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		12 = SU SU STANDARD UNITS (I.E. PH)
31-DEC-2008				7.84		7.10					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		12 = SU SU STANDARD UNITS (I.E. PH)
30-NOV-2008				8.30		6.99					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		12 = SU SU STANDARD UNITS (I.E. PH)
31-OCT-2008				7.90		7.25					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		12 = SU SU STANDARD UNITS (I.E. PH)
30-SEP-2008				7.9		7.1					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		12 = SU SU STANDARD UNITS (I.E. PH)
31-AUG-2008				8.40		7.20					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		12 = SU SU STANDARD UNITS (I.E. PH)
31-JUL-2008				8.60		7.20					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		12 = SU SU STANDARD UNITS (I.E. PH)
30-JUN-2008				8.15		7.32					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		12 = SU SU STANDARD UNITS (I.E. PH)
31-MAY-2008				8.35		7.50					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		12 = SU SU STANDARD UNITS (I.E. PH)
30-APR-2008				8.00		7.10					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		12 = SU SU STANDARD UNITS (I.E. PH)
31-MAR-2008				8.04		7.37					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		12 = SU SU STANDARD UNITS (I.E. PH)

29-FEB-2008				7.93		7.30					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		12 = SU SU STANDARD UNITS (I.E. PH)
31-JAN-2008				8.60		7.60					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		12 = SU SU STANDARD UNITS (I.E. PH)
31-DEC-2007				8.00		7.30					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		12 = SU SU STANDARD UNITS (I.E. PH)
30-NOV-2007				8.30		7.70					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		12 = SU SU STANDARD UNITS (I.E. PH)
31-OCT-2007				7.7		7.3					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		12 = SU SU STANDARD UNITS (I.E. PH)
30-SEP-2007				7.80		7.20					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		12 = SU SU STANDARD UNITS (I.E. PH)
31-AUG-2007				7.80		7.30					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		12 = SU SU STANDARD UNITS (I.E. PH)

FACILITY NAME (1):	TEXAS DEPARTMENT OF CRIMINAL J	**NPDES :**	TX0031577
FACILITY NAME (2):	USTICE	**LIMIT TYPE :**	5 = FINAL
PIPE NUMBER :	001	**SEASON NUM :**	0
REPORT DESIGNATOR :	A	**PARAMETER CODE:**	00530 = SOLIDS, TOTAL SUSPENDED
PIPE SET QUALIFIER :	9	**MONITORING LOCATION :**	1 = EFFLUENT GROSS VALUE
MODIFICATION NUM :	0		

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-MAY-2009			53.20	12.60	4.68						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
30-APR-2009			28.79	3.10	2.09						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-MAR-2009			35.14	3.30	1.96						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
28-FEB-2009			32.49	5.10	1.99						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
											E00 = MEASUREMENT	26 = LBS/DYLBS/DAY	19 = MG/L MG/L

31-JAN-2009			76.34	13.7	4.66						ONLY, NO VIOLATION NO VIOL	POUNDS PER DAY	MILLIGRAMS PER LITER
31-DEC-2008			79.05	12.00	5.48						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
30-NOV-2008			42.99	4.90	2.83						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-OCT-2008			40.19	3.40	2.75						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
30-SEP-2008			24.9	2.8	1.55						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-AUG-2008			47.00	5.20	2.87						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-JUL-2008			54.85	7.60	3.53						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
30-JUN-2008			56.43	4.80	3.45						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-MAY-2008			99.43	10.60	6.27						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
30-APR-2008			61.11	6.60	3.89						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-MAR-2008			60.29	4.80	3.98						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
29-FEB-2008			81.95	13.60	5.40						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-JAN-2008			167.24	28.40	10.76						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-DEC-2007			181.63	22.00	10.56						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER

30-NOV-2007			91.57	6.80	5.18						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-OCT-2007			179.85	24.8	10.59						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
30-SEP-2007			195.76	27.70	10.83						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-AUG-2007			190.21	20.00	10.69						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
NPDES : TX0031577
FACILITY NAME (2): USTICE
LIMIT TYPE : 5 = FINAL
PIPE NUMBER : 001
SEASON NUM : 0
REPORT DESIGNATOR : A
PARAMETER CODE: 00610 = NITROGEN, AMMONIA TOTAL (AS N)
PIPE SET QUALIFIER : 9
MONITORING LOCATION : 1 = EFFLUENT GROSS VALUE
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-MAY-2009			< 1.87	0.66	< 0.16						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
30-APR-2009			1.43	0.10	0.10						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-MAR-2009			1.78	0.10	0.10						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
28-FEB-2009			1.63	0.10	0.10						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-JAN-2009			2.18	0.44	0.13						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-DEC-2008			1.46	0.10	0.10						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
30-NOV-2008			1.89	.30	.13						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
											E00 = MEASUREMENT	26 = LBS/DYLBS/DAY	19 = MG/L MG/L

31-OCT-2008			1.54	.16	.11						ONLY, NO VIOLATION NO VIOL	POUNDS PER DAY	MILLIGRAMS PER LITER
30-SEP-2008			1.67	.12	.1						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-AUG-2008			1.63	.10	.10						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-JUL-2008			1.72	.20	.11						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
30-JUN-2008			1.63	.10	.10						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-MAY-2008			1.69	.16	.11						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
30-APR-2008			3.27	.73	.21						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-MAR-2008			1.61	.14	.11						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
29-FEB-2008			1.90	.22	.13						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-JAN-2008			3.31	1.10	.21						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-DEC-2007			1.85	.16	.11						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
30-NOV-2007			1.77	.10	.10						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-OCT-2007			1.69	0.1	0.1						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
30-SEP-2007			3.86	.76	.21						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER

31-AUG-2007			1.76	.11	.10						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
FACILITY NAME (2): USTICE
PIPE NUMBER : 001
REPORT DESIGNATOR : A
PIPE SET QUALIFIER : 9
MODIFICATION NUM : 0

NPDES : TX0031577
LIMIT TYPE : 5 = FINAL
SEASON NUM : 0
PARAMETER CODE: 50050 = FLOW, IN CONDUIT OR THRU TREATMENT PLANT
MONITORING LOCATION : 1 = EFFLUENT GROSS VALUE

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-MAY-2009		1.501000	1.380000								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
30-APR-2009		2.144	1.845								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
31-MAR-2009		2.268	2.014								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
28-FEB-2009		2.059	1.951								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
31-JAN-2009		2.076	1.940								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
31-DEC-2008		1.96	1.78								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
30-NOV-2008		2.021	1.809								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
31-OCT-2008		2.080	1.811								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
30-SEP-2008		2.091	1.928								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
31-AUG-2008		2097	1.950								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
											E00 = MEASUREMENT	03 = MGD MGD	

31-JUL-2008		2.047	1.852								ONLY, NO VIOLATION NO VIOL	MILLION GALLONS PER DAY	
30-JUN-2008		2.664	1.964								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
31-MAY-2008		2.016	1.883								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
30-APR-2008		1.972	1.851								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
31-MAR-2008		2.000	1.776								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
29-FEB-2008		1.915	1.814								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
31-JAN-2008		2.117	1.838								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
31-DEC-2007		2.370	2.066								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
30-NOV-2007		2.206	2.093								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
31-OCT-2007		2.355	2.028								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
30-SEP-2007		2.328	2.154								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
31-AUG-2007		2.328	2.108								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	

FACILITY NAME (1):	TEXAS DEPARTMENT OF CRIMINAL J	**NPDES :**	TX0031577
FACILITY NAME (2):	USTICE	**LIMIT TYPE :**	5 = FINAL
PIPE NUMBER :	001	**SEASON NUM :**	0
REPORT DESIGNATOR :	A	**PARAMETER CODE:**	50050 = FLOW, IN CONDUIT OR THRU TREATMENT PLANT
PIPE SET QUALIFIER :	9	**MONITORING LOCATION :**	P = SEE COMMENTS BELOW
MODIFICATION NUM :	0		

MONITORING PERIOD END	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION	RNC DETECTION	RNC RESOLUTION	RNC RESOLUTION	MEASUREMENT VIOLATION	QUANTITY UNIT	CONCENTRATION UNIT CODE

DATE							CODE	DATE	CODE	DATE	CODE	CODE	
31-MAY-2009		937									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	78 = GPM GPM GALLONS PER MINUTE	
30-APR-2009		2187									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	78 = GPM GPM GALLONS PER MINUTE	
31-MAR-2009		2430									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	78 = GPM GPM GALLONS PER MINUTE	
28-FEB-2009		1840									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	78 = GPM GPM GALLONS PER MINUTE	
31-JAN-2009		1701									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	78 = GPM GPM GALLONS PER MINUTE	
31-DEC-2008		1909									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	78 = GPM GPM GALLONS PER MINUTE	
30-NOV-2008		1597									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	78 = GPM GPM GALLONS PER MINUTE	
31-OCT-2008		1805									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	78 = GPM GPM GALLONS PER MINUTE	
30-SEP-2008		1666									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	78 = GPM GPM GALLONS PER MINUTE	
31-AUG-2008		1701									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	78 = GPM GPM GALLONS PER MINUTE	
31-JUL-2008		1666									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	78 = GPM GPM GALLONS PER MINUTE	
30-JUN-2008		1909									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	78 = GPM GPM GALLONS PER MINUTE	
31-MAY-2008		1736									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	78 = GPM GPM GALLONS PER MINUTE	
											E00 = MEASUREMENT	78 = GPM GPM	

30-APR-2008		1736									ONLY, NO VIOLATION NO VIOL	GALLONS PER MINUTE	
31-MAR-2008		1805									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	78 = GPM GPM GALLONS PER MINUTE	
29-FEB-2008		1666									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	78 = GPM GPM GALLONS PER MINUTE	
31-JAN-2008		2187									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	78 = GPM GPM GALLONS PER MINUTE	
31-DEC-2007		1910									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	78 = GPM GPM GALLONS PER MINUTE	
30-NOV-2007		1909									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	78 = GPM GPM GALLONS PER MINUTE	
31-OCT-2007		2083									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	78 = GPM GPM GALLONS PER MINUTE	
30-SEP-2007		2361									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	78 = GPM GPM GALLONS PER MINUTE	
31-AUG-2007		1997									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	78 = GPM GPM GALLONS PER MINUTE	

FACILITY NAME (1):	TEXAS DEPARTMENT OF CRIMINAL J	**NPDES :**	TX0031577
FACILITY NAME (2):	USTICE	**LIMIT TYPE :**	5 = FINAL
PIPE NUMBER :	001	**SEASON NUM :**	0
REPORT DESIGNATOR :	A	**PARAMETER CODE:**	50050 = FLOW, IN CONDUIT OR THRU TREATMENT PLANT
PIPE SET QUALIFIER :	9	**MONITORING LOCATION :**	Y = ANNUAL AVERAGE
MODIFICATION NUM :	0		

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-MAY-2009			1.792								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
30-APR-2009			1.8938								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
31-MAR-2009			1.8943								E00 = MEASUREMENT ONLY, NO VIOLATION NO	03 = MGD MGD MILLION GALLONS	

											VIOL	PER DAY	
28-FEB-2009			1.874								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
31-JAN-2009			1.8686								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
31-DEC-2008			1.86								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
30-NOV-2008			1.8843								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
31-OCT-2008			1.907								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
30-SEP-2008			1.9261								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
31-AUG-2008			1.9447								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
31-JUL-2008			1.9581								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
30-JUN-2008			1.953								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
31-MAY-2008			1.947								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
30-APR-2008			1.9454								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
31-MAR-2008			1.926								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
29-FEB-2008			1.9613								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
											E00 = MEASUREMENT	03 = MGD MGD	

31-JAN-2008			1.9772								ONLY, NO VIOLATION NO VIOL	MILLION GALLONS PER DAY	
31-DEC-2007			2.003								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
30-NOV-2007			1.9675								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
31-OCT-2007			1.97								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
30-SEP-2007			1.98								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	
31-AUG-2007			1.985								E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	03 = MGD MGD MILLION GALLONS PER DAY	

FACILITY NAME (1):	TEXAS DEPARTMENT OF CRIMINAL J	NPDES :	TX0031577
FACILITY NAME (2):	USTICE	LIMIT TYPE :	5 = FINAL
PIPE NUMBER :	001	SEASON NUM :	0
REPORT DESIGNATOR :	A	PARAMETER CODE:	50060 = CHLORINE, TOTAL RESIDUAL
PIPE SET QUALIFIER :	9	MONITORING LOCATION :	A = DISINFECT,PRCS CMPLT
MODIFICATION NUM :	0		

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-MAY-2009				0.080							E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
30-APR-2009				.08							E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-MAR-2009				0.08							E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
28-FEB-2009				.08							E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-JAN-2009				0.080							E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-DEC-2008				.080							E00 = MEASUREMENT ONLY, NO VIOLATION NO		19 = MG/L MG/L MILLIGRAMS PER LITER

											VIOL		
30-NOV-2008				.080							E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-OCT-2008				.090							E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
30-SEP-2008				.91							E90 = NUMERIC VIOLATION NUMERIC VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-AUG-2008				.09							E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-JUL-2008				.09							E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
30-JUN-2008				.08							E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-MAY-2008				.08							E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
30-APR-2008				.09							E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-MAR-2008				.09							E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
29-FEB-2008				.09							E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-JAN-2008				.08							E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-DEC-2007				.08							E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
30-NOV-2007				.09							E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-OCT-2007				0.06							E00 = MEASUREMENT ONLY, NO VIOLATION NO		19 = MG/L MG/L MILLIGRAMS PER LITER

											VIOL		
30-SEP-2007				.08							E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-AUG-2007				.08							E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER

FACILITY NAME (1):	TEXAS DEPARTMENT OF CRIMINAL J	**NPDES :**	TX0031577
FACILITY NAME (2):	USTICE	**LIMIT TYPE :**	5 = FINAL
PIPE NUMBER :	001	**SEASON NUM :**	0
REPORT DESIGNATOR :	A	**PARAMETER CODE:**	50060 = CHLORINE, TOTAL RESIDUAL
PIPE SET QUALIFIER :	9	**MONITORING LOCATION :**	B = PRIOR TO DISINFECT
MODIFICATION NUM :	0		

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-MAY-2009						1.36					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
30-APR-2009						1.04					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-MAR-2009						1.09					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
28-FEB-2009						1.03					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-JAN-2009						1.14					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-DEC-2008						1.06					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
30-NOV-2008						1.070					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-OCT-2008						1.17					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
30-SEP-2008						.29					E90 = NUMERIC VIOLATION NUMERIC VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-AUG-2008						1.05					E00 = MEASUREMENT ONLY, NO		19 = MG/L MG/L MILLIGRAMS PER

											VIOLATION NO VIOL		LITER
31-JUL-2008						1.05					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
30-JUN-2008						1.37					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-MAY-2008						1.15					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
30-APR-2008						1.16					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-MAR-2008						1.24					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
29-FEB-2008						1.33					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-JAN-2008						1.08					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-DEC-2007						1.21					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
30-NOV-2007						1.44					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-OCT-2007						1.31					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
30-SEP-2007						1.34					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER
31-AUG-2007						1.43					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		19 = MG/L MG/L MILLIGRAMS PER LITER

FACILITY NAME (1):	TEXAS DEPARTMENT OF CRIMINAL J	**NPDES :**	TX0031577
FACILITY NAME (2):	USTICE	**LIMIT TYPE :**	5 = FINAL
PIPE NUMBER :	001	**SEASON NUM :**	0
REPORT DESIGNATOR :	A	**PARAMETER CODE:**	80082 = BOD, CARBONACEOUS 05 DAY, 20C
PIPE SET QUALIFIER :	9	**MONITORING LOCATION :**	1 = EFFLUENT GROSS VALUE

MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-MAY-2009			< 24.27	3	< 2						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
30-APR-2009			34.09	4	2						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-MAR-2009			39.72	4	2						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
28-FEB-2009			32.62	2	2						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-JAN-2009			32.48	2	2						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-DEC-2008			30.87	3	2						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
30-NOV-2008			41.76	8	3						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-OCT-2008			29.50	2	2						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
30-SEP-2008			40.24	6	3						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-AUG-2008			56.51	8	3						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-JUL-2008			37.92	4	2						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
30-JUN-2008			32.58	2	2						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-MAY-2008			35.30	4	2						E00 = MEASUREMENT ONLY, NO	26 = LBS/DYLBS/DAY POUNDS PER	19 = MG/L MG/L MILLIGRAMS PER

											VIOLATION NO VIOL	DAY	LITER
30-APR-2008			33.11	3	2						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-MAR-2008			30.18	2	2						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
29-FEB-2008			41.97	8	3						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-JAN-2008			37.99	3	2						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-DEC-2007			49.13	5	3						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
30-NOV-2007			49.00	5	3						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-OCT-2007			33.78	2	2						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
30-SEP-2007			37.94	3	2						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER
31-AUG-2007			38.02	4	2						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	26 = LBS/DYLBS/DAY POUNDS PER DAY	19 = MG/L MG/L MILLIGRAMS PER LITER

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
FACILITY NAME (2): USTICE
PIPE NUMBER : SLD
REPORT DESIGNATOR : F
PIPE SET QUALIFIER : 9
MODIFICATION NUM : 0
NPDES : TX0031577
LIMIT TYPE : 5 = FINAL
SEASON NUM : 0
PARAMETER CODE: 49030 = COMPLIANCE W/PART 258 SLUDGE REQUIREMENT
MONITORING LOCATION : + = SLUDGE

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008				1							E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		94 = YES=1 NO=0 YES=1NO=0PRESENCE OF COND: YES=1; NO=0

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
FACILITY NAME (2): USTICE
PIPE NUMBER : SLD
REPORT DESIGNATOR : P
NPDES : TX0031577
LIMIT TYPE : 5 = FINAL
SEASON NUM : 0
PARAMETER CODE: 39516 = POLYCHLORINATED BIPHENYLS (PCBS)

PIPE SET QUALIFIER : 9
MONITORING LOCATION : + = SLUDGE
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008				20							E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		69 = MG/KG MG/KG MILLIGRAMS PER KILOGRAM

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
NPDES : TX0031577
FACILITY NAME (2): USTICE
LIMIT TYPE : 5 = FINAL
PIPE NUMBER : SLD
SEASON NUM : 0
REPORT DESIGNATOR : P
PARAMETER CODE: 46390 = TOXICITY CHARACTERISTIC LEACHING PROCED.
PIPE SET QUALIFIER : 9
MONITORING LOCATION : + = SLUDGE
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008						0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
NPDES : TX0031577
FACILITY NAME (2): USTICE
LIMIT TYPE : 5 = FINAL
PIPE NUMBER : SLD
SEASON NUM : 0
REPORT DESIGNATOR : P
PARAMETER CODE: 49017 = ANN. AMT SLUDGE DISPOSED BY OTHER METHOD
PIPE SET QUALIFIER : 9
MONITORING LOCATION : V = SEE COMMENTS BELOW
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008		0									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	4E = DRYMETTON/YRDMT/YR DRY METRIC TONS PER YEAR	

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
NPDES : TX0031577
FACILITY NAME (2): USTICE
LIMIT TYPE : 5 = FINAL
PIPE NUMBER : SLD
SEASON NUM : 0
REPORT DESIGNATOR : P
PARAMETER CODE: 49018 = ANNUAL AMT OF SLUDGEINCINERATED
PIPE SET QUALIFIER : 9
MONITORING LOCATION : + = SLUDGE
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008		0									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	4E = DRYMETTON/YRDMT/YR DRY METRIC TONS PER YEAR	

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
NPDES : TX0031577
FACILITY NAME (2): USTICE
LIMIT TYPE : 5 = FINAL
PIPE NUMBER : SLD
SEASON NUM : 0
REPORT DESIGNATOR : P
PARAMETER CODE: 49019 = ANNUAL SLUDGE PRODUCTION, TOTAL
PIPE SET QUALIFIER : 9
MONITORING LOCATION : + = SLUDGE
MODIFICATION NUM : 0

MONITORING							RNC	RNC	RNC	RNC	MEASUREMENT		

PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	DETECTION CODE	DETECTION DATE	RESOLUTION CODE	RESOLUTION DATE	VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008		285.5									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	4E = DRYMETTON/YRDMT/YR DRY METRIC TONS PER YEAR	

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2): USTICE **LIMIT TYPE :** 5 = FINAL
PIPE NUMBER : SLD **SEASON NUM :** 0
REPORT DESIGNATOR : P **PARAMETER CODE:** 49020 = ANNUAL AMOUNT OF SLUDGE LAND APPLIED
PIPE SET QUALIFIER : 9 **MONITORING LOCATION :** + = SLUDGE
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008		0									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	4E = DRYMETTON/YRDMT/YR DRY METRIC TONS PER YEAR	

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2): USTICE **LIMIT TYPE :** 5 = FINAL
PIPE NUMBER : SLD **SEASON NUM :** 0
REPORT DESIGNATOR : P **PARAMETER CODE:** 49021 = ANNUAL AMT. SLUDGE DISPOSED SURFACE UNIT
PIPE SET QUALIFIER : 9 **MONITORING LOCATION :** + = SLUDGE
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008		0									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	4E = DRYMETTON/YRDMT/YR DRY METRIC TONS PER YEAR	

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2): USTICE **LIMIT TYPE :** 5 = FINAL
PIPE NUMBER : SLD **SEASON NUM :** 0
REPORT DESIGNATOR : P **PARAMETER CODE:** 49022 = ANNUAL AMT SLUDGE DISPOSED IN LANDFILL
PIPE SET QUALIFIER : 9 **MONITORING LOCATION :** + = SLUDGE
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008		285.5									E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL	4E = DRYMETTON/YRDMT/YR DRY METRIC TONS PER YEAR	

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2): USTICE **LIMIT TYPE :** 5 = FINAL
PIPE NUMBER : SLD **SEASON NUM :** 0
REPORT DESIGNATOR : P **PARAMETER CODE:** 49023 = ANNUAL AMT SLUDGE TRANSPORTED INTERSTATE
PIPE SET QUALIFIER : 9 **MONITORING LOCATION :** + = SLUDGE
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
											E00 =	4E =	

31-JUL-2008		0									MEASUREMENT ONLY, NO VIOLATION NO VIOL	DRYMETTON/YRDMT/YR DRY METRIC TONS PER YEAR	

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
FACILITY NAME (2): USTICE
PIPE NUMBER : SLL
REPORT DESIGNATOR : A
PIPE SET QUALIFIER : 9
MODIFICATION NUM : 0
NPDES : TX0031577
LIMIT TYPE : 5 = FINAL
SEASON NUM : 0
PARAMETER CODE: 01003 = ARSENIC, DRY WEIGHT
MONITORING LOCATION : R = SEE COMMENTS BELOW

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008	C = NO DISCHARGE										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
FACILITY NAME (2): USTICE
PIPE NUMBER : SLL
REPORT DESIGNATOR : A
PIPE SET QUALIFIER : 9
MODIFICATION NUM : 0
NPDES : TX0031577
LIMIT TYPE : 5 = FINAL
SEASON NUM : 0
PARAMETER CODE: 01148 = SELENIUM, DRY WEIGHT
MONITORING LOCATION : R = SEE COMMENTS BELOW

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008	C = NO DISCHARGE										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
FACILITY NAME (2): USTICE
PIPE NUMBER : SLL
REPORT DESIGNATOR : A
PIPE SET QUALIFIER : 9
MODIFICATION NUM : 0
NPDES : TX0031577
LIMIT TYPE : 5 = FINAL
SEASON NUM : 0
PARAMETER CODE: 46394 = COPPER, DRY WEIGHT
MONITORING LOCATION : R = SEE COMMENTS BELOW

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008	C = NO DISCHARGE										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
FACILITY NAME (2): USTICE
PIPE NUMBER : SLL
REPORT DESIGNATOR : A
PIPE SET QUALIFIER : 9
MODIFICATION NUM : 0
NPDES : TX0031577
LIMIT TYPE : 5 = FINAL
SEASON NUM : 0
PARAMETER CODE: 46395 = CADMIUM, DRY WEIGHT
MONITORING LOCATION : R = SEE COMMENTS BELOW

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008	C = NO DISCHARGE										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1):	TEXAS DEPARTMENT OF CRIMINAL J	**NPDES :**	TX0031577
FACILITY NAME (2):	USTICE	**LIMIT TYPE :**	5 = FINAL
PIPE NUMBER :	SLL	**SEASON NUM :**	0
REPORT DESIGNATOR :	A	**PARAMETER CODE:**	49016 = ANNUAL WHOLE SLUDGE APPLICATION RATE
PIPE SET QUALIFIER :	9	**MONITORING LOCATION :**	P = SEE COMMENTS BELOW
MODIFICATION NUM :	0		

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008	C = NO DISCHARGE										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1):	TEXAS DEPARTMENT OF CRIMINAL J	**NPDES :**	TX0031577
FACILITY NAME (2):	USTICE	**LIMIT TYPE :**	5 = FINAL
PIPE NUMBER :	SLL	**SEASON NUM :**	0
REPORT DESIGNATOR :	A	**PARAMETER CODE:**	78465 = MOLYBDENUM, DRY WEIGHT
PIPE SET QUALIFIER :	9	**MONITORING LOCATION :**	R = SEE COMMENTS BELOW
MODIFICATION NUM :	0		

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008	C = NO DISCHARGE										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1):	TEXAS DEPARTMENT OF CRIMINAL J	**NPDES :**	TX0031577
FACILITY NAME (2):	USTICE	**LIMIT TYPE :**	5 = FINAL
PIPE NUMBER :	SLL	**SEASON NUM :**	0
REPORT DESIGNATOR :	A	**PARAMETER CODE:**	78467 = ZINC, DRY WEIGHT
PIPE SET QUALIFIER :	9	**MONITORING LOCATION :**	R = SEE COMMENTS BELOW
MODIFICATION NUM :	0		

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008	C = NO DISCHARGE										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1):	TEXAS DEPARTMENT OF CRIMINAL J	**NPDES :**	TX0031577
FACILITY NAME (2):	USTICE	**LIMIT TYPE :**	5 = FINAL
PIPE NUMBER :	SLL	**SEASON NUM :**	0
REPORT DESIGNATOR :	A	**PARAMETER CODE:**	78468 = LEAD, DRY WEIGHT
PIPE SET QUALIFIER :	9	**MONITORING LOCATION :**	R = SEE COMMENTS BELOW
MODIFICATION NUM :	0		

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008	C = NO DISCHARGE										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1):	TEXAS DEPARTMENT OF CRIMINAL J	**NPDES :**	TX0031577
FACILITY NAME (2):	USTICE	**LIMIT TYPE :**	5 = FINAL
PIPE NUMBER :	SLL	**SEASON NUM :**	0
REPORT DESIGNATOR :	A	**PARAMETER CODE:**	78469 = NICKEL, DRY WEIGHT

PIPE SET QUALIFIER : 9 **MONITORING LOCATION :** R = SEE COMMENTS BELOW
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008	C = NO DISCHARGE										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2): USTICE **LIMIT TYPE :** 5 = FINAL
PIPE NUMBER : SLL **SEASON NUM :** 0
REPORT DESIGNATOR : A **PARAMETER CODE:** 78471 = MERCURY, DRY WEIGHT
PIPE SET QUALIFIER : 9 **MONITORING LOCATION :** R = SEE COMMENTS BELOW
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008	C = NO DISCHARGE										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2): USTICE **LIMIT TYPE :** 5 = FINAL
PIPE NUMBER : SLL **SEASON NUM :** 0
REPORT DESIGNATOR : A **PARAMETER CODE:** 78473 = CHROMIUM, DRY WEIGHT
PIPE SET QUALIFIER : 9 **MONITORING LOCATION :** R = SEE COMMENTS BELOW
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008	C = NO DISCHARGE										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2): USTICE **LIMIT TYPE :** 5 = FINAL
PIPE NUMBER : SLL **SEASON NUM :** 0
REPORT DESIGNATOR : A **PARAMETER CODE:** 84367 = POLLUTANT TABLE FROM 503.13
PIPE SET QUALIFIER : 9 **MONITORING LOCATION :** S = SEE COMMENTS BELOW
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008	C = NO DISCHARGE										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2): USTICE **LIMIT TYPE :** 5 = FINAL
PIPE NUMBER : SLL **SEASON NUM :** 0
REPORT DESIGNATOR : A **PARAMETER CODE:** 84368 = LEVEL OF PATHOGEN REQUIREMENTS ACHIEVED
PIPE SET QUALIFIER : 9 **MONITORING LOCATION :** T = SEE COMMENTS BELOW
MODIFICATION NUM : 0

MONITORING							RNC	RNC	RNC	RNC	MEASUREMENT	QUANTITY	

PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	DETECTION CODE	DETECTION DATE	RESOLUTION CODE	RESOLUTION DATE	VIOLATION CODE	UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008	C = NO DISCHARGE										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2): USTICE **LIMIT TYPE :** 5 = FINAL
PIPE NUMBER : SLL **SEASON NUM :** 0
REPORT DESIGNATOR : A **PARAMETER CODE:** 84369 = DESCRIPTION OF PATHOGEN OPTION USED
PIPE SET QUALIFIER : 9 **MONITORING LOCATION :** + = SLUDGE
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008	C = NO DISCHARGE										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2): USTICE **LIMIT TYPE :** 5 = FINAL
PIPE NUMBER : SLL **SEASON NUM :** 0
REPORT DESIGNATOR : A **PARAMETER CODE:** 84370 = VECTOR ATTRACTION REDUCTION ALTERN USED
PIPE SET QUALIFIER : 9 **MONITORING LOCATION :** + = SLUDGE
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008	C = NO DISCHARGE										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2): USTICE **LIMIT TYPE :** 5 = FINAL
PIPE NUMBER : SLL **SEASON NUM :** 0
REPORT DESIGNATOR : Y **PARAMETER CODE:** 31641 = FECAL COLIFORM
PIPE SET QUALIFIER : 9 **MONITORING LOCATION :** R = SEE COMMENTS BELOW
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008	C = NO DISCHARGE										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2): USTICE **LIMIT TYPE :** 5 = FINAL
PIPE NUMBER : SLL **SEASON NUM :** 0
REPORT DESIGNATOR : Y **PARAMETER CODE:** 71204 = SALMONELLA
PIPE SET QUALIFIER : 9 **MONITORING LOCATION :** R = SEE COMMENTS BELOW
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
											E00 =		

31-JUL-2008	C = NO DISCHARGE										MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2): USTICE **LIMIT TYPE :** 5 = FINAL
PIPE NUMBER : SLS **SEASON NUM :** 0
REPORT DESIGNATOR : A **PARAMETER CODE:** 00400 = PH
PIPE SET QUALIFIER : 9 **MONITORING LOCATION :** + = SLUDGE
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008	C = NO DISCHARGE										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2): USTICE **LIMIT TYPE :** 5 = FINAL
PIPE NUMBER : SLS **SEASON NUM :** 0
REPORT DESIGNATOR : A **PARAMETER CODE:** 01003 = ARSENIC, DRY WEIGHT
PIPE SET QUALIFIER : 9 **MONITORING LOCATION :** + = SLUDGE
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008	C = NO DISCHARGE										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2): USTICE **LIMIT TYPE :** 5 = FINAL
PIPE NUMBER : SLS **SEASON NUM :** 0
REPORT DESIGNATOR : A **PARAMETER CODE:** 01067 = NICKEL, TOTAL (AS NI)
PIPE SET QUALIFIER : 9 **MONITORING LOCATION :** + = SLUDGE
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008	C = NO DISCHARGE										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2): USTICE **LIMIT TYPE :** 5 = FINAL
PIPE NUMBER : SLS **SEASON NUM :** 0
REPORT DESIGNATOR : A **PARAMETER CODE:** 49028 = UNIT W/LINER/LEACHATE COLLECTION SYSTEM
PIPE SET QUALIFIER : 9 **MONITORING LOCATION :** + = SLUDGE
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008	C = NO DISCHARGE										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
FACILITY NAME (2): USTICE
PIPE NUMBER : SLS
REPORT DESIGNATOR : A
PIPE SET QUALIFIER : 9
MODIFICATION NUM : 0
NPDES : TX0031577
LIMIT TYPE : 5 = FINAL
SEASON NUM : 0
PARAMETER CODE: 51004 = BOUNDARY AREAS
MONITORING LOCATION : + = SLUDGE

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008	C = NO DISCHARGE										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
FACILITY NAME (2): USTICE
PIPE NUMBER : SLS
REPORT DESIGNATOR : A
PIPE SET QUALIFIER : 9
MODIFICATION NUM : 0
NPDES : TX0031577
LIMIT TYPE : 5 = FINAL
SEASON NUM : 0
PARAMETER CODE: 78473 = CHROMIUM, DRY WEIGHT
MONITORING LOCATION : + = SLUDGE

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008	C = NO DISCHARGE										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
FACILITY NAME (2): USTICE
PIPE NUMBER : SLS
REPORT DESIGNATOR : A
PIPE SET QUALIFIER : 9
MODIFICATION NUM : 0
NPDES : TX0031577
LIMIT TYPE : 5 = FINAL
SEASON NUM : 0
PARAMETER CODE: 84368 = LEVEL OF PATHOGEN REQUIREMENTS ACHIEVED
MONITORING LOCATION : T = SEE COMMENTS BELOW

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008	C = NO DISCHARGE										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
FACILITY NAME (2): USTICE
PIPE NUMBER : SLS
REPORT DESIGNATOR : A
PIPE SET QUALIFIER : 9
MODIFICATION NUM : 0
NPDES : TX0031577
LIMIT TYPE : 5 = FINAL
SEASON NUM : 0
PARAMETER CODE: 84369 = DESCRIPTION OF PATHOGEN OPTION USED
MONITORING LOCATION : + = SLUDGE

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008	C = NO DISCHARGE										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
FACILITY NAME (2): USTICE
PIPE NUMBER : SLS
REPORT DESIGNATOR : A
NPDES : TX0031577
LIMIT TYPE : 5 = FINAL
SEASON NUM : 0
PARAMETER CODE: 84370 = VECTOR ATTRACTION REDUCTION ALTERN USED

PIPE SET QUALIFIER : 9 **MONITORING LOCATION :** + = SLUDGE
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-JUL-2008	C = NO DISCHARGE										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2): USTICE **LIMIT TYPE :** 5 = FINAL
PIPE NUMBER : TX1 **SEASON NUM :** 0
REPORT DESIGNATOR : Q **PARAMETER CODE:** 22415 = WHOLE EFFLUENT TOXICITY - RETEST #1
PIPE SET QUALIFIER : 9 **MONITORING LOCATION :** 1 = EFFLUENT GROSS VALUE
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-MAR-2009	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
31-DEC-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
30-SEP-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
30-JUN-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
31-MAR-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
31-DEC-2007	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2): USTICE **LIMIT TYPE :** 5 = FINAL
PIPE NUMBER : TX1 **SEASON NUM :** 0
REPORT DESIGNATOR : Q **PARAMETER CODE:** 22416 = WHOLE EFFLUENT TOXICITY - RETEST #2
PIPE SET QUALIFIER : 9 **MONITORING LOCATION :** 1 = EFFLUENT GROSS VALUE
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-MAR-2009	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

31-DEC-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
30-SEP-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
30-JUN-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
31-MAR-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
31-DEC-2007	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
NPDES : TX0031577
FACILITY NAME (2): USTICE
LIMIT TYPE : 5 = FINAL
PIPE NUMBER : TX1
SEASON NUM : 0
REPORT DESIGNATOR : Q
PARAMETER CODE: TLP3B = LF P/F LETH STATRE 7DAY CHR CERIODAPHNIA
PIPE SET QUALIFIER : 9
MONITORING LOCATION : 1 = EFFLUENT GROSS VALUE
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-MAR-2009					0	0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1
31-DEC-2008					0	0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1
30-SEP-2008					0	0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1
30-JUN-2008					0	0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1
31-MAR-2008					0	0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1
31-DEC-2007					0	0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
NPDES : TX0031577
FACILITY NAME (2): USTICE
LIMIT TYPE : 5 = FINAL

PIPE NUMBER : TX1
REPORT DESIGNATOR : Q
PIPE SET QUALIFIER : 9
MODIFICATION NUM : 0
SEASON NUM : 0
PARAMETER CODE: TLP6C = LF P/F LETH STATRE 7DAY CHR PIMEPHALES
MONITORING LOCATION : 1 = EFFLUENT GROSS VALUE

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-MAR-2009					0	0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1
31-DEC-2008					0	0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1
30-SEP-2008					0	0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1
30-JUN-2008					0	0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1
31-MAR-2008					0	0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1
31-DEC-2007					0	0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
FACILITY NAME (2): USTICE
PIPE NUMBER : TX1
REPORT DESIGNATOR : Q
PIPE SET QUALIFIER : 9
MODIFICATION NUM : 0
NPDES : TX0031577
LIMIT TYPE : 5 = FINAL
SEASON NUM : 0
PARAMETER CODE: TOP3B = NOEL LETHAL STATRE 7DAY CHR CERIODAPHNIA
MONITORING LOCATION : 1 = EFFLUENT GROSS VALUE

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-MAR-2009					98	98					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		23 = PER- CENT PERCENT PERCENT
31-DEC-2008					98	98					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		23 = PER- CENT PERCENT PERCENT
30-SEP-2008					98	98					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		23 = PER- CENT PERCENT PERCENT
30-JUN-2008					98	98					E00 = MEASUREMENT ONLY, NO VIOLATION NO		23 = PER- CENT PERCENT PERCENT

											VIOL		
31-MAR-2008					98	98					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		23 = PER- CENT PERCENT PERCENT
31-DEC-2007					98	98					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		23 = PER- CENT PERCENT PERCENT

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
FACILITY NAME (2): USTICE
PIPE NUMBER : TX1
REPORT DESIGNATOR : Q
PIPE SET QUALIFIER : 9
MODIFICATION NUM : 0
NPDES : TX0031577
LIMIT TYPE : 5 = FINAL
SEASON NUM : 0
PARAMETER CODE: TOP6C = NOEL LETHAL STATRE 7DAY CHR PIMEPHALES
MONITORING LOCATION : 1 = EFFLUENT GROSS VALUE

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-MAR-2009					98	98					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		23 = PER- CENT PERCENT PERCENT
31-DEC-2008					98	98					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		23 = PER- CENT PERCENT PERCENT
30-SEP-2008					98	98					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		23 = PER- CENT PERCENT PERCENT
30-JUN-2008					98	98					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		23 = PER- CENT PERCENT PERCENT
31-MAR-2008					98	98					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		23 = PER- CENT PERCENT PERCENT
31-DEC-2007					98	98					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		23 = PER- CENT PERCENT PERCENT

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
FACILITY NAME (2): USTICE
PIPE NUMBER : TX1
REPORT DESIGNATOR : Q
PIPE SET QUALIFIER : 9
MODIFICATION NUM : 0
NPDES : TX0031577
LIMIT TYPE : 5 = FINAL
SEASON NUM : 0
PARAMETER CODE: TPP3B = NOEL SUB-LTH STATRE 7DAY CHR CERIODAPHNIA
MONITORING LOCATION : 1 = EFFLUENT GROSS VALUE

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-MAR-2009					98	98					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		23 = PER- CENT PERCENT PERCENT

31-DEC-2008					98	98					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		23 = PER- CENT PERCENT PERCENT
30-SEP-2008					98	98					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		23 = PER- CENT PERCENT PERCENT
30-JUN-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
31-MAR-2008					98	98					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		23 = PER- CENT PERCENT PERCENT
31-DEC-2007	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2): USTICE **LIMIT TYPE :** 5 = FINAL
PIPE NUMBER : TX1 **SEASON NUM :** 0
REPORT DESIGNATOR : Q **PARAMETER CODE:** TPP6C = NOEL SUB-LTH STATRE 7DAY CHR PIMEPHALES
PIPE SET QUALIFIER : 9 **MONITORING LOCATION :** 1 = EFFLUENT GROSS VALUE
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-MAR-2009					98	98					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		23 = PER- CENT PERCENT PERCENT
31-DEC-2008					98	98					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		23 = PER- CENT PERCENT PERCENT
30-SEP-2008					98	98					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		23 = PER- CENT PERCENT PERCENT
30-JUN-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
31-MAR-2008					98	98					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		23 = PER- CENT PERCENT PERCENT
31-DEC-2007	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2): USTICE **LIMIT TYPE :** 5 = FINAL

PIPE NUMBER : TX1
REPORT DESIGNATOR : Q
PIPE SET QUALIFIER : 9
MODIFICATION NUM : 0
SEASON NUM : 0
PARAMETER CODE: TWP3B = P/F SUB-LETHAL 7 DAY CERIODAPHNIA DUBIA
MONITORING LOCATION : 1 = EFFLUENT GROSS VALUE

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-MAR-2009					0	0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1
31-DEC-2008					0	0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1
30-SEP-2008					0	0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1
30-JUN-2008					0	0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1
31-MAR-2008					0	0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1
31-DEC-2007					0	0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
FACILITY NAME (2): USTICE
PIPE NUMBER : TX1
REPORT DESIGNATOR : Q
PIPE SET QUALIFIER : 9
MODIFICATION NUM : 0
NPDES : TX0031577
LIMIT TYPE : 5 = FINAL
SEASON NUM : 0
PARAMETER CODE: TWP6C = P/F SUB-LETHAL 7 DAYPINEPHALES PROMELAS
MONITORING LOCATION : 1 = EFFLUENT GROSS VALUE

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-MAR-2009					0	0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1
31-DEC-2008					0	0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1
30-SEP-2008					0	0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1
30-JUN-2008					0	0					E00 = MEASUREMENT ONLY, NO VIOLATION NO		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1

											VIOL		
31-MAR-2008					0	0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1
31-DEC-2007					0	0					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
NPDES : TX0031577
FACILITY NAME (2): USTICE
LIMIT TYPE : 5 = FINAL
PIPE NUMBER : TX1
SEASON NUM : 0
REPORT DESIGNATOR : Q
PARAMETER CODE: TXP3B = 7-DAY CHR. CERIODPH (LETHAL EFFECTS)
PIPE SET QUALIFIER : 9
MONITORING LOCATION : 1 = EFFLUENT GROSS VALUE
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-MAR-2009	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
31-DEC-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
30-SEP-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
30-JUN-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
31-MAR-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
31-DEC-2007					100	100					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		23 = PER- CENT PERCENT PERCENT

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
NPDES : TX0031577
FACILITY NAME (2): USTICE
LIMIT TYPE : 5 = FINAL
PIPE NUMBER : TX1
SEASON NUM : 0
REPORT DESIGNATOR : Q
PARAMETER CODE: TXP6C = 7-DAY CHR. PIMEPHALE(LETHAL EFFECTS)
PIPE SET QUALIFIER : 9
MONITORING LOCATION : 1 = EFFLUENT GROSS VALUE
MODIFICATION NUM : 0

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-MAR-2009	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

31-DEC-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
30-SEP-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
30-JUN-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
31-MAR-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
31-DEC-2007					100	100					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		23 = PER- CENT PERCENT PERCENT

FACILITY NAME (1):	TEXAS DEPARTMENT OF CRIMINAL J	**NPDES :**	TX0031577
FACILITY NAME (2):	USTICE	**LIMIT TYPE :**	5 = FINAL
PIPE NUMBER :	TX1	**SEASON NUM :**	0
REPORT DESIGNATOR :	Q	**PARAMETER CODE:**	TYP3B = 7-DAY CHR. CERIODPHN(SUB-LETHAL EFFECT)
PIPE SET QUALIFIER :	9	**MONITORING LOCATION :**	1 = EFFLUENT GROSS VALUE
MODIFICATION NUM :	0		

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-MAR-2009	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
31-DEC-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
30-SEP-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
30-JUN-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
31-MAR-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
31-DEC-2007					100	100					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		23 = PER- CENT PERCENT PERCENT

FACILITY NAME (1):	TEXAS DEPARTMENT OF CRIMINAL J	**NPDES :**	TX0031577
FACILITY NAME (2):	USTICE	**LIMIT TYPE :**	5 = FINAL

PIPE NUMBER : TX1
REPORT DESIGNATOR : Q
PIPE SET QUALIFIER : 9
MODIFICATION NUM : 0
SEASON NUM : 0
PARAMETER CODE: TYP6C = 7-DAY CHR. PIMEPHALE(SUB-LETHAL EFFECT)
MONITORING LOCATION : 1 = EFFLUENT GROSS VALUE

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
31-MAR-2009	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
31-DEC-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
30-SEP-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
30-JUN-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
31-MAR-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
31-DEC-2007					100	100					E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		23 = PER- CENT PERCENT PERCENT

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
FACILITY NAME (2): USTICE
PIPE NUMBER : TXA
REPORT DESIGNATOR : S
PIPE SET QUALIFIER : 9
MODIFICATION NUM : 0
NPDES : TX0031577
LIMIT TYPE : 5 = FINAL
SEASON NUM : 0
PARAMETER CODE: 22415 = WHOLE EFFLUENT TOXICITY - RETEST #1
MONITORING LOCATION : 1 = EFFLUENT GROSS VALUE

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
30-JUN-2009	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
31-DEC-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP						N = RPT-NONRECEIPT OF DMR/CS RPT	19-FEB-2009	2 = RE-BACK INTO COMPLIANCE	30-APR-2009	E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
30-JUN-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
FACILITY NAME (2): USTICE
PIPE NUMBER : TXA
NPDES : TX0031577
LIMIT TYPE : 5 = FINAL
SEASON NUM : 0

REPORT DESIGNATOR : S
PIPE SET QUALIFIER : 9
MODIFICATION NUM : 0
PARAMETER CODE: 22416 = WHOLE EFFLUENT TOXICITY - RETEST #2
MONITORING LOCATION : 1 = EFFLUENT GROSS VALUE

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
30-JUN-2009	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
31-DEC-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP						N = RPT-NONRECEIPT OF DMR/CS RPT	19-FEB-2009	2 = RE-BACK INTO COMPLIANCE	30-APR-2009	E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		
30-JUN-2008	9 = MONITORING IS CONDITIONAL/NOT REQ THIS MP										E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
FACILITY NAME (2): USTICE
PIPE NUMBER : TXA
REPORT DESIGNATOR : S
PIPE SET QUALIFIER : 9
MODIFICATION NUM : 0
NPDES : TX0031577
LIMIT TYPE : 5 = FINAL
SEASON NUM : 0
PARAMETER CODE: TIE3D = LC50/PF STAT 24HR ACU D. PULEX
MONITORING LOCATION : 1 = EFFLUENT GROSS VALUE

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
30-JUN-2009					0						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1
31-DEC-2008					0		N = RPT-NONRECEIPT OF DMR/CS RPT	19-FEB-2009	2 = RE-BACK INTO COMPLIANCE	30-APR-2009	E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1
30-JUN-2008					0						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1

FACILITY NAME (1): TEXAS DEPARTMENT OF CRIMINAL J
FACILITY NAME (2): USTICE
PIPE NUMBER : TXA
REPORT DESIGNATOR : S
PIPE SET QUALIFIER : 9
MODIFICATION NUM : 0
NPDES : TX0031577
LIMIT TYPE : 5 = FINAL
SEASON NUM : 0
PARAMETER CODE: TIE6C = LC50/PF STAT 24HR ACU PIMPHALES
MONITORING LOCATION : 1 = EFFLUENT GROSS VALUE

MONITORING PERIOD END DATE	DISCHARGE IND	QTY MAXIMUM	QTY AVERAGE	CONC MAXIMUM	CONC AVERAGE	CONC MINIMUM	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOLUTION DATE	MEASUREMENT VIOLATION CODE	QUANTITY UNIT CODE	CONCENTRATION UNIT CODE
30-JUN-2009					0						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1
31-DEC-2008					0		N = RPT-NONRECEIPT OF DMR/CS	19-FEB-2009	2 = RE-BACK INTO COMPLIANCE	30-APR-2009	E00 = MEASUREMENT ONLY, NO VIOLATION NO		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1

							RPT				VIOL		
30-JUN-2008					0						E00 = MEASUREMENT ONLY, NO VIOLATION NO VIOL		9A = PASS=0FAIL=1PASS/FAILPASS=0, FAIL=1

Compliance Schedules and Violations

FACILITY NAME (1) : TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2): USTICE

Compliance Schedule Events

SCHEDULE NUMBER	DATA SOURCE	EVENT CODE	EVENT DESCRIPTION	ACTUAL DATE	SCHEDULED DATE	RECEIVED DATE
01	0786 = 99ZZ	00199	1ST REPORT OF PROGRESS	04-APR-1975	01-JAN-1975	04-APR-1975
01	0786 = 99ZZ	02599	FINANCING COMPLTE CONTR AWRD	06-JUL-1976	01-SEP-1975	06-JUL-1976
01	0786 = 99ZZ	05599	OPERATIONAL LEVEL ATTAINED	28-APR-1977	01-JUL-1977	28-APR-1977

Compliance Schedule Violations

SCHEDULE NUMBER	DATA SOURCE	EVENT CODE	VIOLATION	VIOLATION DATE	RNC DETECTION CODE	RNC DETECTION DATE	RNC RESOLUTION CODE	RNC RESOULTION DATE
01	0786 = 99ZZ	02599	C20 = ACHIEVED LATE VIOLATION	01-SEP-1975	S = SCH-COMPLIANCE SCHEDULE VIOL		2 = RE-BACK INTO COMPLIANCE	06-JUL-1976
01	0786 = 99ZZ	00199	C20 = ACHIEVED LATE VIOLATION	01-JAN-1975	N = RPT-NONRECEIPT OF DMR/CS RPT		2 = RE-BACK INTO COMPLIANCE	04-APR-1975

Evidentiary Hearings

FACILITY NAME (1) : TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2) : USTICE

No PCS Evidentiary Hearing Information Found.

Pretreatment Inspections/Audits

FACILITY NAME (1) : TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2) : USTICE

No PCS Pretreatment Inspections Found.

Pretreatment Performance Summary

FACILITY NAME (1) : TEXAS DEPARTMENT OF CRIMINAL J **NPDES :** TX0031577
FACILITY NAME (2) : USTICE

No PCS Pretreatment Performance Summary Information Found.

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Last updated on Thursday, February 4th, 2010.
http://oaspub.epa.gov/enviro/pcs_det_reports.pcs_tst?npdesid=TX0031577&npvalue=1&npvalue=2&npvalue=3&npvalue=4&npvalue=5&npvalue=6&rvalue=13&npvalue=7&npvalue=8&npvalue=10&npvalue=11&npvalue=12
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U.S. ENVIRONMENTAL PROTECTION AGENCY

Facility Registry System (FRS)

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Facility Detail Report

FRS

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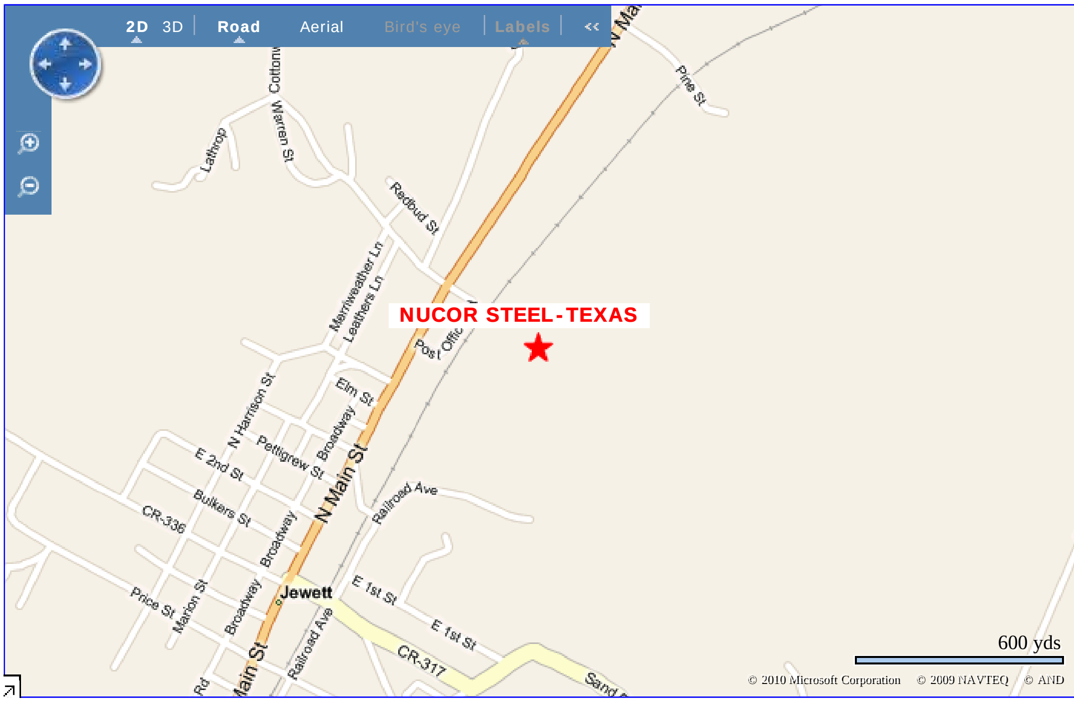

Legend

★ Selected Facility
EPA Facility of Interest
State/Tribe Facility of Interest

The facility locations displayed come from the FRS Spatial Coordinates tables. They are the best representative locations for the displayed facilities based on the accuracy of the collection method and quality assurance checks performed against each location. The North American Datum of 1983 is used to display all coordinates.

Environmental Interests

Information System	Information System ID	Environmental Interest Type	Data Source	Last Updated Date	Supplemental Environmental Interests:
AIR FACILITY SYSTEM	4828900001	AIR MAJOR ()	AIRS/AFS	09/02/2009	
INTEGRATED COMPLIANCE INFORMATION SYSTEM	35421	FORMAL ENFORCEMENT ACTION	ICIS	09/25/2001	**ICIS**-06-1986-0106 FORMAL ENFORCEMENT ACTION **ICIS**-06-1992-0018 FORMAL ENFORCEMENT ACTION **ICIS**-06-1998-0872 FORMAL ENFORCEMENT ACTION
INTEGRATED COMPLIANCE INFORMATION SYSTEM	35421	ENFORCEMENT/COMPLIANCE ACTIVITY	ICIS	10/14/2004	**ICIS**-06-1986-0106 FORMAL ENFORCEMENT ACTION **ICIS**-06-1992-0018 FORMAL ENFORCEMENT ACTION **ICIS**-06-1998-0872 FORMAL ENFORCEMENT ACTION
RESOURCE CONSERVATION AND RECOVERY ACT INFORMATION SYSTEM	TXD071378582	CORRECTIVE ACTION (ACTIVE)	RCRAINFO	04/27/2009	**ICIS**-ENFORCEMENT/COMPLIANCE ACTIVITY
RESOURCE CONSERVATION AND RECOVERY ACT INFORMATION SYSTEM	TXD071378582	HAZARDOUS WASTE BIENNIAL REPORTER (ACTIVE)	RCRAINFO	12/31/2007	**ICIS**-ENFORCEMENT/COMPLIANCE ACTIVITY
RESOURCE CONSERVATION AND RECOVERY ACT INFORMATION SYSTEM	TXD071378582	LQG (ACTIVE)	RCRAINFO	04/27/2009	**ICIS**-ENFORCEMENT/COMPLIANCE ACTIVITY
RESOURCE CONSERVATION AND RECOVERY ACT INFORMATION SYSTEM	TXR000050823	UNSPECIFIED UNIVERSE (INACTIVE)	RCRAINFO	08/13/2003	
TOXIC RELEASE INVENTORY SYSTEM	75846NCRSTHWY79	TRI REPORTER	TRI REPORTING FORM	06/29/2009	
					PERMIT-1289

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY - AGENCY CENTRAL REGISTRY	RN100211093	STATE MASTER	TX-TCEQ ACR		AIR OPERATING PERMITS **REGISTRATION**-1450014 PUBLIC WATER SYSTEM/SUPPLY **REGISTRATION**-20949 PETROLEUM STORAGE TANK REGISTRATION **PERMIT**-2430 AIR NEW SOURCE PERMITS **SOLID WASTE REGISTRA**-33095 IHW CORRECTIVE ACTION **SOLID WASTE REGISTRA**-33095 INDUSTRIAL AND HAZARDOUS WASTE GENERATION **AFS NUM**-4828900001 AIR NEW SOURCE PERMITS **PERMIT**-53581 AIR NEW SOURCE PERMITS **PERMIT**-6811 AIR NEW SOURCE PERMITS **PERMIT**-6811A AIR NEW SOURCE PERMITS **PERMIT**-6811B AIR NEW SOURCE PERMITS **REGISTRATION**-82710 AIR NEW SOURCE PERMITS **ACCOUNT NUMBER**-LG0006S AIR NEW SOURCE PERMITS **ACCOUNT NUMBER**-LG0006S AIR OPERATING PERMITS **PERMIT**-P1029 AIR NEW SOURCE PERMITS **EPA ID**-PSDTX1029 AIR NEW SOURCE PERMITS **EPA ID**-PSDTX128M1 AIR NEW SOURCE PERMITS **EPA ID**-TXD071378582 INDUSTRIAL AND HAZARDOUS WASTE GENERATION **ID NUMBER**-TXR05A252 WATER QUALITY NON PERMITTED **PERMIT**-TXR05P203 STORMWATER **PERMIT**-WQ0001897000 WASTEWATER **PERMIT**-53581 AIR PROGRAM **EPA ID**-PSDTX128M1 AIR PROGRAM **EPA ID**-TXD071378582 HAZARDOUS WASTE PROGRAM **PERMIT**-WQ0001897000 NPDES PERMIT **PERMIT**-6811 AIR PROGRAM **SOLID WASTE REGISTRA**-33095 HAZARDOUS WASTE PROGRAM **PERMIT**-1289 AIR PROGRAM **EPA ID**-PSDTX1029 AIR PROGRAM **REGISTRATION**-82710 AIR PROGRAM **AFS NUM**-4828900001 AIR PROGRAM **ACCOUNT NUMBER**-LG0006S AIR PROGRAM **SOLID WASTE REGISTRA**-33095 CORRECTIVE ACTION **REGISTRATION**-20949 UNDERGROUND STORAGE TANK PROGRAM **PERMIT**-P1029 AIR PROGRAM **EPA ID**-PSDTX1029M1 AIR PROGRAM **PERMIT**-6811B AIR PROGRAM **ID NUMBER**-TXR05A252 WASTEWATER PROGRAM **PERMIT**-6811A AIR PROGRAM **ACCOUNT NUMBER**-LG0006S AIR PROGRAM **REGISTRATION**-1450014 COMMUNITY WATER SYSTEM **PERMIT**-2430

					AIR PROGRAM **PERMIT**-TXR05P203 NPDES STORMWATER PERMIT **PERMIT**-TXR151105 NPDES STORMWATER PERMIT **PERMIT**-TXR15NP06 NPDES STORMWATER PERMIT **REGISTRATION**-89887 AIR PROGRAM **RCRIS**-PAD987350303 HAZARDOUS WASTE PROGRAM **ACCOUNT NUMBER**-LG0006S AIR EMISSION INVENTORY

Additional EPA Reports: MyEnvironment Enforcement and Compliance Cleanups in My Community Site Demographics Watershed Report

Standard Industrial Classification Codes (SIC)

Data Source	SIC Code	Description	Primary
TRIS	3312	STEEL WORKS, BLAST FURNACES (INCLUDING COKE OVENS), AND ROLLING MILLS	
AIRS/AFS	3312	STEEL WORKS, BLAST FURNACES (INCLUDING COKE OVENS), AND ROLLING MILLS	
ICIS	3312	STEEL WORKS, BLAST FURNACES (INCLUDING COKE OVENS), AND ROLLING MILLS	
TX-TCEQ ACR	3312	STEEL WORKS, BLAST FURNACES (INCLUDING COKE OVENS), AND ROLLING MILLS	
TRIS	3310		

Facility Codes and Flags

EPA Region:	06
Duns Number:	071378582
Congressional District Number:	05
Legislative District Number:	09
HUC Code/Watershed:	12030202 / LOWER TRINITY-KICKAPOO
US Mexico Border Indicator:	NO
Federal Facility:	NO
Tribal Land:	NO

Alternative Names

Alternative Name	Source of Data
NUCOR CORP	NOTIFICATION (RCRA)
JEWETT PLANT STEEL MILL	AIRS/AFS
WILLIAM KONTOR	AIRS/AFS
JEWETT PLANT	RCRAINFO
NUCOR STEEL - JEWETT	TX-TCEQ ACR

Organizations

Affiliation Type	Name	DUNS Number	Information System	Mailing Address
OWNER	NUCOR CORPORATION		RCRAINFO	View
OPERATOR	NUCOR CORPORATION		RCRAINFO	View
OWNER	UNKNOWN		RCRAINFO	View
OWNER/OPERATOR		071378582	AIRS/AFS	
OWNER	NUCOR CORPORATION		RCRAINFO	View
OPERATOR	NUCOR CORPORATION		RCRAINFO	View
OWNER OPERATOR	NUCOR CORPORATION	071378582	TX-TCEQ ACR	View
OWNER/OPERATOR		071378582	TRIS	
PARENT ORGANIZATION	NUCOR CORP	003446796	TRIS	

National Industry Classification System Codes (NAICS)

Data Source	NAICS Code	Description	Primary
TX-TCEQ ACR	331111	IRON AND STEEL MILLS.	
RCRAINFO	331111	IRON AND STEEL MILLS.	
TRIS	331111	IRON AND STEEL MILLS.	
TRIS	331221	ROLLED STEEL SHAPE MANUFACTURING.	

Facility Mailing Addresses

Affiliation Type	Delivery Point	City Name	State	Postal Code	Information System
FACILITY MAILING ADDRESS	PO BOX 126	JEWETT	TX	75846	AIRS/AFS
OWNER	8812 HWY 79 WEST	JEWETT	TX	75846	RCRAINFO
MAILING ADDRESS	PO BOX 1642	HOUSTON	PA	77251-1642	TX-TCEQ ACR
MAILING ADDRESS	8812 US HIGHWAY 79 W	JEWETT	TX	75846	TX-TCEQ ACR
FACILITY MAILING ADDRESS	PO BOX 126	JEWETT	TX	75846	RCRAINFO
OPERATOR	PO BOX 126	JEWETT	TX	75846	RCRAINFO
OWNER	PO BOX 126	JEWETT	TX	75846	RCRAINFO
REGULATORY CONTACT	PO BOX 126	JEWETT	TX	75846	RCRAINFO
FACILITY MAILING ADDRESS	8812 HWY 79 WEST	JEWETT	TX	75846	RCRAINFO
OTHER	5400 WESTHEIMER CT	HOUSTON	PA	77056-5310	TX-TCEQ ACR
MAILING ADDRESS	8812 US HIGHWAY 79 S	JEWETT	TX	75846	TX-TCEQ ACR
OWNER OPERATOR	PO BOX 126	JEWETT	TX	758460126	TX-TCEQ ACR
FACILITY MAILING ADDRESS	PO BOX 126	JEWETT	TX	758460126	TRIS

Contacts

Affiliation Type	Full Name	Office Phone	Information System	Mailing Address
REGULATORY CONTACT	MICHAEL SCHULZ	9036264461	RCRAINFO	View
COMPLIANCE CONTACT	NOEL LUERA	9036264461	AIRS/AFS	
PUBLIC CONTACT	KIM PRITCHARD	9036264461	TRIS	
OTHER	DAVID A FELCMAN	7139898331	TX-TCEQ ACR	View

Query executed on: FEB-04-2010

Additional information for CERCLIS or TRI sites:

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http://oaspub.epa.gov/enviro/fii_query_dtl.disp_program_facility?pgm_sys_id_in=TXD071378582&pgm_sys_acrnm_in=RCRAINFO
Print As-Is

Query Results

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PCS

NPDES: Equal To: OK0044172

Results are based on data extracted on JAN-20-2010

Note: Click on the underlined CORPORATE LINK value for links to that company's environmental web pages.
Click on the underlined MAPPING INFO value to obtain mapping information for the facility.
Click on the underlined NPDES value to view detailed reports on the facility.

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Facility Information

FACILITY NAME:	TRINTITY MATERIALS, INC.	NPDES:	OK0044172
STREET 1:	7916 RIVER ROAD		
CITY:	COLBERT	PERMIT ISSUED DATE:	APR-14-2006
STATE:	OK	PERMIT EXPIRED DATE:	APR-30-2011
ZIP CODE:	74733		
COUNTY NAME:	BRYAN	SIC CODE:	1442 CONSTRUCTION SAND AND GRAVEL
REGION:	6	MAPPING INFO:	MAP
MAILING NAME:	TRINITY MATERIALS, INC.		

List of Permitted Discharges

PIPE NUMBER	REPORT DESIGNATOR	PIPE SET QUALIFIER	PIPE DESCRIPTION	PARAMETER CODE	PARAMETER DESCRIPTION
001	A	9	PROCESS WASTEWATER	00400	PH
001	A	9	PROCESS WASTEWATER	00530	SOLIDS, TOTAL SUSPENDED
001	A	9	PROCESS WASTEWATER	50050	FLOW, IN CONDUIT OR THRU TREATMENT PLANT

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U.S. ENVIRONMENTAL PROTECTION AGENCY

Water Discharge Permits (PCS)

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Query Results

PCS

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NPDES: Equal To: TX0053368

Results are based on data extracted on JAN-20-2010

Note: Click on the underlined CORPORATE LINK value for links to that company's environmental web pages.
Click on the underlined MAPPING INFO value to obtain mapping information for the facility.
Click on the underlined NPDES value to view detailed reports on the facility.

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Facility Information

FACILITY NAME:	CITY OF BELLS	NPDES:	TX0053368
STREET 1:	U.S. HWY 69 AND FM HWY 1897, N		
CITY:	BELLS	PERMIT ISSUED DATE:	MAY-16-2007
STATE:	TX	PERMIT EXPIRED DATE:	DEC-01-2011
ZIP CODE:	75414		
COUNTY NAME:	GRAYSON	SIC CODE:	4952 SEWERAGE SYSTEMS
REGION:	6	MAPPING INFO:	MAP
MAILING NAME:	CITY OF BELLS		

List of Permitted Discharges

PIPE NUMBER	REPORT DESIGNATOR	PIPE SET QUALIFIER	PIPE DESCRIPTION	PARAMETER CODE	PARAMETER DESCRIPTION
001	A	9	DOMESTIC FACILITY - 001	00300	OXYGEN, DISSOLVED (DO)
001	A	9	DOMESTIC FACILITY - 001	00310	BOD, 5-DAY (20 DEG. C)
SLS	A	9	SURFACE DISPOSAL-SLSA	00400	PH
001	A	9	DOMESTIC FACILITY - 001	00400	PH
001	A	9	DOMESTIC FACILITY - 001	00530	SOLIDS, TOTAL SUSPENDED
SLS	A	9	SURFACE DISPOSAL-SLSA	01003	ARSENIC IN BOTTOM DEPOSITS (DRY WGT)
SLL	A	9	LAND APPLICATION - SLLA	01003	ARSENIC IN BOTTOM DEPOSITS (DRY WGT)
SLS	A	9	SURFACE DISPOSAL-SLSA	01067	NICKEL, TOTAL (AS NI)
SLL	A	9	LAND APPLICATION - SLLA	01148	SELENIUM IN BOTTOM DEPOSITS (DRY WGT)
SLL	A	9	LAND APPLICATION - SLLA	46394	COPPER, TOTAL SLUDGE
SLL	A	9	LAND APPLICATION - SLLA	46395	CADIUM, TOTAL SLUDGE

SLL	A	9	LAND APPLICATION - SLLA	49016	ANNUAL WHOLE SLUDGE APPLICATION RATE
SLS	A	9	SURFACE DISPOSAL-SLSA	49028	UNIT W/LINER/LEACHATE COLLECTION SYSTEM
001	A	9	DOMESTIC FACILITY - 001	50050	FLOW, IN CONDUIT OR THRU TREATMENT PLANT
001	A	9	DOMESTIC FACILITY - 001	50060	CHLORINE, TOTAL RESIDUAL
SLL	A	9	LAND APPLICATION - SLLA	78465	MOLYBDENUM, SLUDGE, TOT, DRY WT. (AS MO)
SLL	A	9	LAND APPLICATION - SLLA	78467	ZINC, SLUDGE, TOTAL, DRY WEIGHT, (AS ZN)
SLL	A	9	LAND APPLICATION - SLLA	78468	LEAD, SLUDGE, TOTAL, DRY WEIGHT (AS PB)
SLL	A	9	LAND APPLICATION - SLLA	78469	NICKEL, SLUDGE, TOT, DRY WEIGHT (AS NI)
SLL	A	9	LAND APPLICATION - SLLA	78471	MERCURY, SLUDGE, TOT DRY WEIGHT (AS HG)
SLL	A	9	LAND APPLICATION - SLLA	78473	CHROMIUM, SLUDGE, TOT, DRY WT. (AS CR)
SLS	A	9	SURFACE DISPOSAL-SLSA	78473	CHROMIUM, SLUDGE, TOT, DRY WT. (AS CR)
SLL	A	9	LAND APPLICATION - SLLA	84367	POLLUTANT TABLE FROM 503.13
SLL	A	9	LAND APPLICATION - SLLA	84368	LEVEL OF PATHOGEN REQUIREMENTS ACHIEVED
SLS	A	9	SURFACE DISPOSAL-SLSA	84368	LEVEL OF PATHOGEN REQUIREMENTS ACHIEVED
SLL	A	9	LAND APPLICATION - SLLA	84369	DESCRIPTION OF PATHOGEN OPTION USED
SLS	A	9	SURFACE DISPOSAL-SLSA	84369	DESCRIPTION OF PATHOGEN OPTION USED
SLS	A	9	SURFACE DISPOSAL-SLSA	84370	VECTOR ATTRACTION REDUCTION ALTERN USED
SLL	A	9	LAND APPLICATION - SLLA	84370	VECTOR ATTRACTION REDUCTION ALTERN USED
SLD	F	9	LANDFILL- SLDF	49030	COMPLIANCE W/PART 258 SLUDGE REQUIREMENT
SLD	P	9	PRODUCTION AND USE - SLDP	39516	POLYCHLORINATED BIPHENYLS (PCBS)
SLD	P	9	PRODUCTION AND USE - SLDP	46390	TOXICITY CHARACTERISTIC LEACHING PROCED.
SLD	P	9	PRODUCTION AND USE - SLDP	49017	ANN. AMT SLUDGE DISPOSED BY OTHER METHOD
SLD	P	9	PRODUCTION AND USE - SLDP	49018	ANNUAL AMT OF SLUDGEINCINERATED
SLD	P	9	PRODUCTION AND USE - SLDP	49019	ANNUAL SLUDGE PRODUCTION, TOTAL
SLD	P	9	PRODUCTION AND USE - SLDP	49020	ANNUAL AMOUNT OF SLUDGE LAND APPLIED
SLD	P	9	PRODUCTION AND USE - SLDP	49021	ANNUAL AMT. SLUDGE DISPOSED SURFACE UNIT
SLD	P	9	PRODUCTION AND USE - SLDP	49022	ANNUAL AMT SLUDGE DISPOSED IN LANDFILL

SLD	P	9	PRODUCTION AND USE - SLDP	49023	ANNUAL AMT SLUDGE TRANSPORTED INTERSTATE

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Query Results

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NPDES: Equal To: TX0053368

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Click on the underlined NPDES value to view detailed reports on the facility.

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Facility Information

FACILITY NAME:	CITY OF BELLS	NPDES:	TX0053368
STREET 1:	U.S. HWY 69 AND FM HWY 1897, N		
CITY:	BELLS	PERMIT ISSUED DATE:	MAY-16-2007
STATE:	TX	PERMIT EXPIRED DATE:	DEC-01-2011
ZIP CODE:	75414		
COUNTY NAME:	GRAYSON	SIC CODE:	4952 SEWERAGE SYSTEMS
REGION:	6	MAPPING INFO:	MAP
MAILING NAME:	CITY OF BELLS		

List of Permitted Discharges

PIPE NUMBER	REPORT DESIGNATOR	PIPE SET QUALIFIER	PIPE DESCRIPTION	PARAMETER CODE	PARAMETER DESCRIPTION
001	A	9	DOMESTIC FACILITY - 001	00300	OXYGEN, DISSOLVED (DO)
001	A	9	DOMESTIC FACILITY - 001	00310	BOD, 5-DAY (20 DEG. C)
SLS	A	9	SURFACE DISPOSAL-SLSA	00400	PH
001	A	9	DOMESTIC FACILITY - 001	00400	PH
001	A	9	DOMESTIC FACILITY - 001	00530	SOLIDS, TOTAL SUSPENDED
SLS	A	9	SURFACE DISPOSAL-SLSA	01003	ARSENIC IN BOTTOM DEPOSITS (DRY WGT)
SLL	A	9	LAND APPLICATION - SLLA	01003	ARSENIC IN BOTTOM DEPOSITS (DRY WGT)
SLS	A	9	SURFACE DISPOSAL-SLSA	01067	NICKEL, TOTAL (AS NI)
SLL	A	9	LAND APPLICATION - SLLA	01148	SELENIUM IN BOTTOM DEPOSITS (DRY WGT)
SLL	A	9	LAND APPLICATION - SLLA	46394	COPPER, TOTAL SLUDGE
SLL	A	9	LAND APPLICATION - SLLA	46395	CADIUM, TOTAL SLUDGE

SLL	A	9	LAND APPLICATION - SLLA	49016	ANNUAL WHOLE SLUDGE APPLICATION RATE
SLS	A	9	SURFACE DISPOSAL-SLSA	49028	UNIT W/LINER/LEACHATE COLLECTION SYSTEM
001	A	9	DOMESTIC FACILITY - 001	50050	FLOW, IN CONDUIT OR THRU TREATMENT PLANT
001	A	9	DOMESTIC FACILITY - 001	50060	CHLORINE, TOTAL RESIDUAL
SLL	A	9	LAND APPLICATION - SLLA	78465	MOLYBDENUM, SLUDGE, TOT, DRY WT. (AS MO)
SLL	A	9	LAND APPLICATION - SLLA	78467	ZINC, SLUDGE, TOTAL, DRY WEIGHT, (AS ZN)
SLL	A	9	LAND APPLICATION - SLLA	78468	LEAD, SLUDGE, TOTAL, DRY WEIGHT (AS PB)
SLL	A	9	LAND APPLICATION - SLLA	78469	NICKEL, SLUDGE, TOT, DRY WEIGHT (AS NI)
SLL	A	9	LAND APPLICATION - SLLA	78471	MERCURY, SLUDGE, TOT DRY WEIGHT (AS HG)
SLL	A	9	LAND APPLICATION - SLLA	78473	CHROMIUM, SLUDGE, TOT, DRY WT. (AS CR)
SLS	A	9	SURFACE DISPOSAL-SLSA	78473	CHROMIUM, SLUDGE, TOT, DRY WT. (AS CR)
SLL	A	9	LAND APPLICATION - SLLA	84367	POLLUTANT TABLE FROM 503.13
SLL	A	9	LAND APPLICATION - SLLA	84368	LEVEL OF PATHOGEN REQUIREMENTS ACHIEVED
SLS	A	9	SURFACE DISPOSAL-SLSA	84368	LEVEL OF PATHOGEN REQUIREMENTS ACHIEVED
SLL	A	9	LAND APPLICATION - SLLA	84369	DESCRIPTION OF PATHOGEN OPTION USED
SLS	A	9	SURFACE DISPOSAL-SLSA	84369	DESCRIPTION OF PATHOGEN OPTION USED
SLS	A	9	SURFACE DISPOSAL-SLSA	84370	VECTOR ATTRACTION REDUCTION ALTERN USED
SLL	A	9	LAND APPLICATION - SLLA	84370	VECTOR ATTRACTION REDUCTION ALTERN USED
SLD	F	9	LANDFILL- SLDF	49030	COMPLIANCE W/PART 258 SLUDGE REQUIREMENT
SLD	P	9	PRODUCTION AND USE - SLDP	39516	POLYCHLORINATED BIPHENYLS (PCBS)
SLD	P	9	PRODUCTION AND USE - SLDP	46390	TOXICITY CHARACTERISTIC LEACHING PROCED.
SLD	P	9	PRODUCTION AND USE - SLDP	49017	ANN. AMT SLUDGE DISPOSED BY OTHER METHOD
SLD	P	9	PRODUCTION AND USE - SLDP	49018	ANNUAL AMT OF SLUDGEINCINERATED
SLD	P	9	PRODUCTION AND USE - SLDP	49019	ANNUAL SLUDGE PRODUCTION, TOTAL
SLD	P	9	PRODUCTION AND USE - SLDP	49020	ANNUAL AMOUNT OF SLUDGE LAND APPLIED
SLD	P	9	PRODUCTION AND USE - SLDP	49021	ANNUAL AMT. SLUDGE DISPOSED SURFACE UNIT
SLD	P	9	PRODUCTION AND USE - SLDP	49022	ANNUAL AMT SLUDGE DISPOSED IN LANDFILL

SLD	P	9	PRODUCTION AND USE - SLDP	49023	ANNUAL AMT SLUDGE TRANSPORTED INTERSTATE

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Facility Registry System (FRS)

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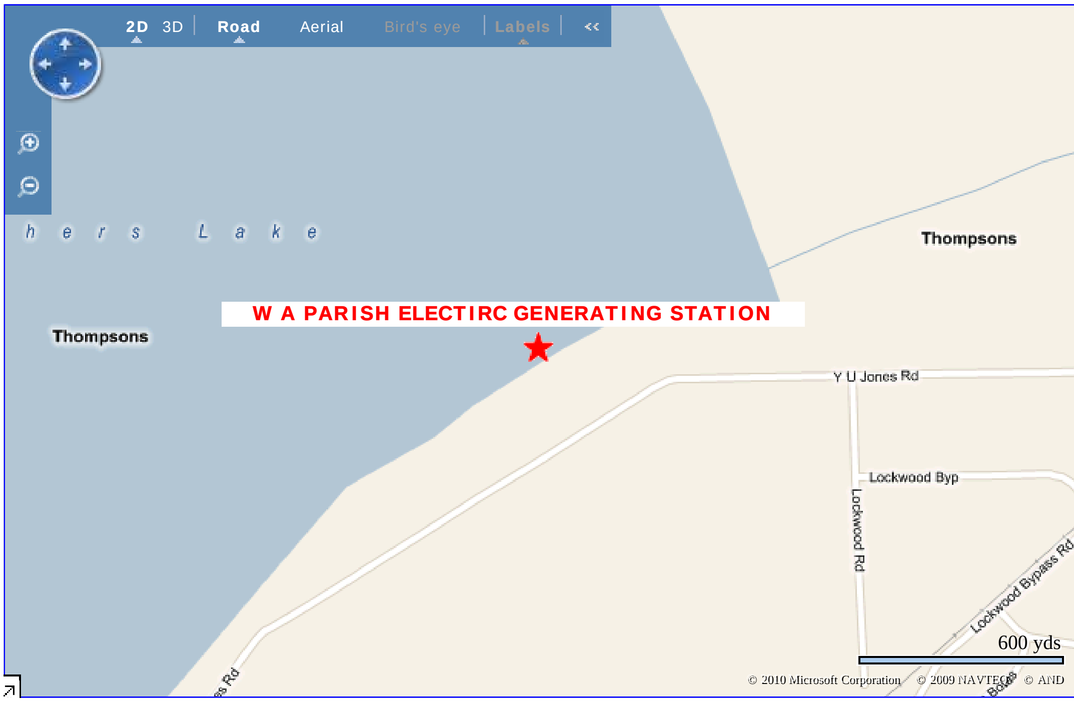
W A PARISH ELECTIRC GENERATING STATION

2500 Y.U. JONES RD.
THOMPSONS, TX 77481
EPA Registry Id: 110000608254



Legend

- Selected Facility
- EPA Facility of Interest
- State/Tribe Facility of Interest

The facility locations displayed come from the FRS Spatial Coordinates tables. They are the best representative locations for the displayed facilities based on the accuracy of the collection method and quality assurance checks performed against each location. The North American Datum of 1983 is used to display all coordinates.

Environmental Interests

Information System	Information System ID	Environmental Interest Type	Data Source	Last Updated Date	Supplemental Environmental Interests:
AIR FACILITY SYSTEM	4815700005	AIR MAJOR ()	AIRS/AFS	07/22/2009	
AIR FACILITY SYSTEM	4815700023	AIR MINOR ()	AIRS/AFS	09/02/2009	
CLEAN AIR MARKETS DIVISION (CAMD) BUSINESS SYSTEMS	3470	AIR PROGRAM	CAMDBS	03/14/2009	
EMISSIONS & GENERATION RESOURCE INTEGRATED DATABASE	3470	ELECTRIC POWER GENERATOR (COAL BASED)	EGRID		
NATIONAL COMPLIANCE DATABASE	I06#19961216059241	COMPLIANCE ACTIVITY	NCDB		
NATIONAL EMISSIONS INVENTORY	NEI8409	CRITERIA AND HAZARDOUS AIR POLLUTANT INVENTORY	NEI		
NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (ICIS-NPDES)	TX0006394	ICIS-NPDES MAJOR	ICIS	12/11/2008	**ICIS-** ENFORCEMENT/COMPLIANCE ACTIVITY
PERMIT COMPLIANCE SYSTEM	TX0006394	NPDES MAJOR	NPDES PERMIT	12/11/2008	
RACT/BACT/LAER CLEARINGHOUSE	2142	AIR MAJOR	RBLC		
RACT/BACT/LAER CLEARINGHOUSE	25131	AIR MAJOR	RBLC		
RACT/BACT/LAER CLEARINGHOUSE	25472	AIR MAJOR	RBLC		
RACT/BACT/LAER CLEARINGHOUSE	25560	AIR MAJOR	RBLC		
RESOURCE CONSERVATION AND RECOVERY ACT INFORMATION SYSTEM	TXD097311849	CORRECTIVE ACTION (ACTIVE)	RCRAINFO	07/15/2009	
RESOURCE CONSERVATION AND RECOVERY ACT INFORMATION SYSTEM	TXD097311849	SQG (ACTIVE)	NOTIFICATION (RCRA)	07/15/2009	
RESOURCE CONSERVATION AND RECOVERY ACT INFORMATION SYSTEM	TXD097311849	TSD (ACTIVE)	NOTIFICATION (RCRA)	07/15/2009	
			RMP		

RISK MANAGEMENT PLAN	100000180895	RMP REPORTER	REPORTING FORM	09/27/2007	
TOXIC RELEASE INVENTORY SYSTEM	77481WPRSHYUJON	TRI REPORTER	TRI REPORTING FORM	06/30/2009	
TEXAS COMMISSION ON ENVIRONMENTAL QUALITY - AGENCY CENTRAL REGISTRY	RN105292197	STATE MASTER	TX-TCEQ ACR		**PERMIT**-TXR05T816 STORMWATER **PERMIT**-TXR05V666 STORMWATER **PERMIT**-TXR05T816 NPDES STORMWATER PERMIT **PERMIT**-TXR05V666 NPDES STORMWATER PERMIT **PCS**-PAR803522 NPDES PERMIT

Additional EPA Reports: MyEnvironment Enforcement and Compliance Cleanups in My Community Site Demographics Watershed Report

Standard Industrial Classification Codes (SIC)

Data Source	SIC Code	Description	Primary
TX-TCEQ ACR	4911	ELECTRIC SERVICES	
PCS	4911	ELECTRIC SERVICES	
NPDES	4911	ELECTRIC SERVICES	
AIRS/AFS	4953	REFUSE SYSTEMS	
TRIS	4911	ELECTRIC SERVICES	
RBLC	4911	ELECTRIC SERVICES	
NCDB	4911	ELECTRIC SERVICES	
CAMDBS	4911	ELECTRIC SERVICES	
AIRS/AFS	4911	ELECTRIC SERVICES	
RBLC	4911	ELECTRIC SERVICES	
RBLC	4911	ELECTRIC SERVICES	
AIRS/AFS	4911	ELECTRIC SERVICES	
TX-TCEQ ACR	4231	TERMINAL AND JOINT TERMINAL MAINTENANCE FACILITIES FOR MOTOR FREIGHT TRANSPORTATION	
NEI	4911	ELECTRIC SERVICES	

National Industry Classification System Codes (NAICS)

Data Source	NAICS Code	Description	Primary
NEI	221112	FOSSIL FUEL ELECTRIC POWER GENERATION.	
TRIS	221119	OTHER ELECTRIC POWER GENERATION.	
TX-TCEQ ACR	221112	FOSSIL FUEL ELECTRIC POWER GENERATION.	
RCRAINFO	221122	ELECTRIC POWER DISTRIBUTION.	
RMP	221112	FOSSIL FUEL ELECTRIC POWER GENERATION.	
TRIS	221112	FOSSIL FUEL ELECTRIC POWER GENERATION.	
CAMDBS	221112	FOSSIL FUEL ELECTRIC POWER GENERATION.	
NEI	221122	ELECTRIC POWER DISTRIBUTION.	

Facility Codes and Flags

EPA Region:	06
Duns Number:	097311849
Congressional District Number:	22
Legislative District Number:	12
HUC Code/Watershed:	12070104 / LOWER BRAZOS
US Mexico Border Indicator:	NO
Federal Facility:	NO
Tribal Land:	NO

Alternative Names

Alternative Name	Source of Data
WASHINGTON PARISH ELECTRIC GENERATING STATION	RBLC
W.A. PARISH ELECTRIC GENERATING STATION	RBLC
HOUSTON INDUSTRIES INCORPORATED	AIR VOLUNTARY SUBMISSION
WASHINGTON PARISH ELECTRIC GENERATING STATION	RBLC
WA PARISH ELECTRIC GENERATIN G STATION	TRI REPORTING FORM
W A PARISH	CAMDBS
W A PARISH ELECTRIC GENERATING STATION	TRI REPORTING FORM
HOUSTON LIGHTING & POWER	NCDB
HOUSTON LIGHTING & POWER	RBLC
W.A. PARISH ELECTRIC GENERATIN G STATION	BATCH ENTRY
RELIANT ENERGY INC	NOTIFICATION (RCRA)
WA PARISH ELECTRIC GENERATING STATION	RBLC
RELIANT ENERGY, INCORPORATED	AIRS/AFS

Facility Mailing Addresses

Affiliation Type	Delivery Point	City Name	State	Postal Code	Information System
MAILING ADDRESS	ATTN: CARL E BURCH	THOMPSONS	TX	77481	NPDES
OPERATOR	PO BOX 4710	HOUSTON	TX	772104710	TX-TCEQ ACR
OPERATOR	1301 MCKINNEY ST STE 2300	HOUSTON	TX	77010	RCRAINFO
OWNER	PO BOX 4710	HOUSTON	TX	77210	RCRAINFO
OWNER/OPERATOR	P.O. BOX 4710	HOUSTON	TX	77210	RMP
FACILITY MAILING ADDRESS	PO BOX 1700	HOUSTON	TX	77251	AIRS/AFS
OPERATOR	PO BOX 4710	HOUSTON	TX	77210	RCRAINFO
OWNOP	3912 BRUMBAUGH RD	NEW ENTERPRISE	PA	16664-0077	TX-TCEQ ACR
MAILING ADDRESS	PO BOX 77	NEW ENTERPRISE	PA	16664-0077	TX-TCEQ ACR
PRIMARY MAILING ADDRESS	ATTN: CARL E BURCH	THOMPSONS	TX	77481	PCS
ALTERNATE MAILING ADDRESS	P.O. BOX 4710	HOUSTON	TX	77210	PCS
FACILITY MAILING ADDRESS	1301 MCKINNEY ST STE 2300	HOUSTON	TX	77010	RCRAINFO
OWNER	1301 MCKINNEY ST	HOUSTON	TX	77010	PCS
PRIMARY CONTACT	1301 MCKINNEY	HOUSTON	TX	77010	CAMDBS
ALTERNATE CONTACT	1301 MCKINNEY	HOUSTON	TX	77010	CAMDBS
PUBLIC CONTACT	PO BOX 1700	HOUSTON	TX	77251	RBLC
MAILING ADDRESS	2500 Y U JONES RD	THOMPSONS	TX	77481	TX-TCEQ ACR
OWNER	1301 MCKINNEY STREET	HOUSTON	TX	77010	NPDES
OWNER	1301 MCKINNEY ST STE 2300	HOUSTON	TX	77010	RCRAINFO
REGULATORY CONTACT	1301 MCKINNEY ST STE 2300	HOUSTON	TX	77010	RCRAINFO
FACILITY MAILING ADDRESS	2500 YU JONES RD	THOMPSONS	TX	77481	TRIS

NRG TEXAS POWER LLC	NPDES PERMIT

Organizations

Affiliation Type	Name	DUNS Number	Information System	Mailing Address
OWNER	NRG TEXAS POWER LLC		NPDES	View
OWNOP	NEW ENTERPRISE STONE & LIME CO., INC.		TX-TCEQ ACR	View
MAILING ADDRESS	NRG TEXAS POWER LLC		NPDES	View
OWNER	NRG TEXAS POWER LLC		PCS	View
OPERATOR	NRG TEXAS POWER LLC		RCRAINFO	View
OWNER1	NRG ENERGY		EGRID	
OWNER/OPERATOR	NRG TEXAS POWER LLC		CAMDBS	
OPERATOR	NRG ENERGY		EGRID	
OWNER	NRG TEXAS POWER LLC		RCRAINFO	View
OPERATOR	NRG TEXAS POWER LLC		RCRAINFO	View
OWNER	NRG TEXAS POWER LLC		RCRAINFO	View
OWNER/OPERATOR	NRG TEXAS POWER LLC		RMP	View
OPERATOR	NRG TEXAS LP	168456049	TX-TCEQ ACR	View
PARENT COMPANY 1	NRG TEXAS POWER LLC	168456049	RMP	
OWNER/OPERATOR		097311849	TRIS	
REGULATORY CONTACT	NRG TEXAS LP		CAMDBS	
PARENT ORGANIZATION	NRG TEXAS POWER LLC	120807255	TRIS	

Contacts

Affiliation Type	Full Name	Office Phone	Information System	Mailing Address
EMERGENCY CONTACT	R. A. OSCO	2813432047	RMP	
PUBLIC CONTACT	DAVID KNOX	7137956106	TRIS	
OWNOP	DONALD L DETWILER	8147662211	TX-TCEQ ACR	View
COMPLIANCE CONTACT	B.C. CARMINE	7132071111	AIRS/AFS	
REGULATORY CONTACT	BEN CARMINE		CAMDBS	
PRIMARY CONTACT	BEN C CARMINE	7137956024	CAMDBS	View
PUBLIC CONTACT	BEN CARMINE		RBLC	View
COMPLIANCE CONTACT	J. FURSTENWER		AIRS/AFS	
REGULATORY CONTACT	CRAIG ECKBERG		CAMDBS	
PUBLIC CONTACT	MR. BRAD HILLAKER		RBLC	
PUBLIC CONTACT	BEN CARMINE	713-945-8191	RBLC	View
COGNIZANT OFFICIAL	KEVIN HOWELL	7137956020	PCS	
PUBLIC CONTACT			RBLC	
REGULATORY CONTACT	BEN CARMINE	7137956024	RCRAINFO	View
RESPONSIBLE PARTY	JOHN KUSH		RMP	
ALTERNATE CONTACT	CRAIG R ECKBERG	7137956208	CAMDBS	View

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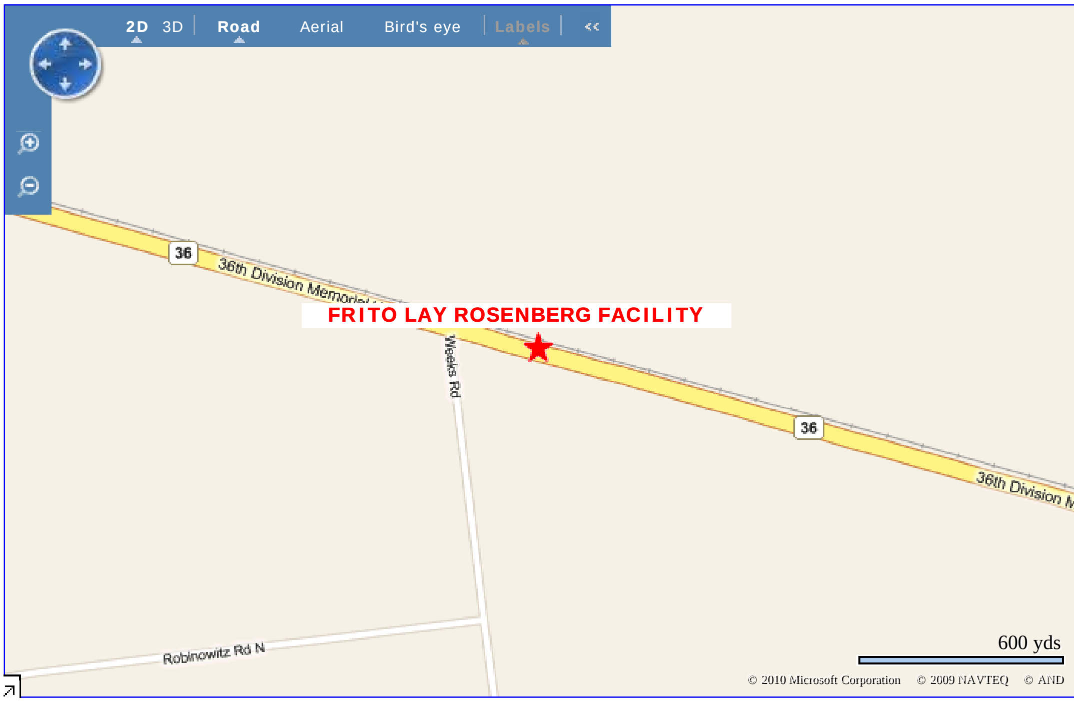
Facility Detail Report

FRS

Report an Error

FRITO LAY ROSENBERG FACILITY

3310 HIGHWAY 36 NORTH
ROSENBERG, TX 77471
EPA Registry Id: 110000599362



Legend

Selected Facility

EPA Facility of Interest

State/Tribe Facility of Interest

The facility locations displayed come from the FRS Spatial Coordinates tables. They are the best representative locations for the displayed facilities based on the accuracy of the collection method and quality assurance checks performed against each location. The North American Datum of 1983 is used to display all coordinates.

Environmental Interests

Information System	Information System ID	Environmental Interest Type	Data Source	Last Updated Date	Supplemental Environmental Interests:
AIR FACILITY SYSTEM	4815700034	AIR MAJOR ()	AIRS/AFS	07/22/2009	
INTEGRATED COMPLIANCE INFORMATION SYSTEM	6680806	FORMAL ENFORCEMENT ACTION	ICIS	09/02/2004	**ICIS**-06-2004-4381 FORMAL ENFORCEMENT ACTION
NATIONAL EMISSIONS INVENTORY	NEITX1570521	CRITERIA AND HAZARDOUS AIR POLLUTANT INVENTORY	NEI		
NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (ICIS-NPDES)	TX0085782	ICIS-NPDES NON-MAJOR	ICIS	10/31/2007	**ICIS**-ENFORCEMENT/COMPLIANCE ACTIVITY
PERMIT COMPLIANCE SYSTEM	TX0085782	NPDES NON-MAJOR	NPDES PERMIT	01/31/2006	
RESOURCE CONSERVATION AND RECOVERY ACT INFORMATION SYSTEM	TXD982306359	SQG (ACTIVE)	NOTIFICATION (RCRA)	07/02/2008	
TOXIC RELEASE INVENTORY SYSTEM	77471FRTLY3310H	TRI REPORTER	TRI REPORTING FORM	06/30/2009	
					REGISTRATION-0790169 COMMUNITY WATER SYSTEM **REGISTRATION**-0790169 PUBLIC WATER SYSTEM/SUPPLY **PERMIT**-1104 AIR OPERATING PERMITS **PERMIT**-1104 AIR PROGRAM **SOLID WASTE REGISTRA**-32497 HAZARDOUS WASTE PROGRAM **SOLID WASTE REGISTRA**-32497 INDUSTRIAL AND HAZARDOUS

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY - AGENCY CENTRAL REGISTRY	RN100219229	STATE MASTER	TX-TCEQ ACR		WASTE GENERATION **REGISTRATION**-42402 PETROLEUM STORAGE TANK REGISTRATION **REGISTRATION**-42402 UNDERGROUND STORAGE TANK PROGRAM **PERMIT**-47581 AIR NEW SOURCE PERMITS **PERMIT**-47581 AIR PROGRAM **AFS NUM**-4815700034 AIR NEW SOURCE PERMITS **AFS NUM**-4815700034 AIR PROGRAM **REGISTRATION**-76013 AIR NEW SOURCE PERMITS **REGISTRATION**-76013 AIR PROGRAM **REGISTRATION**-76240 AIR NEW SOURCE PERMITS **REGISTRATION**-76240 AIR PROGRAM **PERMIT**-7727 AIR NEW SOURCE PERMITS **PERMIT**-7727 AIR PROGRAM **ACCOUNT NUMBER**-FG0052I AIR NEW SOURCE PERMITS **ACCOUNT NUMBER**-FG0052I AIR OPERATING PERMITS **ACCOUNT NUMBER**-FG0052I AIR PROGRAM **ACCOUNT NUMBER**-FG0052I AIR PROGRAM **EPA ID**-TX0085782 NPDES PERMIT **EPA ID**-TX0085782 WASTEWATER **PERMIT**-TX0085782 NPDES PERMIT **PERMIT**-TX0085782 WASTEWATER **EPA ID**-TXD982306359 HAZARDOUS WASTE PROGRAM **EPA ID**-TXD982306359 INDUSTRIAL AND HAZARDOUS WASTE GENERATION **PERMIT**-TXR05L343 NPDES STORMWATER PERMIT **PERMIT**-TXR05L343 STORMWATER **PERMIT**-WQ0002443000 NPDES PERMIT **PERMIT**-WQ0002443000 WASTEWATER **ACCOUNT NUMBER**-FG0052I AIR EMISSION INVENTORY

Additional EPA Reports: MyEnvironment Enforcement and Compliance Site Demographics Watershed Report

Standard Industrial Classification Codes (SIC)

Data Source	SIC Code	Description	Primary
NPDES	2096	POTATO CHIPS, CORN CHIPS, AND SIMILAR SNACKS	
AIRS/AFS	2099	FOOD PREPARATIONS, NOT ELSEWHERE CLASSIFIED	
NEI	2096	POTATO CHIPS, CORN CHIPS, AND SIMILAR SNACKS	
TX-TCEQ ACR	2099	FOOD PREPARATIONS, NOT ELSEWHERE CLASSIFIED	
PCS	2096	POTATO CHIPS, CORN CHIPS, AND SIMILAR SNACKS	
AIRS/AFS	2096	POTATO CHIPS, CORN CHIPS, AND SIMILAR SNACKS	
TX-TCEQ ACR	2096	POTATO CHIPS, CORN CHIPS, AND SIMILAR SNACKS	
TRIS	2096	POTATO CHIPS, CORN CHIPS, AND SIMILAR SNACKS	

Facility Codes and Flags

National Industry Classification System Codes (NAICS)

Data Source	NAICS Code	Description	Primary
TX-TCEQ ACR	311999	ALL OTHER MISCELLANEOUS FOOD MANUFACTURING.	
TRIS	311919	OTHER SNACK FOOD MANUFACTURING.	
TX-TCEQ ACR	311919	OTHER SNACK FOOD MANUFACTURING.	
NEI	311919	OTHER SNACK FOOD MANUFACTURING.	
RCRAINFO	311999	ALL OTHER MISCELLANEOUS FOOD MANUFACTURING.	
FRS	311919	OTHER SNACK FOOD MANUFACTURING.	

Facility Mailing Addresses

Affiliation Type	Delivery Point	City Name	State	Postal Code	Information System
PRIMARY MAILING ADDRESS	3310 HIGHWAY 36 NORTH	ROSENBERG	TX	77471	PCS
OWN	1735 MARKET ST FL 12	PHILADELPHIA	PA	19103-7505	TX-TCEQ ACR
	3310 HIGHWAY				TX-TCEQ

EPA Region:	06
Duns Number:	102685203
Congressional District Number:	22
Legislative District Number:	12
HUC Code/Watershed:	12070104 / LOWER BRAZOS
US Mexico Border Indicator:	NO
Federal Facility:	NO
Tribal Land:	NO

Alternative Names

Alternative Name	Source of Data
FRITO-LAY, INCORPORATED	NPDES PERMIT
FRITO-LAY, INC. ROSENBERG PLANT	ICIS

Organizations

Affiliation Type	Name	DUNS Number	Information System	Mailing Address
OWNER	FRITO-LAY INC		PCS	View
OWNER	FRITO-LAY INC		RCRAINFO	View
OWNER OPERATOR	FRITO-LAY, INC.	008116006	TX-TCEQ ACR	View
OWNER	FRITO-LAY INC		RCRAINFO	View
MAILING ADDRESS	FRITO-LAY INC		NPDES	View
OWNER/OPERATOR		102685203	TRIS	
OPERATOR	FRITO-LAY INC		RCRAINFO	View
OPERATOR	FRITO-LAY INC		RCRAINFO	View
OWNER/OPERATOR		102685203	AIRS/AFS	
OWNER	FRITO-LAY INC		NPDES	View
OWNER	FRITO-LAY INC		RCRAINFO	View
OPERATOR	FRITO-LAY INC		RCRAINFO	View
PARENT ORGANIZATION	PEPSICO	001287762	TRIS	

MAILING ADDRESS	36 N	ROSENBERG	TX	774719716	ACR
OWNER	7701 LEGACY DR	PLANO	TX	75024	NPDES
ALTERNATE MAILING ADDRESS	3310 HIGHWAY 36 NORTH	ROSENBERG	TX	77471	PCS
FACILITY MAILING ADDRESS	3310 HIGHWAY 36 N	ROSENBERG	TX	77471	RCRAINFO
REGULATORY CONTACT	3310 HIGHWAY 36 N	ROSENBERG	TX	77471	RCRAINFO
OPERATOR	3310 HIGHWAY 36 N	ROSENBERG	TX	77471	RCRAINFO
OWNER	3310 HIGHWAY 36 N	ROSENBERG	TX	77471	RCRAINFO
OWNER OPERATOR	3310 HIGHWAY 36 N	ROSENBERG	TX	774719716	TX-TCEQ ACR
FACILITY MAILING ADDRESS	3310 HWY 36 N	ROSENBERG	TX	77471	TRIS
FACILITY MAILING ADDRESS	3310 HWY 36 NORTH	ROSENBERG	TX	77471	AIRS/AFS
OWNOP	1801 MARKET ST	PHILADELPHIA	PA	19103-1628	TX-TCEQ ACR
OWN	1801 MARKET ST	PHILADELPHIA	PA	19103-1628	TX-TCEQ ACR
MAILING ADDRESS	3310 HIGHWAY 36 NORTH	ROSENBERG	TX	77471	NPDES
OWNER	7701 LEGACY DRIVE	PLANO	TX	75024	PCS

Contacts

Affiliation Type	Full Name	Office Phone	Information System	Mailing Address
COMPLIANCE CONTACT	ANTHONY PROVENZANO	7132321527	AIRS/AFS	
OWNOP	JAMES FIDLER	2159773000	TX-TCEQ ACR	View
OWN	KATHLEEN K MCCANEY	2152468513	TX-TCEQ ACR	View
COGNIZANT OFFICIAL	KARL SCHRAER, VP OPERATIONS	9724072650	PCS	
REGULATORY CONTACT	JEFF ELLIOTT	2812321172	RCRAINFO	View
PUBLIC CONTACT	LYNN MARKLEY	9142533059	TRIS	
OWN	JAMES FIDLER	2159773000	TX-TCEQ ACR	View

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U.S. ENVIRONMENTAL PROTECTION AGENCY

Facility Registry System (FRS)

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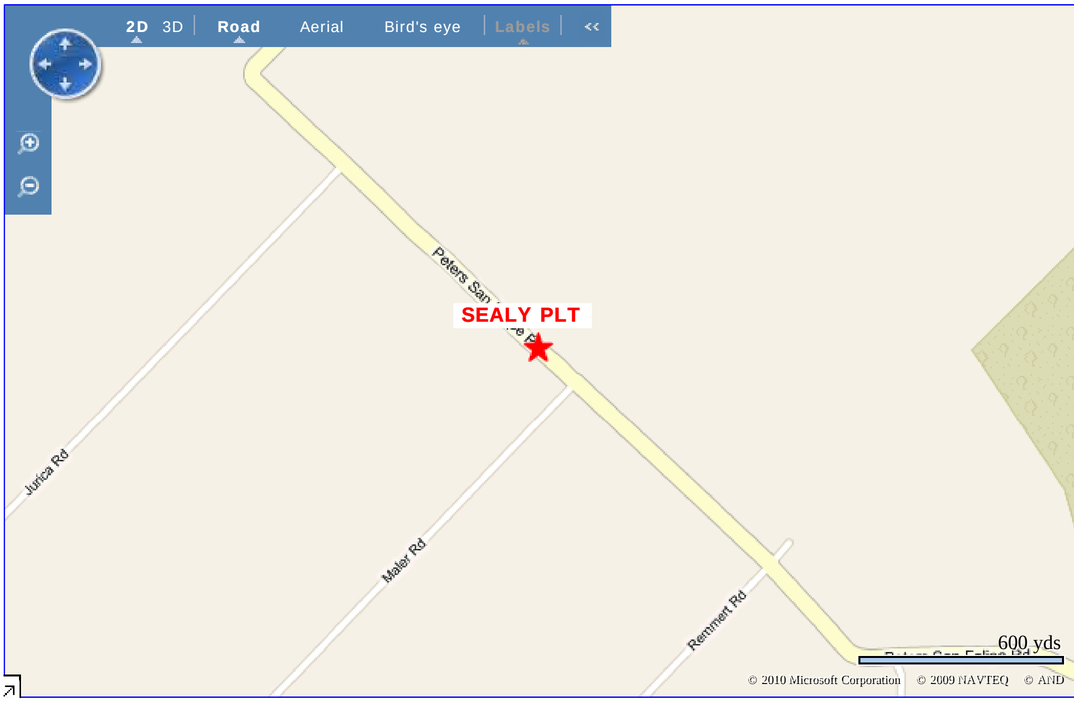
Facility Detail Report

FRS

Report an Error

SEALY PLT

6005 PETERS SAN FELIPE ROAD
SEALY, TX 77474
EPA Registry Id: 110017424027



Legend

- Selected Facility
- EPA Facility of Interest
- State/Tribe Facility of Interest

The facility locations displayed come from the FRS Spatial Coordinates tables. They are the best representative locations for the displayed facilities based on the accuracy of the collection method and quality assurance checks performed against each location. The North American Datum of 1983 is used to display all coordinates.

Environmental Interests

Information System	Information System ID	Environmental Interest Type	Data Source	Last Updated Date	Supplemental Environmental Interests:
AIR FACILITY SYSTEM	4801500005	AIR MAJOR ()	AIRS/AFS	07/22/2009	
NATIONAL EMISSIONS INVENTORY	NEI12041	CRITERIA AND HAZARDOUS AIR POLLUTANT INVENTORY	NEI		
RACT/BACT/LAER CLEARINGHOUSE	2308	AIR MAJOR	RBLC		
RESOURCE CONSERVATION AND RECOVERY ACT INFORMATION SYSTEM	TXR000017343	UNSPECIFIED UNIVERSE (INACTIVE)	RCRAINFO	05/14/2008	
TOXIC RELEASE INVENTORY SYSTEM	77474CMBRC562PE	TRI REPORTER	TRI REPORTING FORM	06/29/2009	
					REGISTRATION-0080036 PUBLIC WATER SYSTEM/SUPPLY **PERMIT**-1149 AIR OPERATING PERMITS **AFS NUM**-4801500005 AIR NEW SOURCE PERMITS **PERMIT**-9540 AIR NEW SOURCE PERMITS **ACCOUNT NUMBER**-AH0039F AIR NEW SOURCE PERMITS **ACCOUNT NUMBER**-AH0039F AIR OPERATING PERMITS **PERMIT**-TPDES0116998 WASTEWATER **PERMIT**-TXR05N630 STORMWATER **PERMIT**-WQ0003882000

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY - AGENCY CENTRAL REGISTRY	RN100220672	STATE MASTER	TX-TCEQ ACR		WASTEWATER **PERMIT**-TPDES0116998 NPDES PERMIT **ACCOUNT NUMBER**-AH0039F AIR PROGRAM **PERMIT**-1149 AIR PROGRAM **PERMIT**-9540 AIR PROGRAM **REGISTRATION**-0080036 COMMUNITY WATER SYSTEM **PERMIT**-TXR05N630 NPDES STORMWATER PERMIT **AFS NUM**-4801500005 AIR PROGRAM **ACCOUNT NUMBER**-AH0039F AIR PROGRAM **PERMIT**-WQ0003882000 NPDES PERMIT
TEXAS COMMISSION ON ENVIRONMENTAL QUALITY - AGENCY CENTRAL REGISTRY	RN102094802	STATE MASTER	TX-TCEQ ACR		**PERMIT**-TPDES0099899 WASTEWATER **PERMIT**-TX0099899 WASTEWATER **PERMIT**-WQ0013192001 WASTEWATER **PERMIT**-TX0099899 NPDES PERMIT **PERMIT**-TPDES0099899 NPDES PERMIT **PERMIT**-WQ0013192001 NPDES PERMIT

Additional EPA Reports: MyEnvironment Enforcement and Compliance Site Demographics Watershed Report

Standard Industrial Classification Codes (SIC)

Data Source	SIC Code	Description	Primary
TX-TCEQ ACR	3251	BRICK AND STRUCTURAL CLAY TILE	
TRIS	1459	CLAY, CERAMIC, AND REFRACTORY MINERALS, NOT ELSEWHERE CLASSIFIED	
TRIS	3251	BRICK AND STRUCTURAL CLAY TILE	
NEI	3251	BRICK AND STRUCTURAL CLAY TILE	
FRS	3251	BRICK AND STRUCTURAL CLAY TILE	
TX-TCEQ ACR	4952	SEWERAGE SYSTEMS	
AIRS/AFS	3251	BRICK AND STRUCTURAL CLAY TILE	

National Industry Classification System Codes (NAICS)

Data Source	NAICS Code	Description	Primary
RCRAINFO	327121	BRICK AND STRUCTURAL CLAY TILE MANUFACTURING.	
NEI	327121	BRICK AND STRUCTURAL CLAY TILE MANUFACTURING.	
FRS	212325	CLAY AND CERAMIC AND REFRACTORY MINERALS MINING.	
TRIS	327121	BRICK AND STRUCTURAL CLAY TILE MANUFACTURING.	
TX-TCEQ ACR	221320	SEWAGE TREATMENT FACILITIES.	

Facility Codes and Flags

EPA Region:	06
Duns Number:	
Congressional District Number:	
Legislative District Number:	12
HUC Code/Watershed:	12070104 / LOWER BRAZOS
US Mexico Border Indicator:	NO
Federal Facility:	NO
Tribal Land:	NO

Facility Mailing Addresses

Affiliation Type	Delivery Point	City Name	State	Postal Code	Information System
FACILITY MAILING ADDRESS	3024 ACM BRICK PLAZA	FORT WORTH	TX	76109	TRIS
FACILITY MAILING ADDRESS	P.O. BOX 425	FORT WORTH	TX	76101	AIRS/AFS
OWNER	PO BOX 397	SEALY	TX	77474	RCRAINFO
OPERATOR	PO BOX 425	FORT WORTH	TX	76101	RCRAINFO
MAILING ADDRESS	6005 PETERS SAN FELIPE RD	SEALY	TX	774745925	TX-TCEQ ACR
OWNER OPERATOR	PO BOX 425	FORT WORTH	TX	761010425	TX-TCEQ ACR
OPERATOR	PO BOX 397	SEALY	TX	77474	RCRAINFO
OWNER	PO BOX 425	FORT WORTH	TX	76101	RCRAINFO
REGULATORY CONTACT	PO BOX 425	FORT WORTH	TX	76101	RCRAINFO
FACILITY MAILING ADDRESS	PO BOX 425	FORT WORTH	TX	76101	RCRAINFO
OWNER	PO BOX 425	FORT WORTH	TX	761010425	TX-TCEQ ACR

Alternative Names

Alternative Name	Source of Data
ACME BRICK CO.	RBLC
ACME BRICK COMPANY	AIRS/AFS
ACME BRICK CO. SAN FELIPE PLANT	TRI REPORTING FORM
ACME BRICK CO.	TRI REPORTING FORM
ACME BRICK CO. SAN FELIPE PLANT	TRIS

Organizations

Affiliation Type	Name	DUNS Number	Information System	Mailing Address
OWNER	ACME BRICK COMPANY		TX-TCEQ ACR	View

Contacts

		Office	Information	Mailing

OPERATOR	ACME BRICK COMPANY		RCRAINFO	View
OWNER/OPERATOR		154752588	AIRS/AFS	
OWNER OPERATOR	ACME BRICK COMPANY		TX-TCEQ ACR	View
OWNER	ACME BRICK COMPANY		RCRAINFO	View
OWNER/OPERATOR		008018772	TRIS	
OPERATOR	ACME BRICK COMPANY		RCRAINFO	View
OWNER	ACME BRICK COMPANY		RCRAINFO	View
PARENT ORGANIZATION	ACME BRICK	008018772	TRIS	

Affiliation Type	Full Name	Phone	System	Address
COMPLIANCE CONTACT	MR MIKE OCONNOR	8173324101	AIRS/AFS	
PUBLIC CONTACT			RBLC	
PUBLIC CONTACT	JASON PENCE	8173324101	TRIS	
REGULATORY CONTACT	BOB SIMMONS	9188340618	RCRAINFO	View

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Query Results

Report an Error

AIRS/AFS

SCSC ID: Equal To: 4814700001|

Results are based on data extracted on OCT-19-2009

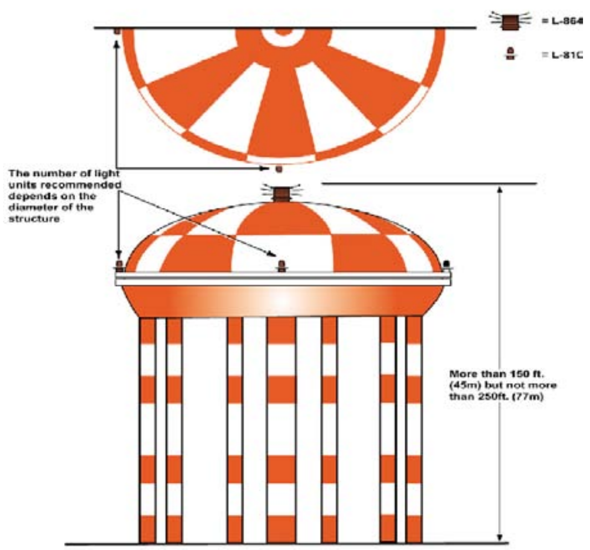
Total Number of Facilities Displayed: 0

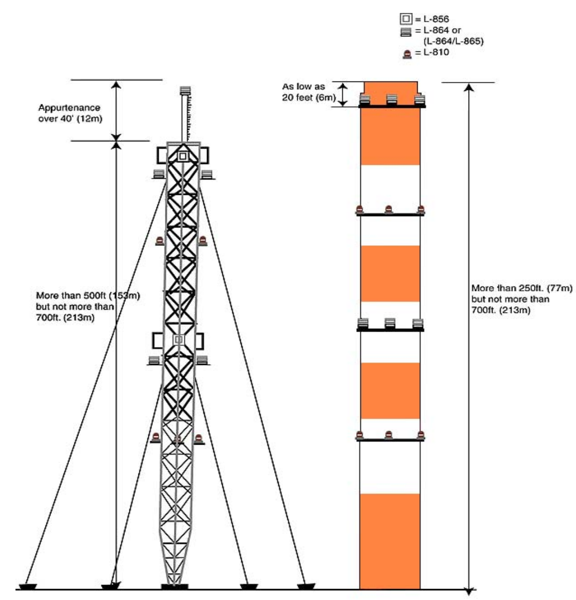
U.S. Department
of Transportation
**Federal Aviation
Administration**

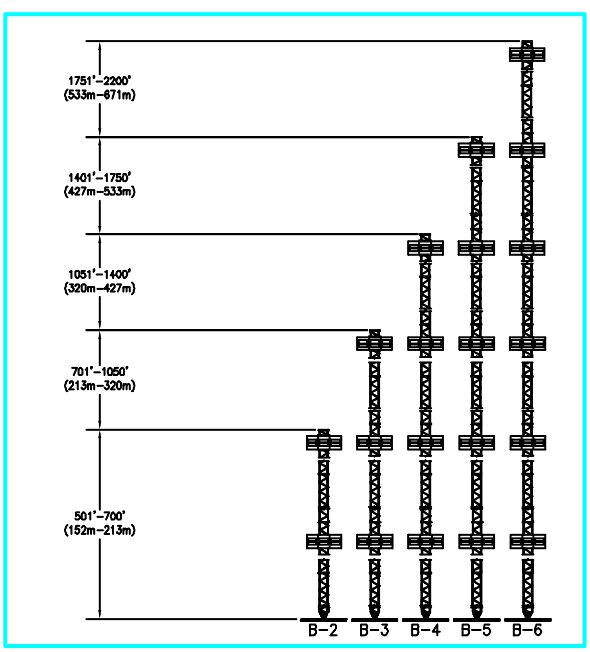
ADVISORY CIRCULAR

AC 70/7460-1K

Obstruction Marking and Lighting







Effective: 2/1/07 **Initiated by: System Operations Services**

Subject: CHANGE 2 TO OBSTRUCTION MARKING AND LIGHTING | **Date:** 2/1/07 | **Initiated by:** AJR-33 | **AC No.:** 70/7460-1K | **Change:** 2

1. PURPOSE. This change amends the Federal Aviation Administration's standards for marking and lighting structures to promote aviation safety. The change number and date of the change material are located at the top of the page.

2. EFFECTIVE DATE. This change is effective February 1, 2007.

3. EXPLANATION OF CHANGES.

a. Table of Contents. Change pages i through iii.

b. Page 1. Paragraph 1. **Reporting Requirements**. Incorporated the word "Title" in reference to the 14 Code of Federal Regulations (14 CFR part 77). FAA Regional Air Traffic Division office to read Obstruction Evaluation service (OES). FAA website to read http://oeaaa.faa.gov.

c. Page 1. Paragraph 4. **Supplemental Notice Requirement** (subpart b). FAA Regional Air Traffic Division office to read OES.

d. Page 1. Paragraph 5. **Modifications and Deviations** (subpart a). FAA Regional Air Traffic Division office to read OES.

e. Page 1. Paragraph 5. **Modifications and Deviations** (subpart c). FAA Regional office to read OES.

f. Page 2. Paragraph 5. **Modifications and Deviations** (subpart d). Removed period to create one sentence.

g. Page 2. Paragraph 7. **Metric Units**. And to read however.

h. Page 3. Paragraph 23. **Light Failure Notification** (subpart b). Nearest to read appropriate. FAA's website to read web. Website www.faa.gov/ats/ata/ata400 to read http://www.afss.com.

i. Page 4. Paragraph 24. **Notification of Restoration**. Removed AFSS.

j. Page 5. Paragraph 32. **Paint Standards**. Removed a comma after "Since".

k. Page 5. Paragraph 33. **Paint Patterns** (subpart d. **Alternate Bands**). Removed number 6. Number 7 to read number 6.

l. Page 9. Paragraph 41. **Standards**. TASC to read OTS. SVC-121.23 to read M-30.

m. Page 14. Paragraph 55. **Wind Turbine Structures**. Removed. The paragraph numbers that follow have been changed accordingly.

n. Page 18. Paragraph 65. **Wind Turbine Structures**. Removed. The paragraph numbers that follow have been changed accordingly.

o. Page 20. Paragraph 77. **Radio and Television Towers and Similar Skeletal Structures**. Excluding to read including.

p. Page 23. Paragraph 85. **Wind Turbine Structures**. Removed. The paragraph number that follows has been changed accordingly.

q. Page 33-34. Chapter 13. **Marking and Lighting Wind Turbine Farms**. Added.

r. Page A1-3. Appendix 1. Verbiage removed under first structure.

Nancy B Kalinowski

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Director, System Operations Airspace and Aeronautical Information Management

PAGE CONTROL CHART

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CHAPTER 1. ADMINISTRATIVE AND GENERAL PROCEDURES

1. REPORTING REQUIREMENTS

A sponsor proposing any type of construction or alteration of a structure that may affect the National Airspace System (NAS) is required under the provisions of Title 14 Code of Federal Regulations (14 CFR part 77) to notify the FAA by completing the Notice of Proposed Construction or Alteration form (FAA Form 7460-1). The form should be sent to the Obstruction Evaluation service (OES). Copies of FAA Form 7460-1 may be obtained from OES, Airports District Office or FAA Website at http://oeaaa.faa.gov.

2. PRECONSTRUCTION NOTICE

The notice must be submitted:

a. At least 30 days prior to the date of proposed construction or alteration is to begin.

b. On or before the date an application for a construction permit is filed with the Federal Communications Commission (FCC). (The FCC advises its applicants to file with the FAA well in advance of the 30-day period in order to expedite FCC processing.)

3. FAA ACKNOWLEDGEMENT

The FAA will acknowledge, in writing, receipt of each FAA Form 7460-1 notice received.

4. SUPPLEMENTAL NOTICE REQUIREMENT

a. If required, the FAA will include a FAA Form 7460-2, Notice of Actual Construction or Alteration, with a determination.

b. FAA Form 7460-2 Part 1 is to be completed and sent to the FAA at least 48 hours prior to starting the actual construction or alteration of a structure. Additionally, Part 2 shall be submitted no later than 5 days after the structure has reached its greatest height. The form should be sent to the OES.

c. In addition, supplemental notice shall be submitted upon abandonment of construction.

d. Letters are acceptable in cases where the construction/alteration is temporary or a proposal is abandoned. This notification process is designed to permit the FAA the necessary time to change affected procedures and/or minimum flight altitudes, and to otherwise alert airmen of the structure's presence.

Note-
NOTIFICATION AS REQUIRED IN THE DETERMINATION IS CRITICAL TO AVIATION SAFETY.

5. MODIFICATIONS AND DEVIATIONS

a. Requests for modification or deviation from the standards outlined in this AC must be submitted to the OES. The sponsor is responsible for adhering to approved marking and/or lighting limitations, and/or recommendations given, and should notify the FAA and FCC (for those structures regulated by the FCC) prior to removal of marking and/or lighting. A request received after a determination is issued may require a new study and could result in a new determination.

b. ***Modifications***. Modifications will be based on whether or not they impact aviation safety. Examples of modifications that may be considered:

1. ***Marking and/or Lighting Only a Portion of an Object.*** The object may be so located with respect to other objects or terrain that only a portion of it needs to be marked or lighted.

2. ***No Marking and/or Lighting***. The object may be so located with respect to other objects or terrain, removed from the general flow of air traffic, or may be so conspicuous by its shape, size, or color that marking or lighting would serve no useful purpose.

3. ***Voluntary Marking and/or Lighting***. The object may be so located with respect to other objects or terrain that the sponsor feels increased conspicuity would better serve aviation safety. Sponsors who desire to voluntarily mark and/or light their structure should request the proper marking and/or lighting from the FAA to ensure no aviation safety issues are impacted.

4. ***Marking or Lighting an Object in Accordance with the Standards for an Object of Greater Height or Size.*** The object may present such an extraordinary hazard potential that higher standards may be recommended for increased conspicuity to ensure the safety to air navigation.

c. ***Deviations***. The OES conducts an aeronautical study of the proposed deviation(s) and forwards its recommendation to FAA headquarters in Washington, DC, for final approval. Examples of deviations that may be considered:

1. Colors of objects.

2. Dimensions of color bands or rectangles.

3. Colors/types of lights.

4. Basic signals and intensity of lighting.

5. Night/day lighting combinations.

6. Flash rate.

d. The FAA strongly recommends that owners become familiar with the different types of lighting systems and to specifically request the type of lighting system desired when submitting FAA Form 7460-1. (This request should be noted in "item 2.D" of the FAA form.) Information on these systems can be found in Chapter 12, Table 4 of this AC. While the FAA will make every effort to accommodate the structure sponsor's request, sponsors should also request information from system manufacturers in order to determine which system best meets their needs based on purpose, installation, and maintenance costs.

6. ADDITIONAL NOTIFICATION

Sponsors are reminded that any change to the submitted information on which the FAA has based its determination, including modification, deviation or optional upgrade to white lighting on structures which are regulated by the FCC, must also be filed with the FCC prior to making the change for proper authorization and annotations of obstruction marking and lighting. These structures will be subject to inspection and enforcement of marking and lighting requirements by the FCC. FCC Forms and Bulletins can be obtained from the FCC's National Call Center at 1-888-CALL-FCC (1-888-225-5322). Upon completion of the actual change, notify the Aeronautical Charting office at:

NOAA/NOS Aeronautical Charting Division Station 5601, N/ACC113 1305 East-West Highway Silver Spring, MD 20910-3233

7. METRIC UNITS

To promote an orderly transition to metric units, sponsors should include both English and metric (SI units) dimensions. The metric conversions may not be exact equivalents, however, until there is an official changeover to the metric system, the English dimensions will govern.

CHAPTER 2. GENERAL

20. STRUCTURES TO BE MARKED AND LIGHTED

Any temporary or permanent structure, including all appurtenances, that exceeds an overall height of 200 feet (61m) above ground level (AGL) or exceeds any obstruction standard contained in 14 CFR part 77, should normally be marked and/or lighted. However, an FAA aeronautical study may reveal that the absence of marking and/or lighting will not impair aviation safety. Conversely, the object may present such an extraordinary hazard potential that higher standards may be recommended for increased conspicuity to ensure safety to air navigation. Normally outside commercial lighting is not considered sufficient reason to omit recommended marking and/or lighting. Recommendations on marking and/or lighting structures can vary depending on terrain features, weather patterns, geographic location, and in the case of wind turbines, number of structures and overall layout of design. The FAA may also recommend marking and/or lighting a structure that does not exceed 200 (61m) feet AGL or 14 CFR part 77 standards because of its particular location.

21. GUYED STRUCTURES

The guys of a 2,000-foot (610m) skeletal tower are anchored from 1,600 feet (488m) to 2,000 feet (610m) from the base of the structure. This places a portion of the guys 1,500 feet (458m) from the tower at a height of between 125 feet (38m) to 500 feet (153m) AGL. 14 CFR part 91, section 119, requires pilots, when operating over other than congested areas, to remain at least 500 feet (153m) from man-made structures. Therefore, the tower must be cleared by 2,000 feet (610m) horizontally to avoid all guy wires. Properly maintained marking and lighting are important for increased conspicuity since the guys of a structure are difficult to see until aircraft are dangerously close.

22. MARKING AND LIGHTING EQUIPMENT

Considerable effort and research have been expended in determining the minimum marking and lighting systems or quality of materials that will produce an acceptable level of safety to air navigation. The FAA will recommend the use of only those marking and lighting systems that meet established technical standards. While additional lights may be desirable to identify an obstruction to air navigation and may, on occasion be recommended, the FAA will recommend minimum standards in the interest of safety, economy, and related concerns. Therefore, to provide an adequate level of safety, obstruction lighting systems should be installed, operated, and maintained in accordance with the recommended standards herein.

23. LIGHT FAILURE NOTIFICATION

a. Sponsors should keep in mind that conspicuity is achieved only when all recommended lights are working. Partial equipment outages decrease the margin of safety. Any outage should be corrected as soon as possible. Failure of a steady burning side or intermediate light should be corrected as soon as possible, but notification is not required.

b. Any failure or malfunction that lasts more than thirty (30) minutes and affects a top light or flashing obstruction light, regardless of its position, should be reported immediately to the appropriate flight service station (FSS) so a Notice to Airmen (NOTAM) can be issued. Toll-free numbers for FSS are listed in most telephone books or on the web at http://www.afss.com. This report should contain the following information:

1. Name of persons or organizations reporting light failures including any title, address, and telephone number.

2. The type of structure.

3. Location of structure (including latitude and longitude, if known, prominent structures, landmarks, etc.).

4. Height of structure above ground level (AGL)/above mean sea level (AMSL), if known.

5. A return to service date.

6. FCC Antenna Registration Number (for structures that are regulated by the FCC).

Note-
1. *When the primary lamp in a double obstruction light fails, and the secondary lamp comes on, no report is required. However, when one of the lamps in an incandescent L-864 flashing red beacon fails, it should be reported.*

2. *After 15 days, the NOTAM is automatically deleted from the system. The sponsor is responsible for calling the nearest FSS to extend the outage date or to report a return to service date.*

24. NOTIFICATION OF RESTORATION

As soon as normal operation is restored, notify the same FSS that received the notification of failure. The FCC advises that noncompliance with notification procedures could subject its sponsor to penalties or monetary forfeitures.

25. FCC REQUIREMENT

FCC licensees are required to file an environmental assessment with the Commission when seeking authorization for the use of the high intensity flashing white lighting system on structures located in residential neighborhoods, as defined by the applicable zoning law.

CHAPTER 3. MARKING GUIDLINES

30. PURPOSE

This chapter provides recommended guidelines to make certain structures conspicuous to pilots during daylight hours. One way of achieving this conspicuity is by painting and/or marking these structures. Recommendations on marking structures can vary depending on terrain features, weather patterns, geographic location, and in the case of wind turbines, number of structures and overall layout of design.

31. PAINT COLORS

Alternate sections of aviation orange and white paint should be used as they provide maximum visibility of an obstruction by contrast in colors.

32. PAINT STANDARDS

The following standards should be followed. To be effective, the paint used should meet specific color requirements when freshly applied to a structure. Since all outdoor paints deteriorate with time and it is not practical to give a maintenance schedule for all climates, surfaces should be repainted when the color changes noticeably or its effectiveness is reduced by scaling, oxidation, chipping, or layers of contamination.

a. ***Materials and Application***. Quality paint and materials should be selected to provide extra years of service. The paint should be compatible with the surfaces to be painted, including any previous coatings, and suitable for the environmental conditions. Surface preparation and paint application should be in accordance with manufacturer's recommendations.

Note-
In-Service Aviation Orange Color Tolerance Charts are available from private suppliers for determining when repainting is required. The color should be sampled on the upper half of the structure, since weathering is greater there.

b. ***Surfaces Not Requiring Paint***. Ladders, decks, and walkways of steel towers and similar structures need not be painted if a smooth surface presents a potential hazard to maintenance personnel. Paint may also be omitted from precision or critical surfaces if it would have an adverse effect on the transmission or radiation characteristics of a signal. However, the overall marking effect of the structure should not be reduced.

c. ***Skeletal Structures***. Complete all marking/painting prior to or immediately upon completion of construction. This applies to catenary support structures, radio and television towers, and similar skeletal structures. To be effective, paint should be applied to all inner and outer surfaces of the framework.

33. PAINT PATTERNS

Paint patterns of various types are used to mark structures. The pattern to be used is determined by the size and shape of the structure. The following patterns are recommended.

a. ***Solid Pattern***. Obstacles should be colored aviation orange if the structure has both horizontal and vertical dimensions not exceeding 10.5 feet (3.2m).

b. ***Checkerboard Pattern***. Alternating rectangles of aviation orange and white are normally displayed on the following structures:

1. Water, gas, and grain storage tanks.

2. Buildings, as required.

3. Large structures exceeding 10.5 feet (3.2m) across having a horizontal dimension that is equal to or greater than the vertical dimension.

c. ***Size of Patterns***. Sides of the checkerboard pattern should measure not less than 5 feet (1.5m) or more than 20 feet (6m) and should be as nearly square as possible. However, if it is impractical because of the size or shape of a structure, the patterns may have sides less than 5 feet (1.5m). When possible, corner surfaces should be colored orange.

d. ***Alternate Bands***. Alternate bands of aviation orange and white are normally displayed on the following structures:

1. Communication towers and catenary support structures.

2. Poles.

3. Smokestacks.

4. Skeletal framework of storage tanks and similar structures.

5. Structures which appear narrow from a side view, that are 10.5 feet (3.2m) or more across and the horizontal dimension is less than the vertical dimension.

6. Coaxial cable, conduits, and other cables attached to the face of a tower.

e. ***Color Band Characteristics***. Bands for structures of any height should be:

1. Equal in width, provided each band is not less than $1^1/_2$ feet (0.5m) or more than 100 feet (31m) wide.

2. Perpendicular to the vertical axis with the bands at the top and bottom ends colored orange.

3. An odd number of bands on the structure.

4. Approximately one-seventh the height if the structure is 700 feet (214m) AGL or less. For each additional 200 feet (61m) or fraction thereof, add one (1) additional orange and one (1) additional white band.

5. Equal and in proportion to the structure's height AGL.

Structure Height to Bandwidth Ratio

Example: If a Structure is:		
Greater Than	**But Not More Than**	**Band Width**
10.5 feet (3.2m)	700 feet (214m)	$^1/_7$ of height
701 feet (214m)	900 feet (275m)	$^1/_9$ of height
901 feet (275m)	1,100 feet (336m)	$^1/_{11}$ of height
1,100 feet (336m)	1,300 feet (397m)	$^1/_{13}$ of height

TBL 1

f. ***Structures With a Cover or Roof***. If the structure has a cover or roof, the highest orange band should be continued to cover the entire top of the structure.

g. ***Skeletal Structures Atop Buildings***. If a flagpole, skeletal structure, or similar object is erected on top of a building, the combined height of the object and building will determine whether marking is recommended; however, only the height of the object under study determines the width of the color bands.

h. ***Partial Marking***. If marking is recommended for only a portion of a structure because of shielding by other objects or terrain, the width of the bands should be determined by the overall height of the structure. A minimum of three bands should be displayed on the upper portion of the structure.

i. ***Teardrop Pattern***. Spherical water storage tanks with a single circular standpipe support may be marked in a teardrop-striped pattern. The tank should show alternate stripes of aviation orange and white. The stripes should extend from the top center of the tank to its supporting standpipe. The width of the stripes should be equal, and the width of each stripe at the greatest girth of the tank should not be less than 5 feet (1.5m) nor more than 15 feet (4.6m).

j. ***Community Names***. If it is desirable to paint the name of the community on the side of a tank, the stripe pattern may be broken to serve this purpose. This open area should have a maximum height of 3 feet (0.9m).

k. ***Exceptions.*** Structural designs not conducive to standard markings may be marked as follows:

1. If it is not practical to color the roof of a structure in a checkerboard pattern, it may be colored solid orange.

2. If a spherical structure is not suitable for an exact checkerboard pattern, the shape of the rectangles may be modified to fit the shape of the surface.

3. Storage tanks not suitable for a checkerboard pattern may be colored by alternating bands of aviation orange and white or a limited checkerboard pattern applied to the upper one-third of the structure.

4. The skeletal framework of certain water, gas, and grain storage tanks may be excluded from the checkerboard pattern.

34. MARKERS

Markers are used to highlight structures when it is impractical to make them conspicuous by painting. Markers may also be used in addition to aviation orange and white paint when additional conspicuity is necessary for aviation safety. They should be displayed in conspicuous positions on or adjacent to the structures so as to retain the general definition of the structure. They should be recognizable in clear air from a distance of at least 4,000 feet (1219m) and in all directions from which aircraft are likely to approach. Markers should be distinctively shaped, i.e., spherical or cylindrical, so they are not mistaken for items that are used to convey other information. They should be replaced when faded or otherwise deteriorated.

a. ***Spherical Markers***. Spherical markers are used to identify overhead wires. Markers may be of another shape, i.e., cylindrical, provided the projected area of such markers will not be less than that presented by a spherical marker.

1. ***Size and Color***.

The diameter of the markers used on extensive catenary wires across canyons, lakes, rivers, etc., should be not less than 36 inches (91cm). Smaller 20-inch (51cm) spheres are permitted on less extensive power lines or on power lines below 50 feet (15m) above the ground and within 1,500 feet (458m) of an airport runway end. Each marker should be a solid color such as aviation orange, white, or yellow.

2. ***Installations.***

(a) ***Spacing.*** Markers should be spaced equally along the wire at intervals of approximately 200 feet (61m) or a fraction thereof. Intervals between markers should be less in critical areas near runway ends (i.e., 30 to 50 feet (10m to 15m)). They should be displayed on the highest wire or by another means at the same height as the highest wire. Where there is more than one wire at the highest point, the markers may be installed alternately along each wire if the distance between adjacent markers meets the spacing standard. This method allows the weight and wind loading factors to be distributed.

(b) ***Pattern***. An alternating color scheme provides the most conspicuity against all backgrounds. Mark overhead wires by alternating solid colored markers of aviation orange, white, and yellow. Normally, an orange sphere is placed at each end of a line and the spacing is adjusted (not to exceed 200 feet (61m)) to accommodate the rest of the markers. When less than four markers are used, they should all be aviation orange.

b. ***Flag Markers***. Flags are used to mark certain structures or objects when it is technically impractical to use spherical markers or painting. Some examples are temporary construction equipment, cranes, derricks, oil and other drilling rigs. Catenaries should use spherical markers.

1. ***Minimum Size***. Each side of the flag marker should be at least 2 feet (0.6m) in length.

2. ***Color Patterns***. Flags should be colored as follows:

(a) ***Solid***. Aviation orange.

(b) ***Orange and White***. Arrange two triangular sections, one aviation orange and the other white to form a rectangle.

(c) ***Checkerboard.*** **Flags** 3 feet (0.9m) or larger should be a checkerboard pattern of aviation orange and white squares, each 1 foot (0.3m) plus or minus 10 percent.

3. ***Shape***. Flags should be rectangular in shape and have stiffeners to keep them from drooping in calm wind.

4. ***Display***. Flag markers should be displayed around, on top, or along the highest edge of the obstruction. When flags are used to mark extensive or closely grouped obstructions, they should be displayed approximately 50 feet (15m) apart. The flag stakes should be of such strength and height that they will support the flags above all surrounding ground, structures, and/or objects of natural growth.

35. UNUSUAL COMPLEXITIES

The FAA may also recommend appropriate marking in an area where obstructions are so grouped as to present a common obstruction to air navigation.

36. OMISSION OR ALTERNATIVES TO MARKING

There are two alternatives to marking. Either alternative requires FAA review and concurrence.

a. ***High Intensity Flashing White Lighting Systems***. The high intensity lighting systems are more effective than aviation orange and white paint and therefore can be recommended instead of marking. This is particularly true under certain ambient light conditions involving the position of the sun relative to the direction of flight. When high intensity lighting systems are operated during daytime and twilight, other methods of marking may be omitted. When operated 24 hours a day, other methods of marking and lighting may be omitted.

b. ***Medium Intensity Flashing White Lighting Systems*****.** When medium intensity lighting systems are operated during daytime and twilight on structures 500 feet (153m) AGL or less, other methods of marking may be omitted. When operated 24 hours a day on structures 500 feet (153m) AGL or less, other methods of marking and lighting may be omitted.

Note-
SPONSORS MUST ENSURE THAT ALTERNATIVES TO MARKING ARE COORDINATED WITH THE FCC FOR STRUCTURES UNDER ITS JURISDICTION PRIOR TO MAKING THE CHANGE.

CHAPTER 4. LIGHTING GUIDELINE

40. PURPOSE

This chapter describes the various obstruction lighting systems used to identify structures that an aeronautical study has determined will require added conspicuity. The lighting standards in this circular are the minimum necessary for aviation safety. Recommendations on lighting structures can vary depending on terrain features, weather patterns, geographic location, and in the case of wind turbines, number of structures and overall layout of design.

41. STANDARDS

The standards outlined in this AC are based on the use of light units that meet specified intensities, beam patterns, color, and flash rates as specified in AC 150/5345-43.

These standards may be obtained from:

Department of Transportation
OTS
Subsequent Distribution Office, M-30
Ardmore East Business Center
3341 Q 75th Avenue
Landover, MD 20785

42. LIGHTING SYSTEMS

Obstruction lighting may be displayed on structures as follows:

a. ***Aviation Red Obstruction Lights***. Use flashing beacons and/or steady burning lights during nighttime.

b. ***Medium Intensity Flashing White Obstruction Lights.*** Medium intensity flashing white obstruction lights may be used during daytime and twilight with automatically selected reduced intensity for nighttime operation. When this system is used on structures 500 feet (153m) AGL or less in height, other methods of marking and lighting the structure may be omitted. Aviation orange and white paint is always required for daytime marking on structures exceeding 500 feet (153m) AGL. This system is not normally recommended on structures 200 feet (61m) AGL or less.

c. ***High Intensity Flashing White Obstruction Lights***. Use high intensity flashing white obstruction lights during daytime with automatically selected reduced intensities for twilight and nighttime operations. When this system is used, other methods of marking and lighting the structure may be omitted. This system should not be recommended on structures 500 feet (153m) AGL or less, unless an FAA aeronautical study shows otherwise.

Note-
All flashing lights on a structure should flash simultaneously except for catenary support structures, which have a distinct sequence flashing between levels.

d. ***Dual Lighting***. This system consists of red lights for nighttime and high or medium intensity flashing white lights for daytime and twilight. When a dual lighting system incorporates medium flashing intensity lights on structures 500 feet (153m) or less, or high intensity flashing white lights on structures of any height, other methods of marking the structure may be omitted.

e. ***Obstruction Lights During Construction***. As the height of the structure exceeds each level at which permanent obstruction lights would be recommended, two or more lights of the type specified in the determination should be installed at that level. Temporary high or medium intensity flashing white lights, as recommended in the determination, should be operated 24 hours a day until all permanent lights are in operation. In either case, two or more lights should be installed on the uppermost part of the structure any time it exceeds the height of the temporary construction equipment. They may be turned off for periods when they would interfere with construction personnel. If practical, permanent obstruction lights should be installed and operated at each level as construction progresses. The lights should be positioned to ensure that a pilot has an unobstructed view of at least one light at each level.

f. ***Obstruction Lights in Urban Areas***. When a structure is located in an urban area where there are numerous other white lights (e.g., streetlights, etc.) red obstruction lights with painting or a medium intensity dual system is recommended. Medium intensity lighting is not normally recommended on structures less than 200 feet (61m).

g. ***Temporary Construction Equipment Lighting***. Since there is such a variance in construction cranes, derricks, oil and other drilling rigs, each case should be considered individually. Lights should be installed according to the standards given in Chapters 5, 6, 7, or 8, as they would apply to permanent structures.

43. CATENARY LIGHTING

Lighted markers are available for increased night conspicuity of high-voltage (69KV or greater) transmission line catenary wires. These markers should be used on transmission line catenary wires near airports, heliports, across rivers, canyons, lakes, etc. The lighted markers should be manufacturer certified as recognizable from a minimum distance of 4,000 feet (1219m) under nighttime conditions, minimum visual flight rules (VFR) conditions or having a minimum intensity of at least 32.5 candela. The lighting unit should emit a steady burning red light. They should be used on the highest energized line. If the lighted markers are installed on a line other than the highest catenary, then markers specified in paragraph 34 should be used in addition to the lighted markers. (The maximum distance between the line energizing the lighted markers and the highest catenary above the lighted marker should be no more than 20 feet (6m).) Markers should be distinctively shaped, i.e., spherical, cylindrical, so they are not mistaken for items that are used to convey other information. They should be visible in all directions from which aircraft are likely to approach. The area in the immediate vicinity of the supporting structure's base should be clear of all items and/or objects of natural growth that could interfere with the line-of-sight between a pilot and the structure's lights. Where a catenary wire crossing requires three or more supporting structures, the inner structures should be equipped with enough light units per level to provide a full coverage.

44. INSPECTION, REPAIR AND MAINTENANCE

To ensure the proper candela output for fixtures with incandescent lamps, the voltage provided to the lamp filament should not vary more than plus or minus 3 percent of the rated voltage of the lamp. The input voltage should be measured at the lamp socket with the lamp operating during the hours of normal operation. (For strobes, the input voltage of the power supplies should be within 10 percent of rated voltage.) Lamps should be replaced after being operated for not more than 75 percent of their rated life or immediately upon failure. Flashtubes in a light unit should be replaced immediately upon failure, when the peak effective intensity falls below specification limits or when the fixture begins skipping flashes, or at the manufacturer's recommended intervals. Due to the effects of harsh environments, beacon lenses should be visually inspected for ultraviolet damage, cracks, crazing, dirt build up, etc., to insure that the certified light output has not deteriorated. (See paragraph 23, for reporting requirements in case of failure.)

45. NONSTANDARD LIGHTS

Moored balloons, chimneys, church steeples, and similar obstructions may be floodlighted by fixed search light projectors installed at three or more equidistant points around the base of each obstruction. The searchlight projectors should provide an average illumination of at least 15 foot-candles over the top one-third of the obstruction.

46. PLACEMENT FACTORS

The height of the structure AGL determines the number of light levels. The light levels may be adjusted slightly, but not to exceed 10 feet (3m), when necessary to accommodate guy wires and personnel who replace or repair light fixtures. Except for catenary support structures, the following factors should be considered when determining the placement of obstruction lights on a structure.

a. ***Red Obstruction Lighting Systems***. The overall height of the structure including all appurtenances such as rods, antennas, obstruction lights, etc., determines the number of light levels.

b. ***Medium Intensity Flashing White Obstruction Lighting Systems***. The overall height of the structure including all appurtenances such as rods, antennas, obstruction lights, etc., determines the number of light levels.

c. ***High Intensity Flashing White Obstruction Lighting Systems***. The overall height of the main structure including all appurtenances such as rods, antennas, obstruction lights, etc., determines the number of light levels.

d. ***Dual Obstruction Lighting Systems***. The overall height of the structure including all appurtenances such as rods, antennas, obstruction lights, etc., is used to determine the number of light levels for a medium intensity white obstruction light/red obstruction dual lighting system. The overall height of the structure including all appurtenances is used to determine the number of light levels for a high intensity white obstruction light/red obstruction dual lighting system.

e. ***Adjacent Structures***. The elevation of the tops of adjacent buildings in congested areas may be used as the equivalent of ground level to determine the proper number of light levels required.

f. ***Shielded Lights***. If an adjacent object shields any light, horizontal placement of the lights should be adjusted or additional lights should be mounted on that object to retain or contribute to the definition of the obstruction.

47. MONITORING OBSTRUCTION LIGHTS

Obstruction lighting systems should be closely monitored by visual or automatic means. It is extremely important to visually inspect obstruction lighting in all operating intensities at least once every 24 hours on systems without automatic monitoring. In the event a structure is not readily accessible for visual observation, a properly maintained automatic monitor should be used. This monitor should be designed to register the malfunction of any light on the obstruction regardless of its position or color. When using remote monitoring devices, the communication status and operational status of the system should be confirmed at least once every 24 hours. The monitor (aural or visual) should be located in an area generally occupied by responsible personnel. In some cases, this may require a remote monitor in an attended location. For each structure, a log should be maintained in which daily operations status of the lighting system is recorded. Beacon lenses should be replaced if serious cracks, crazing, dirt build up, etc., has occurred.

48. ICE SHIELDS

Where icing is likely to occur, metal grates or similar protective ice shields should be installed directly over each light unit to prevent falling ice or accumulations from damaging the light units.

49. DISTRACTION

a. Where obstruction lights may distract operators of vessels in the proximity of a navigable waterway, the sponsor must coordinate with the Commandant, U.S. Coast Guard, to avoid interference with marine navigation.

b. The address for marine information and coordination is:

Chief, Aids to Navigation
Division (OPN)
U.S. Coast Guard Headquarters
2100 2nd Street, SW., Rm. 3610
Washington, DC 20593-0001
Telephone: (202) 267-0980

CHAPTER 5. RED OBSTRUCTION LIGHT SYSTEM

50. PURPOSE

Red Obstruction lights are used to increase conspicuity during nighttime. Daytime and twilight marking is required. Recommendations on lighting structures can vary depending on terrain features, weather patterns, geographic location, and in the case of wind turbines, number of structutes and overall layout of design.

51. STANDARDS

The red obstruction lighting system is composed of flashing omnidirectional beacons (L-864) and/or steady burning (L-810) lights. When one or more levels is comprised of flashing beacon lighting, the lights should flash simultaneously.

a. ***Single Obstruction Light***. A single (L-810) light may be used when more than one obstruction light is required either vertically or horizontally or where maintenance can be accomplished within a reasonable time.

1. ***Top Level***. A single light may be used to identify low structures such as airport ILS buildings and long horizontal structures such as perimeter fences and building roof outlines.

2. ***Intermediate Level***. Single lights may be used on skeletal and solid structures when more than one level of lights is installed and there are two or more single lights per level.

b. ***Double Obstruction Light***. A double (L-810) light should be installed when used as a top light, at each end of a row of single obstruction lights, and in areas or locations where the failure of a single unit could cause an obstruction to be totally unlighted.

1. ***Top Level.*** **Structures** 150 feet (46m) AGL or less should have one or more double lights installed at the highest point and operating simultaneously.

2. ***Intermediate Level***. Double lights should be installed at intermediate levels when a malfunction of a single light could create an unsafe condition and in remote areas where maintenance cannot be performed within a reasonable time. Both units may operate simultaneously, or a transfer relay may be used to switch to a spare unit should the active system fail.

3. ***Lowest Level***. The lowest level of light units may be installed at a higher elevation than normal on a structure if the surrounding terrain, trees, or adjacent building(s) would obscure the lights. In certain instances, as determined by an FAA aeronautical study, the lowest level of lights may be eliminated.

52. CONTROL DEVICE

Red obstruction lights should be operated by a satisfactory control device (e.g., photo cell, timer, etc.) adjusted so the lights will be turned on when the northern sky illuminance reaching a vertical surface falls below a level of 60 foot-candles (645.8 lux) but before reaching a level of 35 foot-candles (367.7 lux). The control device should turn the lights off when the northern sky illuminance rises to a level of not more than 60 foot-candles (645.8 lux). The lights may also remain on continuously. The sensing device should, if practical, face the northern sky in the Northern Hemisphere. (See AC 150/5345-43.)

53. POLES, TOWERS, AND SIMILAR SKELETAL STRUCTURES

The following standards apply to radio and television towers, supporting structures for overhead transmission lines, and similar structures.

a. ***Top Mounted Obstruction Light.***

1. ***Structures 150 Feet (46m) AGL or Less***. Two or more steady burning (L-810) lights should be installed in a manner to ensure an unobstructed view of one or more lights by a pilot.

2. ***Structures Exceeding 150 Feet (46m) AGL***. At least one red flashing (L-864) beacon should be installed in a manner to ensure an unobstructed view of one or more lights by a pilot.

3. ***Appurtenances 40 Feet (12m) or Less***. If a rod, antenna, or other appurtenance 40 feet (12m) or less in height is incapable of supporting a red flashing beacon, then it may be placed at the base of the appurtenance. If the mounting location does not allow unobstructed viewing of the beacon by a pilot, then additional beacons should be added.

4. ***Appurtenances Exceeding 40 Feet (12m)***. If a rod, antenna, or other appurtenance exceeding 40 feet (12m) in height is incapable of supporting a red flashing beacon, a supporting mast with one or more beacons should be installed adjacent to the appurtenance. Adjacent installations should not exceed the height of the appurtenance and be within 40 feet (12m) of the tip to allow the pilot an unobstructed view of at least one beacon.

b. ***Mounting Intermediate Levels***. The number of light levels is determined by the height of the structure, including all appurtenances, and is detailed in Appendix 1. The number of lights on each level is determined by the shape and height of the structure. These lights should be mounted so as to ensure an unobstructed view of at least one light by a pilot.

1. ***Steady Burning Lights (L-810).***

(a) ***Structures 350 Feet (107m) AGL or Less***. Two or more steady burning (L-810) lights should be installed on diagonally or diametrically opposite positions.

(b) ***Structures Exceeding 350 Feet (107m) AGL.*** Install steady burning (L-810) lights on each outside corner of each level.

2. ***Flashing Beacons (L-864).***

(a) ***Structures 350 Feet (107m) AGL or Less***. These structures do not require flashing (L-864) beacons at intermediate levels.

(b) ***Structure Exceeding 350 Feet (107m) AGL***. At intermediate levels, two beacons (L-864) should be mounted outside at diagonally opposite positions of intermediate levels.

54. CHIMNEYS, FLARE STACKS, AND SIMILAR SOLID STRUCTURES

a. *Number of Light Units.*

1. The number of units recommended depends on the diameter of the structure at the top. The number of lights recommended below are the minimum.

2. When the structure diameter is:

(a) *20 Feet (6m) or Less.* Three light units per level.

(b) *Exceeding 20 Feet (6m) But Not More Than 100 Feet (31m).* Four light units per level.

(c) *Exceeding 100 Feet (31m) But Not More Than 200 Feet (61m).* Six light units per level.

(d) *Exceeding 200 Feet (61m).* Eight light units per level.

b. ***Top Mounted Obstruction Lights***.

1. *Structures 150 Feet (46m) AGL or Less.* L-810 lights should be installed horizontally at regular intervals at or near the top.

2. *Structures Exceeding 150 Feet (46m) AGL.* At least three L-864 beacons should be installed.

3. *Chimneys, Cooling Towers, and Flare Stacks.* Lights may be displayed as low as 20 feet (6m) below the top to avoid the obscuring effect of deposits and heat generally emitted by this type of structure. It is important that these lights be readily accessible for cleaning and lamp replacement. It is understood that with flare stacks, as well as any other structures associated with the petrol-chemical industry, normal lighting requirements may not be necessary. This could be due to the location of the flare stack/structure within a large well-lighted petrol-chemical plant or the fact that the flare, or working lights surrounding the flare stack/structure, is as conspicuous as obstruction lights.

c. ***Mounting Intermediate Levels***. The number of light levels is determined by the height of the structure including all appurtenances. For cooling towers 600 feet (183m) or less, intermediate light levels are not necessary. Structures exceeding 600 feet (183m) AGL should have a second level of light units installed approximately at the midpoint of the structure and in a vertical line with the top level of lights.

1. ***Steady Burning (L-810) Lights***. The recommended number of light levels may be obtained from Appendix 1. At least three lights should be installed on each level.

2. ***Flashing (L-864) Beacons***. The recommended number of beacon levels may be obtained from Appendix 1. At least three lights should be installed on each level.

(a) *Structures 350 Feet (107m) AGL or Less.* These structures do not need intermediate levels of flashing beacons.

(b) *Structures Exceeding 350 Feet (107m) AGL.* At least three flashing (L-864) beacons should be installed on each level in a manner to allow an unobstructed view of at least one beacon.

55. GROUP OF OBSTRUCTIONS

When individual objects, except wind turbines, within a group of obstructions are not the same height and are spaced a maximum of 150 feet (46m) apart, the prominent objects within the group should be lighted in accordance with the standards for individual obstructions of a corresponding height. If the outer structure is shorter than the prominent, the outer structure should be lighted in accordance with the standards for individual obstructions of a corresponding height. Light units should be placed to ensure that the light is visible to a pilot approaching from **any** direction. In addition, at least one flashing beacon should be installed at the top of a prominent center obstruction or on a special tower located near the center of the group.

56. ALTERNATE METHOD OF DISPLAYING OBSTRUCTION LIGHTS

When recommended in an FAA aeronautical study, lights may be placed on poles equal to the height of the obstruction and installed on or adjacent to the structure instead of installing lights on the obstruction.

57. PROMINENT BUILDINGS, BRIDGES, AND SIMILAR EXTENSIVE OBSTRUCTIONS

When objects within a group of obstructions are approximately the same overall height above the surface and are located a maximum of 150 feet (46m) apart, the group of obstructions may be considered an extensive obstruction. Install light units on the same horizontal plane at the highest portion or edge of prominent obstructions. Light units should be placed to ensure that the light is visible to a pilot approaching from **any** direction. If the structure is a bridge and is over navigable water, the sponsor must obtain prior approval of the lighting installation from the Commander of the District Office of the United States Coast Guard to avoid interference with marine navigation. Steady burning lights should be displayed to indicate the extent of the obstruction as follows:

a. ***Structures 150 Feet (46m) or Less in Any Horizontal Direction***. If the structure/bridge/extensive obstruction is 150 feet (46m) or less horizontally, at least one steady burning light (L-810) should be displayed on the highest point at each end of the major axis of the obstruction. If this is impractical because of the overall shape, display a double obstruction light in the center of the highest point.

b. ***Structures Exceeding 150 Feet (46m) in at Least One Horizontal Direction***. If the structure/bridge/ extensive obstruction exceeds 150 feet (46m) horizontally, display at least one steady burning light for each 150 feet (46m), or fraction thereof, of the overall length of the major axis. At least one of these lights should be displayed on the highest point at each end of the obstruction. Additional lights should be displayed at approximately equal intervals not to exceed 150 feet (46m) on the highest points along the edge between the end lights. If an obstruction is located near a landing area and two or more edges are the same height, the edge nearest the landing area should be lighted.

c. ***Structures Exceeding 150 Feet (46m) AGL***. Steady burning red obstruction lights should be installed on the highest point at each end. At intermediate levels, steady burning red lights should be displayed for each 150 feet (46m) or fraction thereof. The vertical position of these lights should be equidistant between the top lights and the ground level as the shape and type of obstruction will permit. One such light should be displayed at each outside corner on each level with the remaining lights evenly spaced between the corner lights.

d. ***Exceptions***. Flashing red beacons (L-864) may be used instead of steady burning obstruction lights if early or special warning is necessary. These beacons should be displayed on the highest points of an extensive obstruction at intervals not exceeding 3,000 feet (915m). At least three beacons should be displayed on one side of the extensive obstruction to indicate a line of lights.

e. ***Ice Shields***. Where icing is likely to occur, metal grates or similar protective ice shields should be installed directly over each light unit to prevent falling ice or accumulations from damaging the light units. The light should be mounted in a manner to ensure an unobstructed view of at least one light by a pilot approaching from any direction.

CHAPTER 6. MEDIUM INTENSITY FLASHING WHITE OBSTRUCTION LIGHT SYSTEMS

60. PURPOSE

Medium intensity flashing white (L-865) obstruction lights may provide conspicuity both day and night. Recommendations on lighting structures can vary depending on terrain features, weather patterns, geographic location, and in the case of wind turbines, number of structures and overall layout of design.

61. STANDARDS

The medium intensity flashing white light system is normally composed of flashing omnidirectional lights. Medium intensity flashing white obstruction lights may be used during daytime and twilight with automatically selected reduced intensity for nighttime operation. When this system is used on structures 500 feet (153m) AGL or less in height, other methods of marking and lighting the structure may be omitted. Aviation orange and white paint is always required for daytime marking on structures exceeding 500 feet (153m) AGL. This system is not normally recommended on structures 200 feet (61m) AGL or less.

The use of a 24-hour medium intensity flashing white light system in urban/populated areas in not normally recommended due to their tendency to merge with background lighting in these areas at night. This makes it extremely difficult for some types of aviation operations, i.e., med-evac, and police helicopters to see these structures. The use of this type of system in urban and rural areas often results in complaints. In addition, this system is not recommended on structures within 3 nautical miles of an airport.

62. RADIO AND TELEVISION TOWERS AND SIMILAR SKELETAL STRUCTURES

a. ***Mounting Lights***. The number of levels recommended depends on the height of the structure, including antennas and similar appurtenances.

1. ***Top Levels***. One or more lights should be installed at the highest point to provide 360-degree coverage ensuring an unobstructed view.

2. **A*ppurtenances 40 feet (12m) or less***. If a rod, antenna, or other appurtenance 40 feet (12m) or less in height is incapable of supporting the medium intensity flashing white light, then it may be placed at the base of the appurtenance. If the mounting location does not allow unobstructed viewing of the medium intensity flashing white light by a pilot, then additional lights should be added.

3. ***Appurtenances Exceeding 40 feet (12m)***. If a rod, antenna, or other appurtenance exceeds 40 feet (12m) above the tip of the main structure, a medium intensity flashing white light should be placed within 40 feet (12m) from the top of the appurtenance. If the appurtenance (such as a whip antenna) is incapable of supporting the light, one or more lights should be mounted on a pole adjacent to the appurtenance. Adjacent installations should not exceed the height of the appurtenance and be within 40 feet (12m) of the tip to allow the pilot an unobstructed view of at least one light.

b. ***Intermediate Levels***. At intermediate levels, two beacons (L-865) should be mounted outside at diagonally or diametrically opposite positions of intermediate levels. The lowest light level should not be less than 200 feet (61m) AGL.

c. ***Lowest Levels***. The lowest level of light units may be installed at a higher elevation than normal on a structure if the surrounding terrain, trees, or adjacent building(s) would obscure the lights. In certain instances, as determined by an FAA aeronautical study, the lowest level of lights may be eliminated.

d. ***Structures 500 Feet (153m) AGL or Less***. When white lights are used during nighttime and twilight only, marking is required for daytime. When operated 24 hours a day, other methods of marking and lighting are not required.

e. ***Structures Exceeding 500 Feet (153m) AGL***. The lights should be used during nighttime and twilight and may be used 24 hours a day. Marking is always required for daytime.

f. ***Ice Shields***. Where icing is likely to occur, metal grates or similar protective ice shields should be installed directly over each light unit to prevent falling ice or accumulations from damaging the light units. The light should be mounted in a manner to ensure an unobstructed view of at least one light by a pilot approaching from any direction.

63. CONTROL DEVICE

The light intensity is controlled by a device that changes the intensity when the ambient light changes. The system should automatically change intensity steps when the northern sky illumination in the Northern Hemisphere on a vertical surface is as follows:

a. ***Twilight-to-Night***. This should not occur before the illumination drops below five foot-candles (53.8

lux) but should occur before it drops below two foot-candles (21.5 lux).

b. ***Night-to-Day***. The intensity changes listed in subparagraph 63a above should be reversed when changing from the night to day mode.

64. CHIMNEYS, FLARE STACKS, AND SIMILAR SOLID STRUCTURES

a. ***Number of Light Units***. The number of units recommended depends on the diameter of the structure at the top. Normally, the top level is on the highest point of a structure. However, the top level of chimney lights may be installed as low as 20 feet (6m) below the top to minimize deposit build-up due to emissions. The number of lights recommended are the minimum. When the structure diameter is:

1. *20 Feet (6m) or Less.* Three light units per level.

2. *Exceeding 20 Feet (6m) But Not More Than 100 Feet (31m).* Four light units per level.

3. *Exceeding 100 Feet (31m) But Not More Than 200 Feet (61m).* Six light units per level.

4. *Exceeding 200 Feet (61m).* Eight light units per level.

65. GROUP OF OBSTRUCTIONS

When individual objects within a group of obstructions are not the same height and are spaced a maximum of 150 feet (46m) apart, the prominent objects within the group should be lighted in accordance with the standards for individual obstructions of a corresponding height. If the outer structure is shorter than the prominent, the outer structure should be lighted in accordance with the standards for individual obstructions of a corresponding height. Light units should be placed to ensure that the light is visible to a pilot approaching from **any** direction. In addition, at least one medium intensity flashing white light should be installed at the top of a prominent center obstruction or on a special tower located near the center of the group.

66. SPECIAL CASES

Where lighting systems are installed on structures located near highways, waterways, airport approach areas, etc., caution should be exercised to ensure that the lights do not distract or otherwise cause a hazard to motorists, vessel operators, or pilots on an approach to an airport. In these cases, shielding may be necessary. This shielding should not derogate the intended purpose of the lighting system.

67. PROMINENT BUILDINGS AND SIMILAR EXTENSIVE OBSTRUCTIONS

When objects within a group of obstructions are approximately the same overall height above the surface and are located a maximum of 150 feet (46m) apart, the group of obstructions may be considered an extensive obstruction. Install light units on the same horizontal plane at the highest portion or edge of prominent obstructions. Light units should be placed to ensure that the light is visible to a pilot approaching from **any** direction. Lights should be displayed to indicate the extent of the obstruction as follows:

a. ***Structures 150 Feet (46m) or Less in Any Horizontal Direction.*** If the structure/extensive obstruction is 150 feet (46m) or less horizontally, at least one light should be displayed on the highest point at each end of the major axis of the obstruction. If this is impractical because of the overall shape, display a double obstruction light in the center of the highest point.

b. ***Structures Exceeding 150 Feet (46m) in at Least One Horizontal Direction***. If the structure/extensive obstruction exceeds 150 feet (46m) horizontally, display at least one light for each 150 feet (46m) or fraction thereof, of the overall length of the major axis. At least one of these lights should be displayed on the highest point at each end of the obstruction. Additional lights should be displayed at approximately equal intervals not to exceed 150 feet (46m) on the highest points along the edge between the end lights. If an obstruction is located near a landing area and two or more edges are the same height, the edge nearest the landing area should be lighted.

c. ***Structures Exceeding 150 Feet (46m) AGL***. Lights should be installed on the highest point at each end. At intermediate levels, lights should be displayed for each 150 feet (46m), or fraction thereof. The vertical position of these lights should be equidistant between the top lights and the ground level as the shape and type of obstruction will permit. One such light should be displayed at each outside corner on each level with the remaining lights evenly spaced between the corner lights.

CHAPTER 7. HIGH INTENSITY FLASHING WHITE OBSTRUCTION LIGHT SYSTEMS

70. PURPOSE

Lighting with high intensity (L-856) flashing white obstruction lights provides the highest degree of conspicuity both day and night. Recommendations on lighting structures can vary depending on terrain features, weather patterns, geographic location, and in the case of wind turbines, number of structutes and overall layout of design.

71. STANDARDS

Use high intensity flashing white obstruction lights during daytime with automatically selected reduced intensities for twilight and nighttime operations. When high intensity white lights are operated 24 hours a day, other methods of marking and lighting may be omitted. This system should not be recommended on structures 500 feet (153m) AGL or less unless an FAA aeronautical study shows otherwise.

72. CONTROL DEVICE

Light intensity is controlled by a device that changes the intensity when the ambient light changes. The use of a 24-hour high intensity flashing white light system in urban/populated areas is not normally recommended due to their tendency to merge with background lighting in these areas at night. This makes it extremely difficult for some types of aviation operations, i.e., med-evac, and police helicopters to see these structures. The use of this type of system in urban and rural areas often results in complaints.

The system should automatically change intensity steps when the northern sky illumination in the Northern Hemisphere on a vertical surface is as follows:

a. ***Day-to-Twilight***. This should not occur before the illumination drops to 60 foot-candles (645.8 lux), but should occur before it drops below 35 foot-candles (376.7 lux). The illuminance-sensing device should, if practical, face the northern sky in the Northern Hemisphere.

b. ***Twilight-to-Night***. This should not occur before the illumination drops below five foot-candles (53.8 lux), but should occur before it drops below two foot-candles (21.5 lux).

c. ***Night-to-Day***. The intensity changes listed in subparagraph 72 a and b above should be reversed when changing from the night to day mode.

73. UNITS PER LEVEL

One or more light units is needed to obtain the desired horizontal coverage. The number of light units recommended per level (except for the supporting structures of catenary wires and buildings) depends upon the average outside diameter of the specific structure, and the horizontal beam width of the light fixture. The light units should be installed in a manner to ensure an unobstructed view of the system by a pilot approaching from any direction. The number of lights recommended are the minimum. When the structure diameter is:

a. *20 Feet (6m) or Less.* Three light units per level.

b. *Exceeding 20 Feet (6m) But Not More Than 100 Feet (31m).* Four light units per level.

c. *Exceeding 100 Feet (31m).* Six light units per level.

74. INSTALLATION GUIDANCE

Manufacturing specifications provide for the effective peak intensity of the light beam to be adjustable from zero to 8 degrees above the horizon. Normal installation should place the top light at zero degrees to the horizontal and all other light units installed in accordance with Table 2:

Light Unit Elevation Above the Horizontal

Height of Light Unit Above Terrain	Degrees of Elevation Above the Horizontal
Exceeding 500 feet AGL	0
401 feet to 500 feet AGL	1
301 feet to 400 feet AGL	2
300 feet AGL or less	3

TBL 2

a. ***Vertical Aiming***. Where terrain, nearby residential areas, or other situations dictate, the light beam may be further elevated above the horizontal. The main beam of light at the lowest level should not strike the ground closer than 3 statute miles (5km) from the structure. If additional adjustments are necessary, the lights may be individually adjusted upward, in 1-degree increments, starting at the bottom. Excessive elevation may reduce its conspicuity by raising the beam above a collision course flight path.

b. ***Special Cases***. Where lighting systems are installed on structures located near highways, waterways, airport approach areas, etc., caution should be exercised to ensure that the lights do not distract or otherwise cause a hazard to motorists, vessel operators, or pilots on an approach to an airport. In these cases, shielding or an adjustment to the vertical or horizontal light aiming may be necessary. This adjustment should not derogate the intended purpose of the lighting system. Such adjustments may require review action as described in Chapter 1, paragraph 5.

c. ***Relocation or Omission of Light Units***. Light units should not be installed in such a manner that the light pattern/output is disrupted by the structure.

1. ***Lowest Level***. The lowest level of light units may be installed at a higher elevation than normal on a structure if the surrounding terrain, trees, or adjacent building(s) would obscure the lights. In certain instances, as determined by an FAA aeronautical study, the lowest level of lights may be eliminated.

2. ***Two Adjacent Structures***. Where two structures are situated within 500 feet (153m) of each other and the light units are installed at the same levels, the sides of the structures facing each other need not be lighted. However, all lights on both structures must flash simultaneously, except for adjacent catenary support structures. Adjust vertical placement of the lights to either or both structures' intermediate levels to place the lights on the same horizontal plane. Where one structure is higher than the other, complete level(s) of lights should be installed on that part of the higher structure that extends above the top of the lower structure. If the structures are of such heights that the levels of lights cannot be placed in identical horizontal planes, then the light units should be placed such that the center of the horizontal beam patterns do not face toward the adjacent structure. For example, structures situated north and south of each other should have the light units on both structures installed on a northwest/southeast and northeast/southwest orientation.

3. ***Three or More Adjacent Structures***. The treatment of a cluster of structures as an individual or a complex of structures will be determined by the FAA as the result of an aeronautical study, taking into consideration the location, heights, and spacing with other structures.

75. ANTENNA OR SIMILAR APPURTENANCE LIGHT

When a structure lighted by a high intensity flashing light system is topped with an antenna or similar appurtenance exceeding 40 feet (12m) in height, a medium intensity flashing white light (L-865) should be placed within 40 feet (12m) from the tip of the appurtenance. This light should operate 24 hours a day and flash simultaneously with the rest of the lighting system.

76. CHIMNEYS, FLARE STACKS, AND SIMILAR SOLID STRUCTURES

The number of light levels depends on the height of the structure excluding appurtenances. Three or more lights should be installed on each level in such a manner to ensure an unobstructed view by the pilot. Normally, the top level is on the highest point of a structure. However, the top level of chimney lights may be installed as low as 20 feet (6m) below the top to minimize deposit build-up due to emissions.

77. RADIO AND TELEVISION TOWERS AND SIMILAR SKELETAL STRUCTURES

a. ***Mounting Lights***. The number of levels recommended depends on the height of the structure, including antennas and similar appurtenances. At least three lights should be installed on each level and mounted to ensure that the effective intensity of the full horizontal beam coverage is not impaired by the structural members.

b. ***Top Level***. One level of lights should be installed at the highest point of the structure. If the highest point is a rod or antenna incapable of supporting a lighting system, then the top level of lights should be installed at the highest portion of the main skeletal structure. When guy wires come together at the top, it may be necessary to install this level of lights as low as 10 feet (3m) below the top. If the rod or antenna exceeds 40 feet (12m) above the main structure, a medium intensity flashing white light (L-865) should be mounted on the highest point. If the appurtenance (such as a whip antenna) is incapable of supporting a medium intensity light, one or more lights should be installed on a pole adjacent to the appurtenance. Adjacent installation should not exceed the height of the appurtenance and be within 40 feet (12m) of the top to allow an unobstructed view of at least one light.

c. ***Ice Shields***. Where icing is likely to occur, metal grates or similar protective ice shields should be installed directly over each light unit to prevent falling ice or accumulations from damaging the light units.

78. HYPERBOLIC COOLING TOWERS

Light units should be installed in a manner to ensure an unobstructed view of at least two lights by a pilot approaching from **any** direction.

a. ***Number of Light Units***. The number of units recommended depends on the diameter of the structure at the top. The number of lights recommended in the following table are the minimum. When the structure diameter is:

1. *20 Feet (6m) or Less.* Three light units per level.

2. *Exceeding 20 Feet (6m) But Not More Than 100 Feet (31m).* Four light units per level.

3. *Exceeding 100 Feet (31m) But Not More Than 200 Feet (61m).* Six light units per level.

4. *Exceeding 200 Feet (61m).* Eight light units per level.

b. ***Structures Exceeding 600 Feet (183m) AGL***. Structures exceeding 600 feet (183m) AGL should have a second level of light units installed approximately at the midpoint of the structure and in a vertical line with the top level of lights.

79. PROMINENT BUILDINGS AND SIMILAR EXTENSIVE OBSTRUCTIONS

When objects within a group of obstructions are approximately the same overall height above the surface and are located not more than 150 feet (46m) apart, the group of obstructions may be considered an extensive obstruction. Install light units on the same horizontal plane at the highest portion or edge of prominent obstructions. Light units should be placed to ensure that the light is visible to a pilot approaching from **any** direction. These lights may require shielding, such as louvers, to ensure minimum adverse impact on local communities. Extreme caution in the use of high intensity flashing white lights should be exercised.

a. ***If the Obstruction is 200 feet (61m) or Less in Either Horizontal*** *Dimension,* install three or more light units at the highest portion of the structure in a manner to ensure that at least one light is visible to a pilot approaching from **any** direction. Units may be mounted on a single pedestal at or near the center of the obstruction. If light units are placed more than 10 feet (3m) from the center point of the structure, use a minimum of four units.

b. ***If the Obstruction Exceeds 200 Feet (61m) in One Horizontal Dimension***, but is 200 feet (61m) or less in the other, two light units should be placed on each of the shorter sides. These light units may either be installed adjacent to each other at the midpoint of the edge of the obstruction or at (near) each corner with the light unit aimed to provide 180 degrees of coverage at each edge. One or more light units should be installed along the overall length of the major axis. These lights should be installed at approximately equal intervals not to exceed a distance of 100 feet (31m) from the corners or from each other.

c. ***If the Obstruction Exceeds 200 Feet (61m) in Both Horizontal Dimensions***, light units should be equally spaced along the overall perimeter of the obstruction at intervals of 100 feet (31m) or fraction thereof.

CHAPTER 8. DUAL LIGHTING WITH RED/MEDIUM INTENSITY FLASHING WHITE SYSTEMS

80. PURPOSE

This dual lighting system includes red lights (L-864) for nighttime and medium intensity flashing white lights (L-865) for daytime and twilight use. This lighting system may be used in lieu of operating a medium intensity flashing white lighting system at night. There may be some populated areas where the use of medium intensity at night may cause significant environmental concerns. The use of the dual lighting system should reduce/mitigate those concerns. Recommendations on lighting structures can vary depending on terrain features, weather patterns, geographic location, and in the case of wind turbines, number of structutes and overall layout of design.

81. INSTALLATION

The light units should be installed as specified in the appropriate portions of Chapters 4, 5, and 6. The number of light levels needed may be obtained from Appendix 1.

82. OPERATION

Lighting systems should be operated as specified in Chapter 3. Both systems should not be operated at the same time; however, there should be no more than a 2-second delay when changing from one system to the other. Outage of one of two lamps in the uppermost red beacon (L-864 incandescent unit) or outage of any uppermost red light shall cause the white obstruction light system to operate in its specified ”night” step intensity.

83. CONTROL DEVICE

The light system is controlled by a device that changes the system when the ambient light changes. The system should automatically change steps when

the northern sky illumination in the Northern Hemisphere on a vertical surface is as follows:

a. ***Twilight-to-Night***. This should not occur before the illumination drops below 5 foot-candles (53.8 lux) but should occur before it drops below 2 foot-candles (21.5 lux).

b. ***Night-to-Day***. The intensity changes listed in subparagraph 83 a above should be reversed when changing from the night to day mode.

84. ANTENNA OR SIMILAR APPURTENANCE LIGHT

When a structure utilizing this dual lighting system is topped with an antenna or similar appurtenance exceeding 40 feet (12m) in height, a medium intensity flashing white (L-865) and a red flashing beacon (L-864) should be placed within 40 feet (12m) from the tip of the appurtenance. The white light should operate during daytime and twilight and the red light during nighttime. These lights should flash simultaneously with the rest of the lighting system.

85. OMISSION OF MARKING

When medium intensity white lights are operated on structures 500 feet (153m) AGL or less during daytime and twilight, other methods of marking may be omitted.

CHAPTER 9. DUAL LIGHTING WITH RED/HIGH INTENSITY FLASHING WHITE SYSTEMS

90. PURPOSE

This dual lighting system includes red lights (L-864) for nighttime and high intensity flashing white lights (L-856) for daytime and twilight use. This lighting system may be used in lieu of operating a flashing white lighting system at night. There may be some populated areas where the use of high intensity lights at night may cause significant environmental concerns and complaints. The use of the dual lighting system should reduce/mitigate those concerns. Recommendations on lighting structures can vary depending on terrain features, weather patterns, geographic location, and in the case of wind turbines, number of structutes and overall layout of design.

91. INSTALLATION

The light units should be installed as specified in the appropriate portions of Chapters 4, 5, and 7. The number of light levels needed may be obtained from Appendix 1.

92. OPERATION

Lighting systems should be operated as specified in Chapters 4, 5, and 7. Both systems should not be operated at the same time; however, there should be no more than a 2-second delay when changing from one system to the other. Outage of one of two lamps in the uppermost red beacon (L-864 incandescent unit) or outage of any uppermost red light shall cause the white obstruction light system to operate in its specified "night" step intensity.

93. CONTROL DEVICE

The light intensity is controlled by a device that changes the intensity when the ambient light changes. The system should automatically change intensity steps when the northern sky illumination in the Northern Hemisphere on a vertical surface is as follows:

a. ***Day-to-Twilight***. This should not occur before the illumination drops to 60 foot-candles (645.8 lux) but should occur before it drops below 35 foot-candles (376.7 lux). The illuminance-sensing device should, if practical, face the northern sky in the Northern Hemisphere.

b. ***Twilight-to-Night***. This should not occur before the illumination drops below 5 foot-candles (53.8 lux) but should occur before it drops below 2 foot-candles (21.5 lux).

c. ***Night-to-Day***. The intensity changes listed in subparagraph 93 a and b above should be reversed when changing from the night to day mode.

94. ANTENNA OR SIMILAR APPURTENANCE LIGHT

When a structure utilizing this dual lighting system is topped with an antenna or similar appurtenance exceeding 40 feet (12m) in height, a medium intensity flashing white light (L-865) and a red flashing beacon (L-864) should be placed within 40 feet (12m) from the tip of the appurtenance. The white light should operate during daytime and twilight and the red light during nighttime.

95. OMISSION OF MARKING

When high intensity white lights are operated during daytime and twilight, other methods of marking may be omitted.

CHAPTER 10. MARKING AND LIGHTING OF CATENARY AND CATENARY SUPPORT STRUCTURES

100. PURPOSE

This chapter provides guidelines for marking and lighting catenary and catenary support structures. The recommended marking and lighting of these structures is intended to provide day and night conspicuity and to assist pilots in identifying and avoiding catenary wires and associated support structures.

101. CATENARY MARKING STANDARDS

Lighted markers are available for increased night conspicuity of high-voltage (69KV or greater) transmission line catenary wires. These markers should be used on transmission line catenary wires near airports, heliports, across rivers, canyons, lakes, etc. The lighted markers should be manufacturer certified as recognizable from a minimum distance of 4,000 feet (1219m) under nighttime conditions, minimum VFR conditions or having a minimum intensity of at least 32.5 candela. The lighting unit should emit a steady burning red light. They should be used on the highest energized line. If the lighted markers are installed on a line other than the highest catenary, then markers specified in paragraph 34 should be used in addition to the lighted markers. (The maximum distance between the line energizing the lighted markers and the highest catenary above the lighted marker should be no more than 20 feet (6m).) Markers should be distinctively shaped, i.e., spherical, cylindrical, so they are not mistaken for items that are used to convey other information. They should be visible in all directions from which aircraft are likely to approach. The area in the immediate vicinity of the supporting structure's base should be clear of all items and/or objects of natural growth that could interfere with the line-of-sight between a pilot and the structure's lights. Where a catenary wire crossing requires three or more supporting structures, the inner structures should be equipped with enough light units per level to provide a full coverage.

a. ***Size and Color***. The diameter of the markers used on extensive catenary wires across canyons, lakes, rivers, etc., should be not less than 36 inches (91cm). Smaller 20-inch (51cm) markers are permitted on less extensive power lines or on power lines below 50 feet (15m) above the ground and within 1,500 feet (458m) of an airport runway end. Each marker should be a solid color such as aviation orange, white, or yellow.

b. ***Installation.***

1. ***Spacing.*** Lighted markers should be spaced equally along the wire at intervals of approximately 200 feet (61m) or a fraction thereof. Intervals between markers should be less in critical areas near runway ends, i.e., 30 to 50 feet (10m to 15m). If the markers are installed on a line other than the highest catenary, then markers specified in paragraph 34 should be used in addition to the lighted markers. The maximum distance between the line energizing the lighted markers and the highest catenary above the markers can be no more than 20 feet (6m). The lighted markers may be installed alternately along each wire if the distance between adjacent markers meets the spacing standard. This method allows the weight and wind loading factors to be distributed.

2. ***Pattern***. An alternating color scheme provides the most conspicuity against all backgrounds. Mark overhead wires by alternating solid colored markers of aviation orange, white, and yellow. Normally, an orange marker is placed at each end of a line and the spacing is adjusted (not to exceed 200 feet (61m)) to accommodate the rest of the markers. When less than four markers are used, they should all be aviation orange.

102. CATENARY LIGHTING STANDARDS

When using medium intensity flashing white (L-866), high intensity flashing white (L-857), dual medium intensity (L-866/L-885) or dual high intensity (L-857/885) lighting systems, operated 24 hours a day, other marking of the support structure is not necessary.

a. ***Levels***. A system of three levels of sequentially flashing light units should be installed on each supporting structure or adjacent terrain. Install one level at the top of the structure, one at the height of the lowest point in the catenary and one level approximately midway between the other two light levels. The middle level should normally be at least 50 feet (15m) from the other two levels. The middle light unit may be deleted when the distance between the top and the bottom light levels is less than 100 feet (30m).

1. ***Top Levels***. One or more lights should be installed at the top of the structure to provide 360-degree coverage ensuring an unobstructed view. If the installation presents a potential danger to maintenance personnel, or when necessary for lightning protection, the top level of lights may be mounted as low as 20 feet (6m) below the highest point of the structure.

2. ***Horizontal Coverage***. The light units at the middle level and bottom level should be installed so as to provide a minimum of 180-degree coverage centered perpendicular to the flyway. Where a catenary crossing is situated near a bend in a river, canyon, etc., or is not perpendicular to the flyway, the horizontal beam should be directed to provide the most effective light coverage to warn pilots approaching from either direction of the catenary wires.

3. ***Variation.*** The vertical and horizontal arrangements of the lights may be subject to the structural limits of the towers and/or adjacent terrain. A tolerance of 20 percent from uniform spacing of the bottom and middle light is allowed. If the base of the supporting structure(s) is higher than the lowest point in the catenary, such as a canyon crossing, one or more lights should be installed on the adjacent terrain at the level of the lowest point in the span. These lights should be installed on the structure or terrain at the height of the lowest point in the catenary.

b. ***Flash Sequence***. The flash sequence should be middle, top, and bottom with all lights on the same level flashing simultaneously. The time delay between flashes of levels is designed to present a unique system display. The time delay between the start of each level of flash duration is outlined in FAA AC 150/5345-43, Specification for Obstruction Lighting Equipment.

c. ***Synchronization***. Although desirable, the corresponding light levels on associated supporting towers of a catenary crossing need not flash simultaneously.

d. ***Structures 500 feet (153m) AGL or Less***. When medium intensity white lights (L-866) are operated 24 hours a day, or when a dual red/medium intensity system (L-866 daytime & twilight/L-885 nighttime) is used, marking can be omitted. When using a medium intensity while light (L-866) or a flashing red light (L-885) during twilight or nighttime only, painting should be used for daytime marking.

e. *Structures Exceeding 500 Feet (153m) AGL*. When high intensity white lights (L-857) are operated 24 hours a day, or when a dual red/high intensity system (L-857 daytime and twilight/L-885 nighttime) is used, marking can be omitted. This system should not be recommended on structures 500 feet (153m) or less unless an FAA aeronautical study shows otherwise. When a flashing red obstruction light (L-885), a medium intensity (L-866) flashing white lighting system or a high intensity white lighting system (L-857) is used for nighttime and twilight only, painting should be used for daytime marking.

103. CONTROL DEVICE

The light intensity is controlled by a device (photocell) that changes the intensity when the ambient light changes. The lighting system should automatically change intensity steps when the northern sky illumination in the Northern Hemisphere on a vertical surface is as follows:

a. ***Day-to-Twilight (L-857 System)***. This should not occur before the illumination drops to 60 foot-candles (645.8 lux), but should occur before it drops below 35 foot-candles (376.7 lux). The illuminant-sensing device should, if practical, face the northern sky in the Northern Hemisphere.

b. ***Twilight-to-Night (L-857 System).*** This should not occur before the illumination drops below 5 foot-candles (53.8 lux), but should occur before it drops below 2 foot-candles (21.5 lux).

c. ***Night-to-Day***. The intensity changes listed in subparagraph 103 a. and b. above should be reversed when changing from the night to day mode.

d. ***Day-to-Night (L-866 or L-885/L-866).*** This should not occur before the illumination drops below 5 foot-candles (563.8 lux) but should occur before it drops below 2 foot-candles (21.5 lux).

e. ***Night-to-Day***. The intensity changes listed in subparagraph d. above should be reversed when changing from the night to day mode.

f. ***Red Obstruction (L-885).*** The red lights should not turn on until the illumination drops below 60 foot-candles (645.8 lux) but should occur before reaching a level of 35 foot-candles (367.7 lux). Lights should not turn off before the illuminance rises above 35 foot-candles (367.7 lux), but should occur before reaching 60 foot-candles (645.8 lux).

104. AREA SURROUNDING CATENARY SUPPORT STRUCTURES

The area in the immediate vicinity of the supporting structure’s base should be clear of all items and/or objects of natural growth that could interfere with the line-of-sight between a pilot and the structure’s lights.

105. THREE OR MORE CATENARY SUPPORT STRUCTURES

Where a catenary wire crossing requires three or more supporting structures, the inner structures should be equipped with enough light units per level to provide a full 360-degree coverage.

CHAPTER 11. MARKING AND LIGHTING MOORED BALLOONS AND KITES

110. PURPOSE

The purpose of marking and lighting moored balloons, kites, and their cables or mooring lines is to indicate the presence and general definition of these objects to pilots when converging from any normal angle of approach.

111. STANDARDS

These marking and lighting standards pertain to all moored balloons and kites that require marking and lighting under 14 CFR, part 101.

112. MARKING

Flag markers should be used on mooring lines to warn pilots of their presence during daylight hours.

a. ***Display.*** Markers should be displayed at no more than 50-foot (15m) intervals and should be visible for at least 1 statute mile.

b. ***Shape.*** Markers should be rectangular in shape and not less than 2 feet (0.6m) on a side. Stiffeners should be used in the borders so as to expose a large area, prevent drooping in calm wind, or wrapping around the cable.

c. ***Color Patterns***. One of the following color patterns should be used:

1. ***Solid Color***. Aviation orange.

2. ***Orange and White.*** Two triangular sections, one of aviation orange and the other white, combined to form a rectangle.

113. PURPOSE

Flashing obstruction lights should be used on moored balloons or kites and their mooring lines to warn pilots of their presence during the hours between sunset and sunrise and during periods of reduced visibility. These lights may be operated 24 hours a day.

a. ***Systems***. Flashing red (L-864) or white beacons (L-865) may be used to light moored balloons or kites. High intensity lights (L-856) are not recommended.

b. ***Display***. Flashing lights should be displayed on the top, nose section, tail section, and on the tether cable approximately 15 feet (4.6m) below the craft so as to define the extremes of size and shape. Additional lights should be equally spaced along the cable’s overall length for each 350 feet (107m) or fraction thereof.

c. ***Exceptions.*** When the requirements of this paragraph cannot be met, floodlighting may be used.

114. OPERATIONAL CHARACTERISTICS

The light intensity is controlled by a device that changes the intensity when the ambient light changes. The system should automatically turn the lights on and change intensities as ambient light condition change. The reverse order should apply in changing from nighttime to daytime operation. The lights should flash simultaneously.

CHAPTER 12. MARKING AND LIGHTING EQUIPMENT AND INFORMATION

120. PURPOSE

This chapter lists documents relating to obstruction marking and lighting systems and where they may be obtained.

121. PAINT STANDARD

Paint and aviation colors/gloss, referred to in this publication should conform to Federal Standard FED-STD-595. Approved colors shall be formulated without the use of Lead, Zinc Chromate or other heavy metals to match International Orange, White and Yellow. All coatings shall be manufactured and labeled to meet Federal Environmental Protection Act Volatile Organic Compound(s) guidelines, including the National Volatile Organic Compound Emission Standards for architectural coatings.

a. **Exterior Acrylic Waterborne Paint.** Coating should be a ready mixed, 100% acrylic, exterior latex formulated for application directly to galvanized surfaces. Ferrous iron and steel or non-galvanized surfaces shall be primed with a manufacturer recommended primer compatible with the finish coat.

b. **Exterior Solventborne Alkyd Based Paint**. Coating should be ready mixed, alkyd-based, exterior enamel for application directly to non-galvanized surfaces such as ferrous iron and steel. Galvanized surfaces shall be primed with a manufacturer primer compatible with the finish coat.

Paint Standards Color Table

COLOR	NUMBER
Orange	12197
White	17875
Yellow	13538

TBL 3

Note-
1. Federal specification T1-P-59, aviation surface paint, ready mixed international orange.

2. Federal specification T1-102, aviation surface paint, oil titanium zinc.

3. Federal specification T1-102, aviation surface paint, oil, exterior, ready mixed, white and light tints.

122. AVAILABILITY OF SPECIFICATIONS

Federal specifications describing the technical characteristics of various paints and their application techniques may be obtained from:

GSA- Specification Branch
470 L'Enfant Plaza
Suite 8214
Washington, DC 20407
Telephone: (202) 619-8925

123. LIGHTS AND ASSOCIATED EQUIPMENT

The lighting equipment referred to in this publication should conform to the latest edition of one of the following specifications, as applicable:

a. ***Obstruction Lighting Equipment***.

1. AC 150/5345-43, FAA Specification for Obstruction Lighting Equipment.

2. Military Specifications MIL-L-6273, Light, Navigational, Beacon, Obstacle or Code, Type G-1.

3. Military Specifications MIL-L-7830, Light Assembly, Markers, Aircraft Obstruction.

b. ***Certified Equipment***.

1. AC 150/5345-53, Airport Lighting Certification Program, lists the manufacturers that have demonstrated compliance with the specification requirements of AC 150/5345-43.

2. Other manufacturers' equipment may be used provided that equipment meets the specification requirements of AC 150/5345-43.

c. ***Airport Lighting Installation and Maintenance***.

1. AC 150/5340-21, Airport Miscellaneous Lighting Visual Aids, provides guidance for the installation, maintenance, testing, and inspection of obstruction lighting for airport visual aids such as airport beacons, wind cones, etc.

2. AC 150/5340-26, Maintenance of Airport Visual Aid Facilities, provides guidance on the maintenance of airport visual aid facilities.

d. ***Vehicles.***

1. AC 150/5210-5, Painting, Marking, and Lighting of Vehicles Used on an Airport, contains provisions for marking vehicles principally used on airports.

2. FAA Facilities**.** Obstruction marking for FAA facilities shall conform to FAA Drawing Number D-5480, referenced in FAA Standard FAA-STD-003, Paint Systems for Structures.

124. AVAILABILITY

The standards and specifications listed above may be obtained free of charge from the below-indicated office:

a. ***Military Specifications:***

Standardization Document Order Desk 700 Robbins Avenue Building #4, Section D Philadelphia, PA 19111-5094

b. *FAA Specifications:*

Manager, ASD-110 Department of Transportation Document Control Center Martin Marietta/Air Traffic Systems 475 School St., SW. Washington, DC 20024 Telephone: (202) 646-2047 FAA Contractors Only

c. *FAA Advisory Circulars:*

Department of Transportation TASC Subsequent Distribution Office, SVC-121.23 Ardmore East Business Center 3341 Q 75th Avenue Landover, MD 20785 Telephone: (301) 322-4961

CHAPTER 13. MARKING AND LIGHTING WIND TURBINE FARMS

130. PURPOSE

This chapter provides guidelines for the marking and lighting of wind turbine farms. For the purposes of this advisory circular, wind turbine farms are defined as a wind turbine development that contains more than three (3) turbines of heights over 200 feet above ground level. The recommended marking and lighting of these structures is intended to provide day and night conspicuity and to assist pilots in identifying and avoiding these obstacles.

131. GENERAL STANDARDS

The development of wind turbine farms is a very dynamic process, which constantly changes based on the differing terrain they are built on. Each wind turbine farm is unique; therefore it is important to work closely with the sponsor to determine a lighting scheme that provides for the safety of air traffic. The following are guidelines that are recommended for wind turbine farms. Consider the proximity to airports and VFR routes, extreme terrain where heights may widely vary, and local flight activity when making the recommendation.

a. Not all wind turbine units within an installation or farm need to be lighted. Definition of the periphery of the installation is essential; however, lighting of interior wind turbines is of lesser importance unless they are taller than the peripheral units.

b. Obstruction lights within a group of wind turbines should have unlighted separations or gaps of no more than ½ statute mile if the integrity of the group appearance is to be maintained. This is especially critical if the arrangement of objects is essentially linear.

c. Any array of flashing or pulsed obstruction lighting should be synchronized or flash simultaneously.

d. Nighttime wind turbine obstruction lighting should consist of the preferred FAA L-864 aviation red-colored flashing lights.

e. White strobe fixtures (FAA L-865) may be used in lieu of the preferred L-864 red flashing lights, but must be used alone without any red lights, and must be positioned in the same manner as the red flashing lights.

f. The white paint most often found on wind turbine units is the most effective daytime early warning device. Other colors, such as light gray or blue, appear to be significantly less effective in providing daytime warning. Daytime lighting of wind turbine farms is not required, as long as the turbine structures are painted in a bright white color or light off-white color most often found on wind turbines.

132. WIND TURBINE CONFIGURATIONS –

Prior to recommending marking and lighting, determine the configuration and the terrain of the wind turbine farm. The following is a description of the most common configurations.

a. Linear – wind turbine farms in a line-like arrangement, often located along a ridge line, the face of a mountain or along borders of a mesa or field. The line may be ragged in shape or be periodically broke, and may vary in size from just a few turbines up to 20 miles long.

b. Cluster – turbine farms where the turbines are placed in circles like groups on top of a mesa, or within a large field. A cluster is typically characterized by having a pronounced perimeter, with various turbines placed inside the circle at various, erratic distances throughout the center of the circle.

c. Grid – turbine farms arranged in a geographical shape such as a square or a rectangle, where each turbine is set a consistent distance from each other in rows, giving the appearance that they are part of a square like pattern.

133. MARKING STANDARDS

The bright white or light off-white paint most often found on wind turbines has been shown to be most effective, and if used, no lights are required during the daytime. However, if darker paint is used, wind turbine marking should be supplemented with daytime lighting, as required.

134. LIGHTING STANDARDS

a. Flashing red (L864), or white (L-865) lights may be used to light wind turbines. Studies have shown that red lights are most effective, and should be the first consideration for lighting recommendations of wind turbines.

b. Obstruction lights should have unlighted separations or gaps of no more than ½ mile. Lights should flash simultaneously. Should the synchronization of the lighting system fail, a lighting outage report should be made in accordance with paragraph 23 of this advisory circular. Light fixtures should be placed as high as possible on the turbine nacelle, so as to be visible from 360 degrees.

c. Linear Turbine Configuration. Place a light on each turbine positioned at each end of the line or string of turbines. Lights should be no more than ½ statute mile, or 2640 feet from the last lit turbine. In the event the last segment is significantly short, push the lit turbines back towards the starting point to present a well balanced string of lights. High concentrations of lights should be avoided.

d. Cluster Turbine Configuration. Select a starting point among the outer perimeter of the cluster. This turbine should be lit, and a light should be placed on the next turbine so that no more than a ½ statute mile gap exists. Continue this pattern around the perimeter. If the distance across the cluster is greater than 1 mile, and/or the terrain varies by more than 100 feet, place one or more lit turbines at locations throughout the center of the cluster.

e. Grid Turbine Configuration. Select each of the defined corners of the layout to be lit, and then utilize the same concept of the cluster configuration as outlined in paragraph d.

f. Special Considerations. On occasion, one or two turbines may be located apart from the main grouping of turbines. If one or two turbines protrude from the general limits of the turbine farm, these turbines should be lit.

APPENDIX 1: Specifications for Obstruction Lighting Equipment Classification

APPENDIX

Type	Description
L-810	Steady-burning Red Obstruction Light
L-856	High Intensity Flashing White Obstruction Light (40 FPM)
L-857	High Intensity Flashing White Obstruction Light (60 FPM)
L-864	Flashing Red Obstruction Light (20-40 FPM)
L-865	Medium Intensity Flashing White Obstruction Light (40-FPM)
L-866	Medium Intensity Flashing White Obstruction Light (60-FPM)
L-864/L-865	Dual: Flashing Red Obstruction Light (20-40 FPM) and Medium Intensity Flashing White Obstruction Light (40 FPM)
L-885	Red Catenary 60 FPM
FPM = Flashes Per Minute	

TBL 4

PAINTING AND/OR DUAL LIGHTING OF CHIMNEYS, POLES, TOWERS, AND SIMILAR STRUCTURES

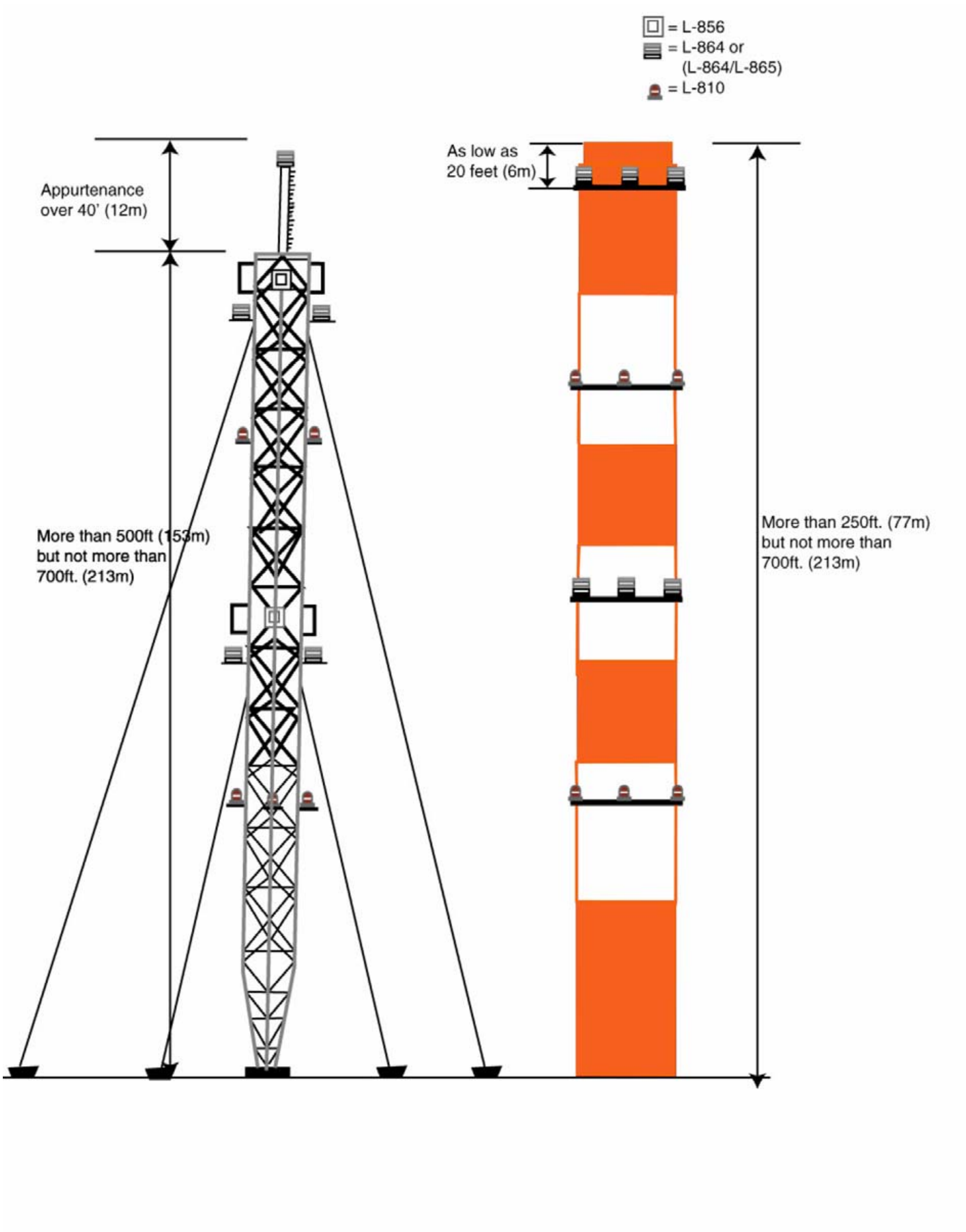
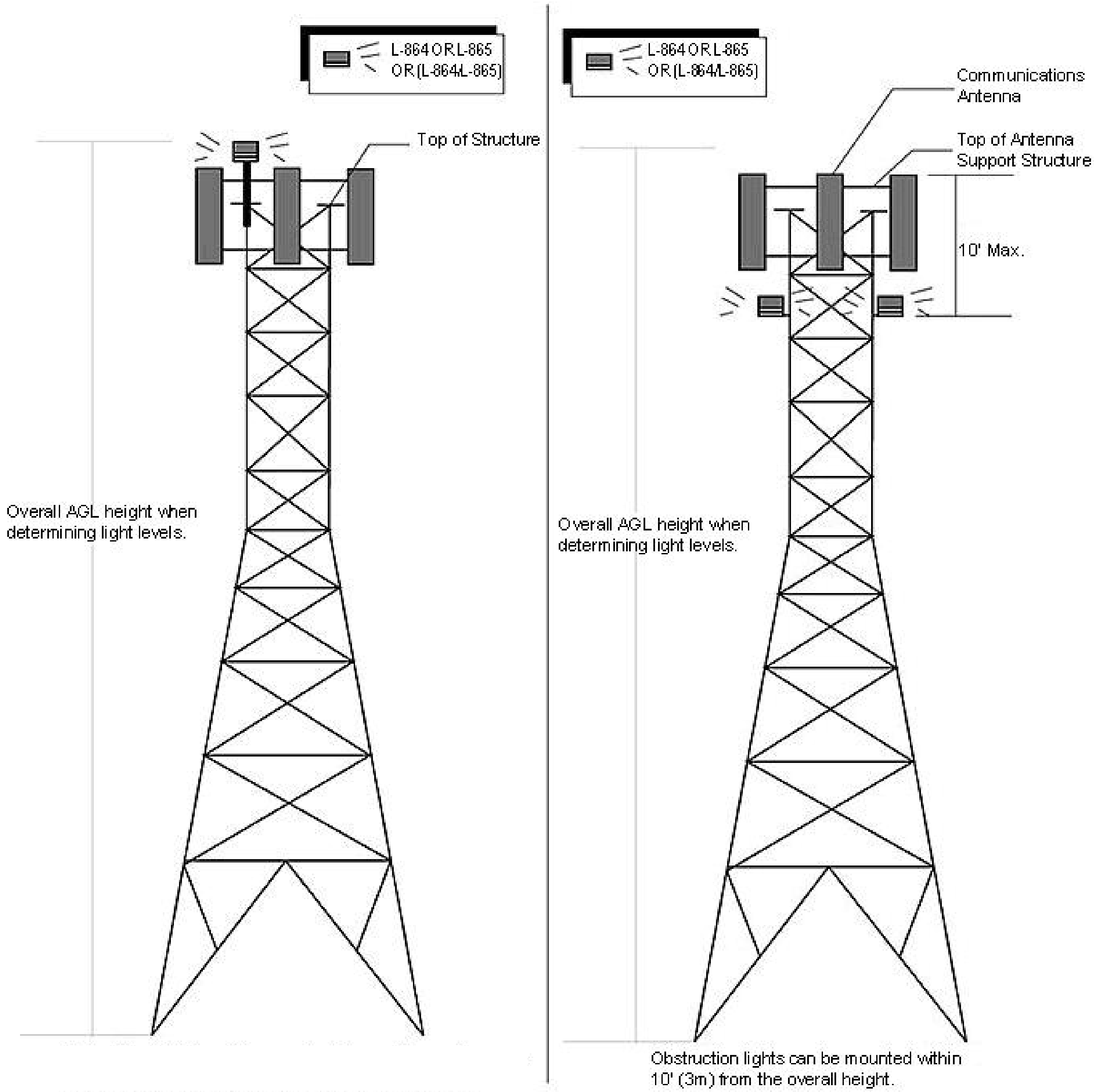


FIG 1



Intermediate lighting not shown. Overall AGL height if more than 200' (61m), but not more than 500' (153m).

FIG 2

PAINTING AND LIGHTING OF WATER TOWERS, STORAGE TANKS, AND SIMILAR STRUCTURES

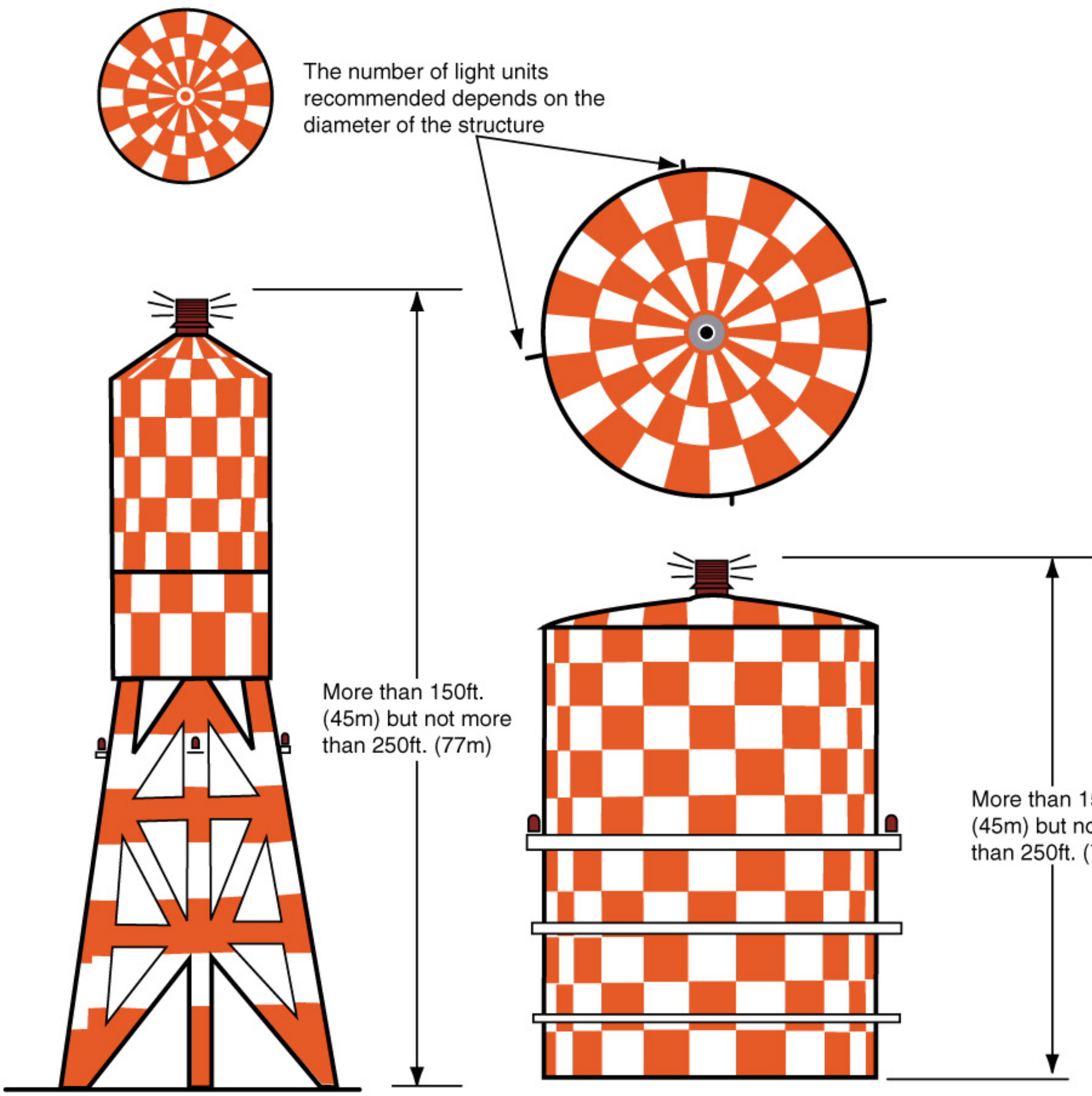


FIG 3

PAINTING AND LIGHTING OF WATER TOWERS ANDE SIMILAR STRUCTURES

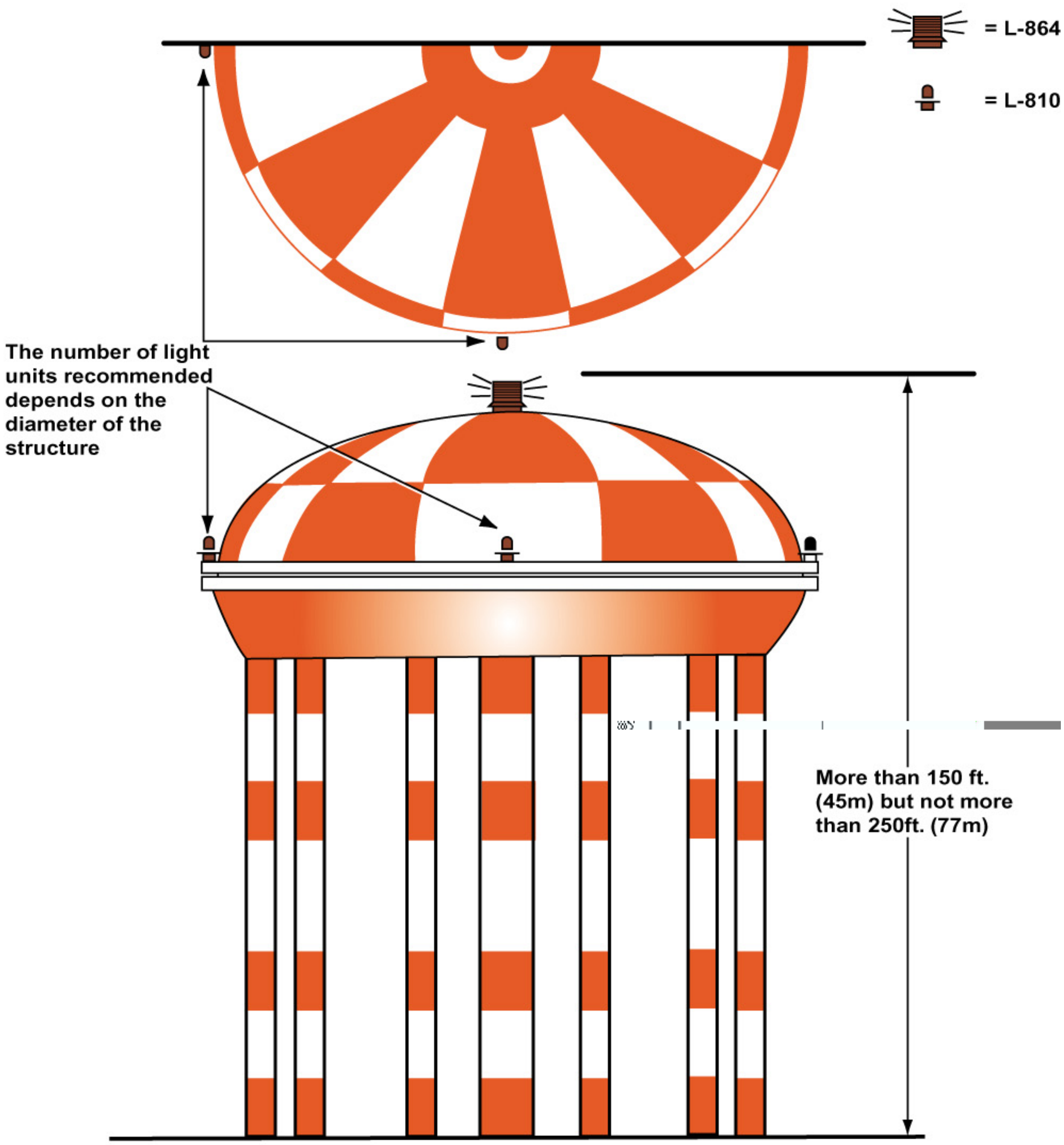


FIG 4

PAINTING OF SINGLE PEDESTAL WATER TOWER BY TEARDROP PATTERN

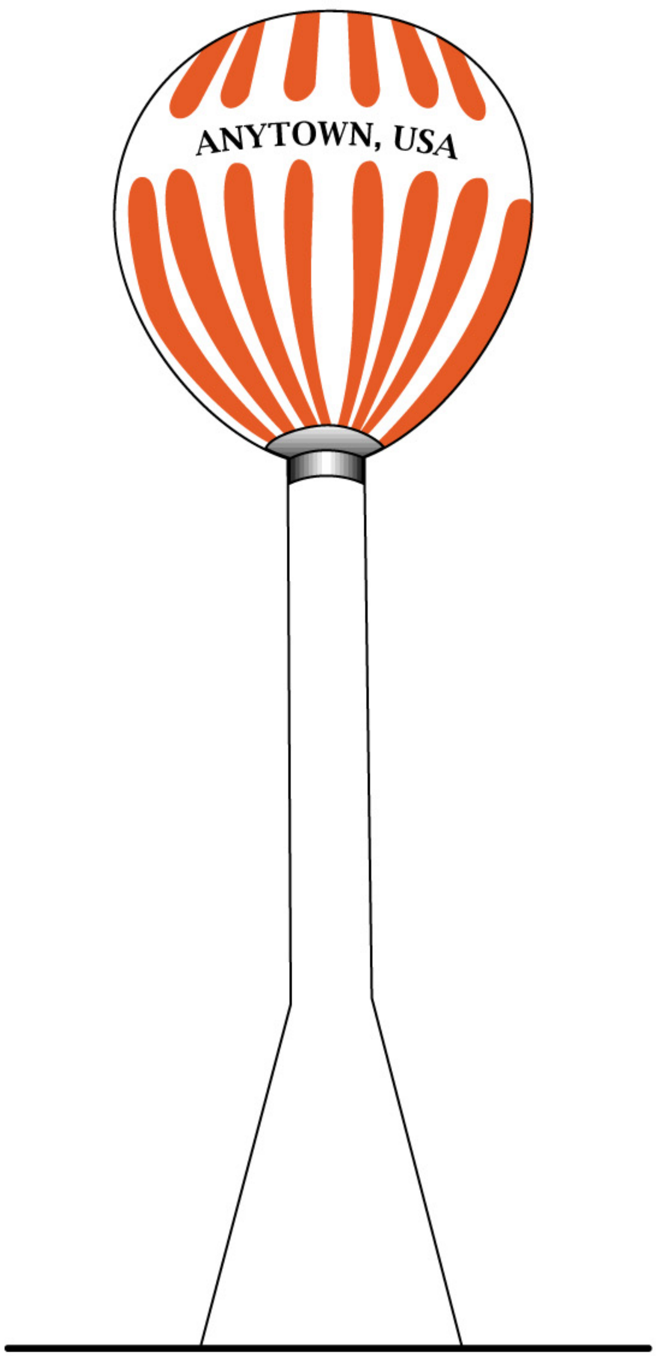


FIG 5

LIGHTING ADJACENT STRUCTURES

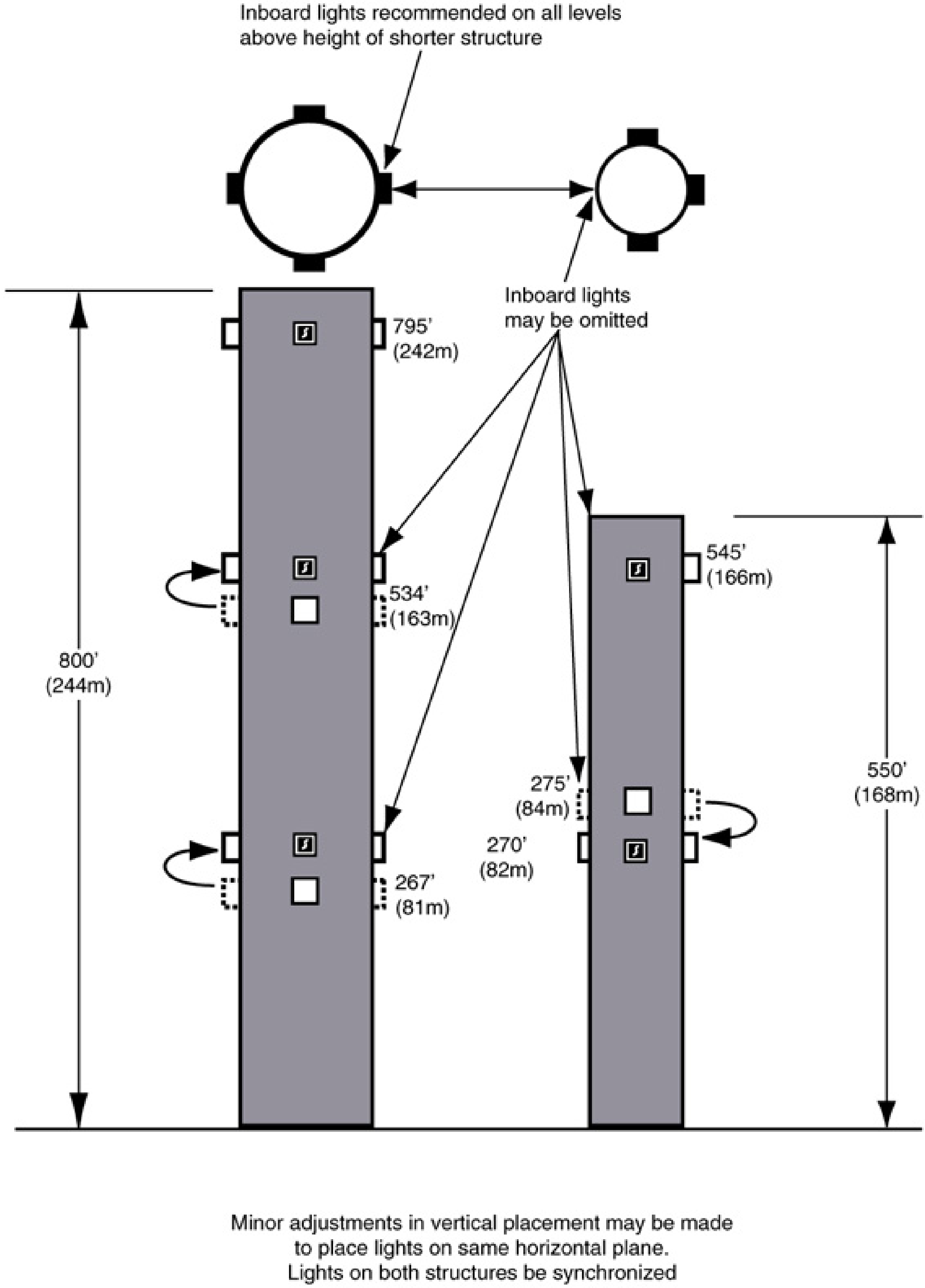


FIG 6

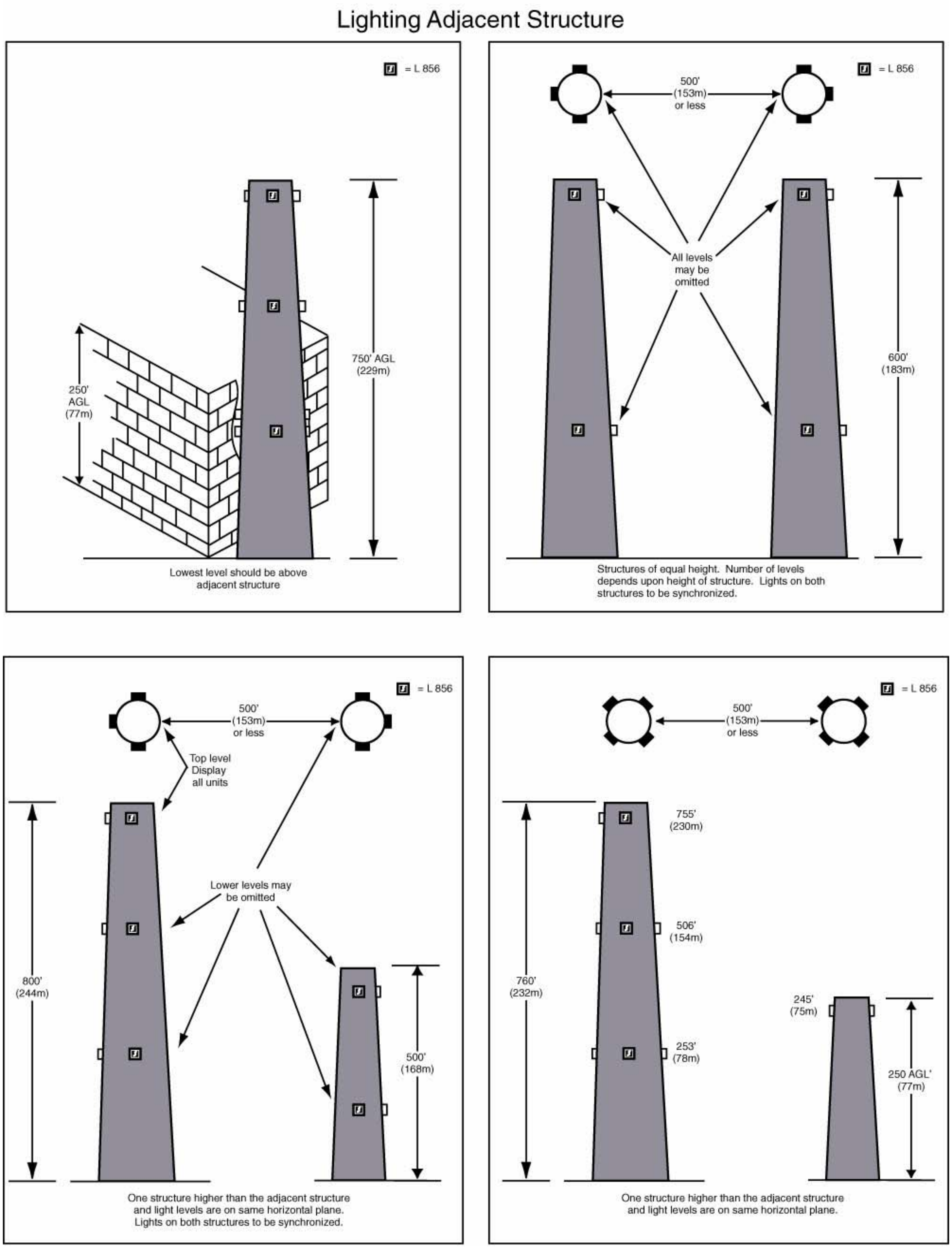

Lighting Adjacent Structure
= L 856
250' AGL (77m)
750' AGL (229m)
Lowest level should be above adjacent structure
500' (153m) or less
All levels may be omitted
600' (183m)
Structures of equal height. Number of levels depends upon height of structure. Lights on both structures to be synchronized.
Top level Display all units
Lower levels may be omitted
800' (244m)
500' (168m)
One structure higher than the adjacent structure and light levels are on same horizontal plane. Lights on both structures to be synchronized.
755' (230m)
506' (154m)
253' (78m)
760' (232m)
245' (75m)
250 AGL' (77m)
One structure higher than the adjacent structure and light levels are on same horizontal plane.

FIG 7

Lighting Adjacent Structure

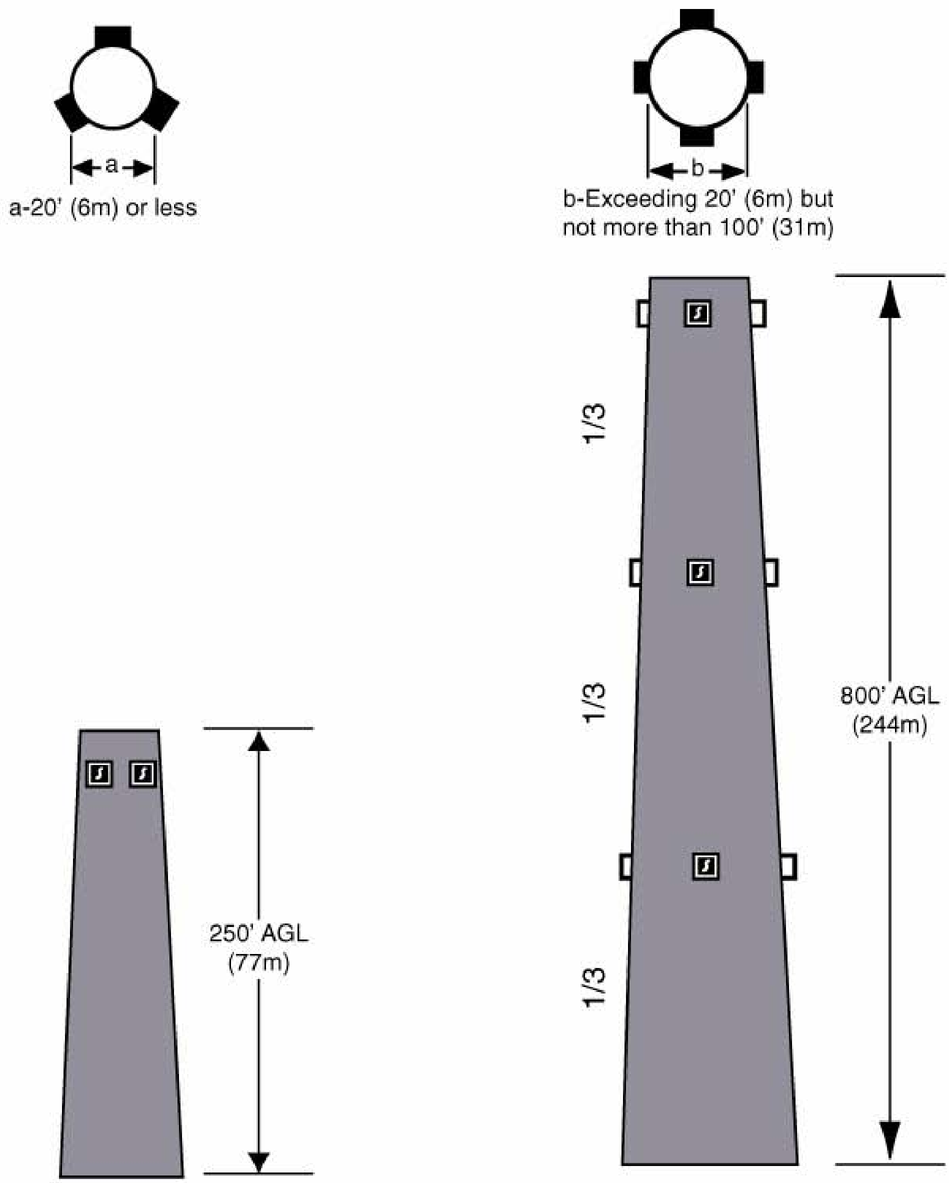


FIG 8

HYPERBOLIC COOLING TOWER

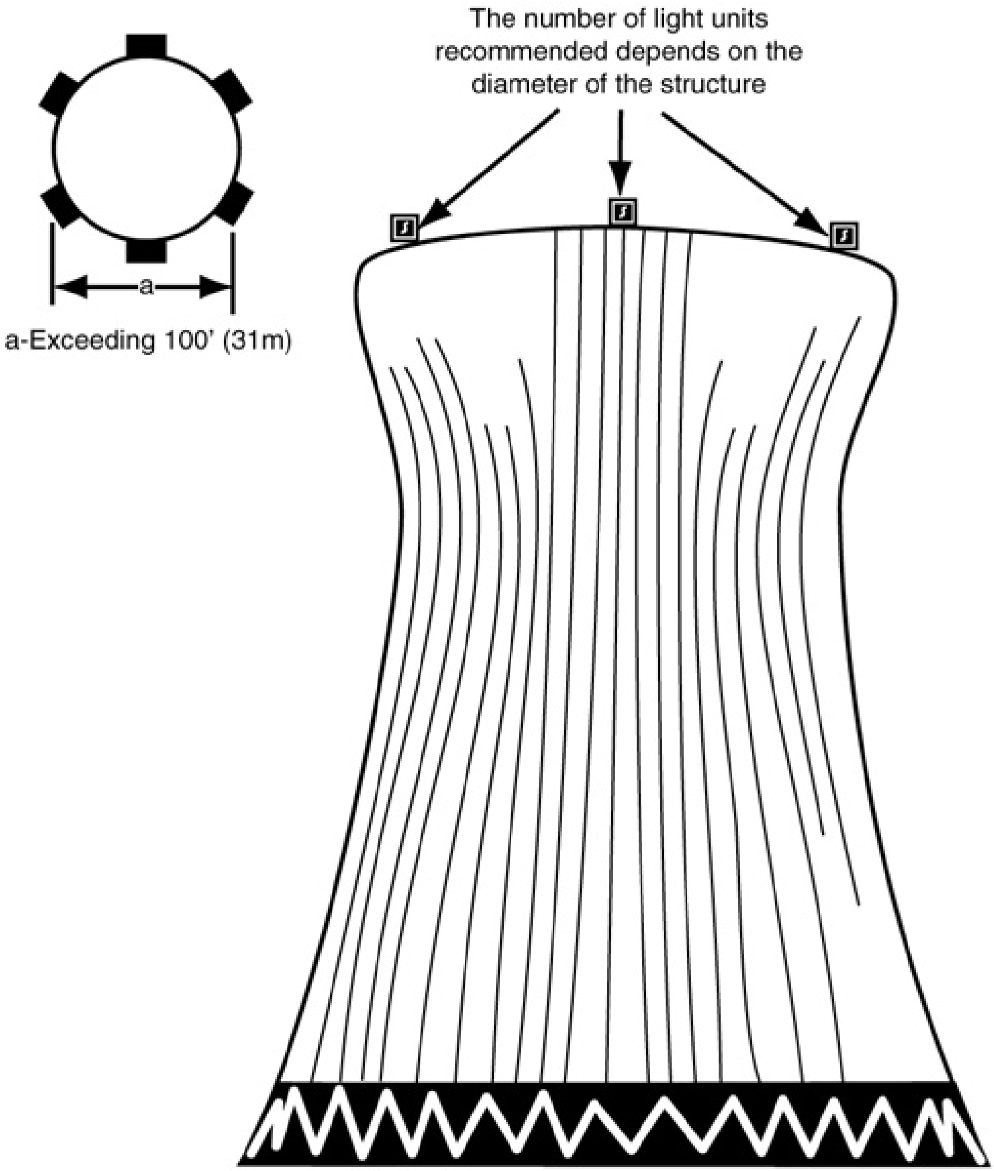


FIG 9

BRIDGE LIGHTING

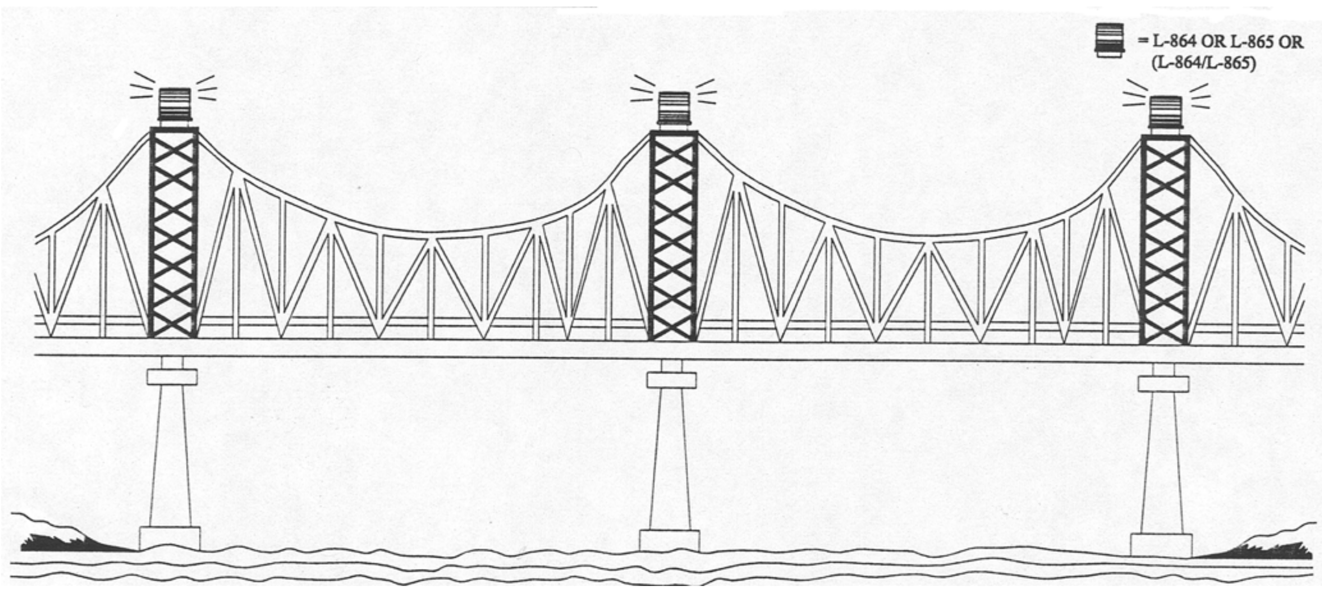


FIG 10

TYPICAL LIGHTING OF A STAND ALONE WIND TURBINE

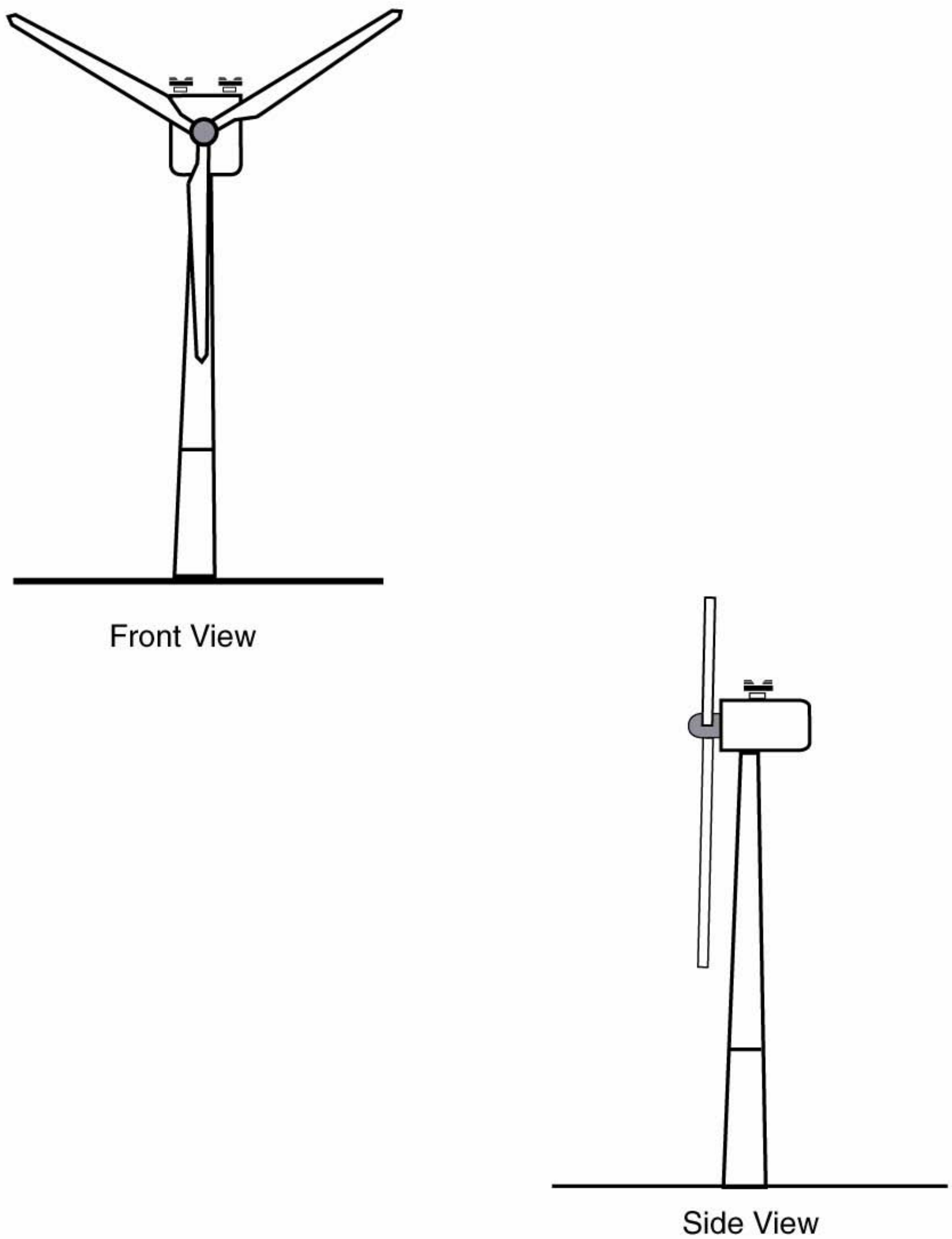


FIG 11

WIND TURBINE GENERATOR

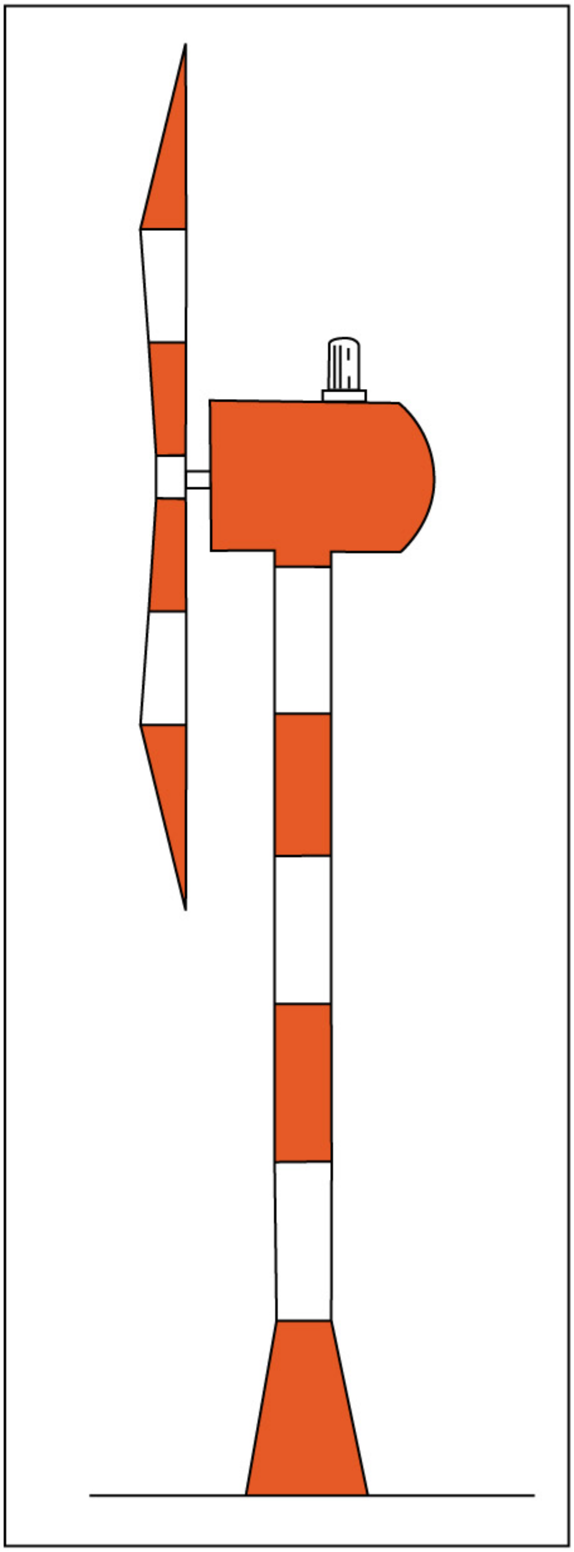


FIG 12

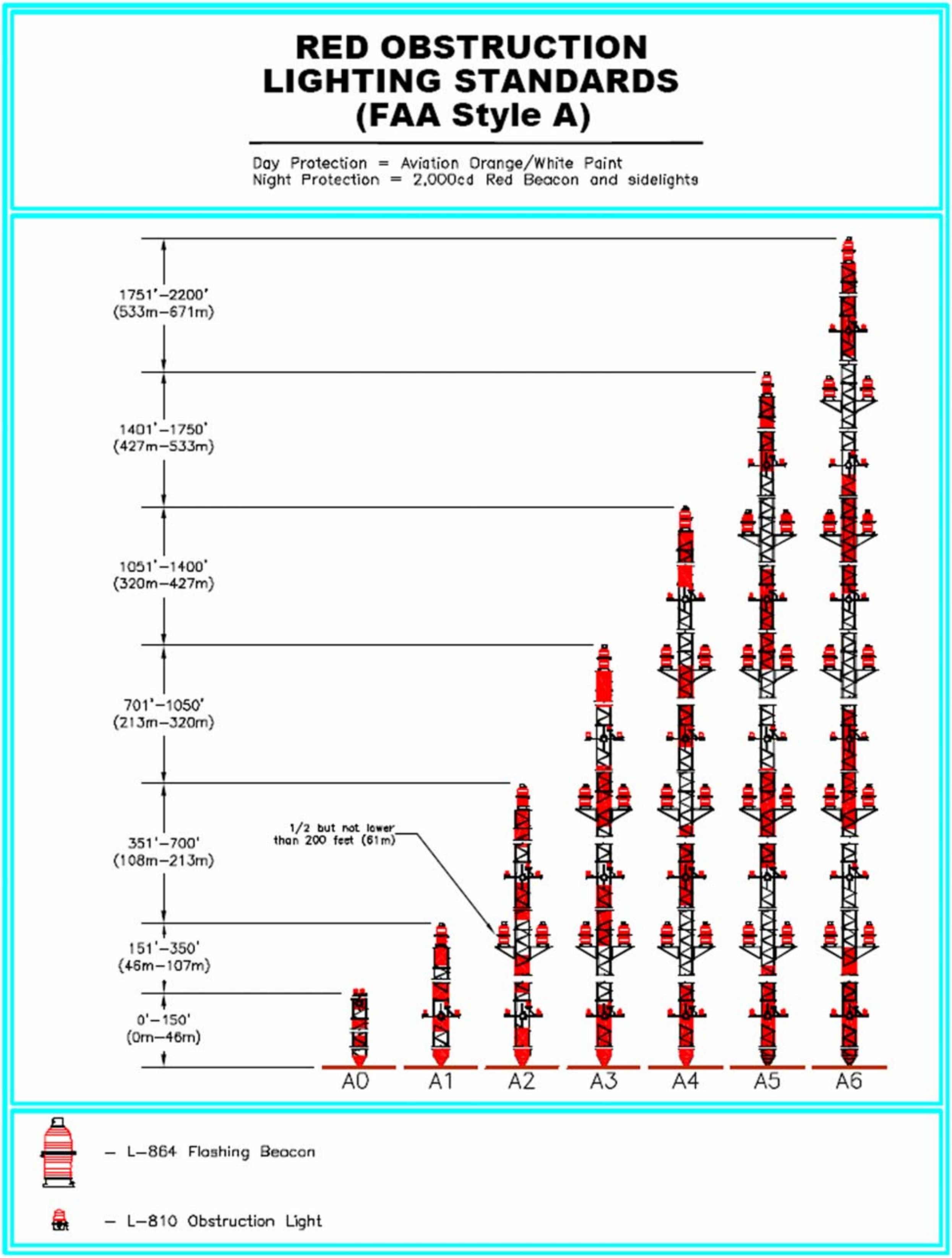
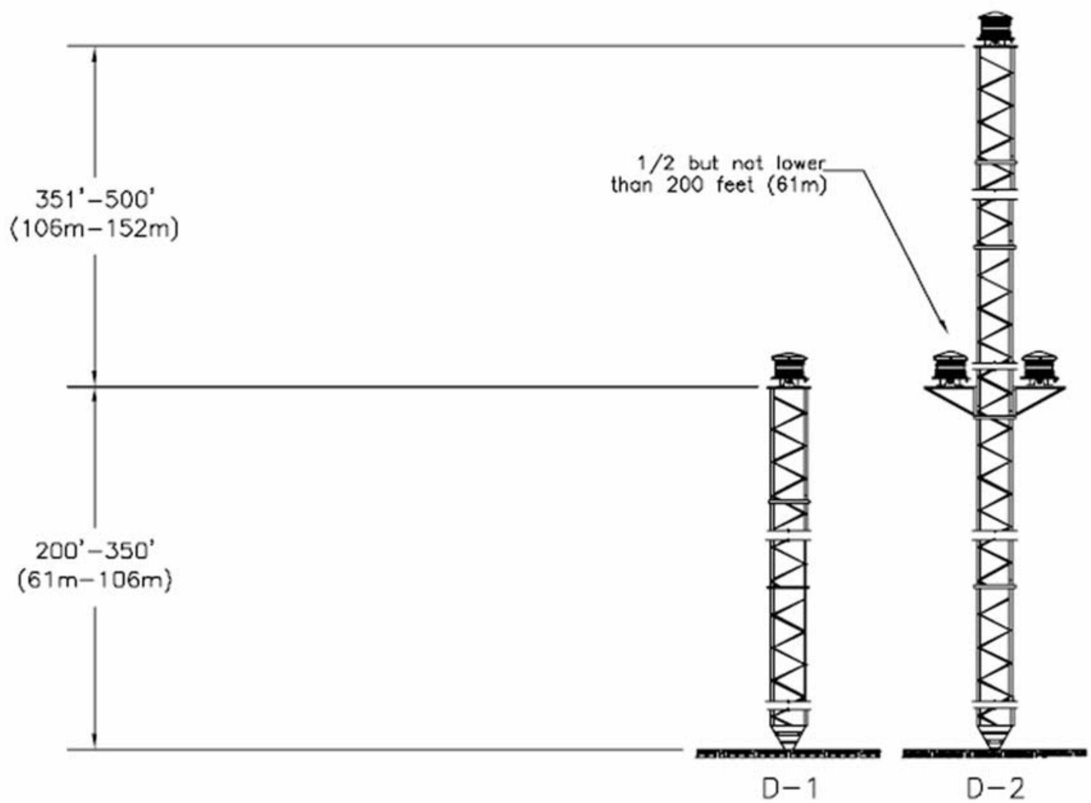

RED OBSTRUCTION
LIGHTING STANDARDS
(FAA Style A)
Day Protection = Aviation Orange/White Paint
Night Protection = 2,000cd Red Beacon and sidelights
1751'–2200'
(533m–671m)
1401'–1750'
(427m–533m)
1051'–1400'
(320m–427m)
701'–1050'
(213m–320m)
351'–700'
(108m–213m)
1/2 but not lower than 200 feet (61m)
151'–350'
(46m–107m)
0'–150'
(0m–46m)
A0
A1
A2
A3
A4
A5
A6
– L–864 Flashing Beacon
– L–810 Obstruction Light

FIG 13

MEDIUM INTENSITY WHITE OBSTRUCTION LIGHTING STANDARDS (FAA Style D)

Day/Twilight Protection = 20,000cd White Strobe
Night Protection = 2,000cd White Strobe
Painting of tower is typically not required.



 – L-865 Flashing White Strobe

FIG 14

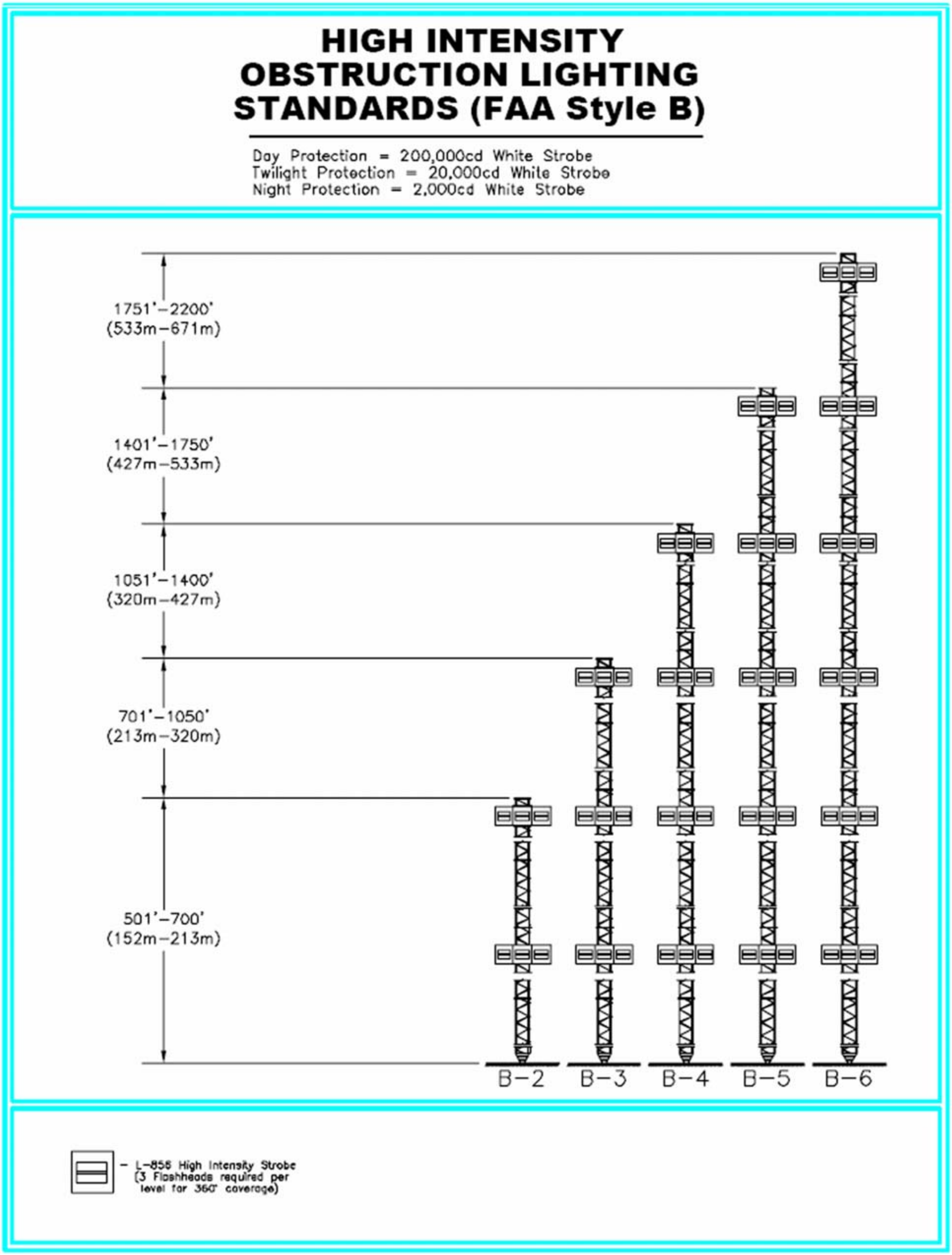

HIGH INTENSITY
OBSTRUCTION LIGHTING
STANDARDS (FAA Style B)
Day Protection = 200,000cd White Strobe
Twilight Protection = 20,000cd White Strobe
Night Protection = 2,000cd White Strobe
1751'–2200'
(533m–671m)
1401'–1750'
(427m–533m)
1051'–1400'
(320m–427m)
701'–1050'
(213m–320m)
501'–700'
(152m–213m)
B–2
B–3
B–4
B–5
B–6
– L–856 High Intensity Strobe
(3 Flashheads required per
level for 360° coverage)

FIG 15

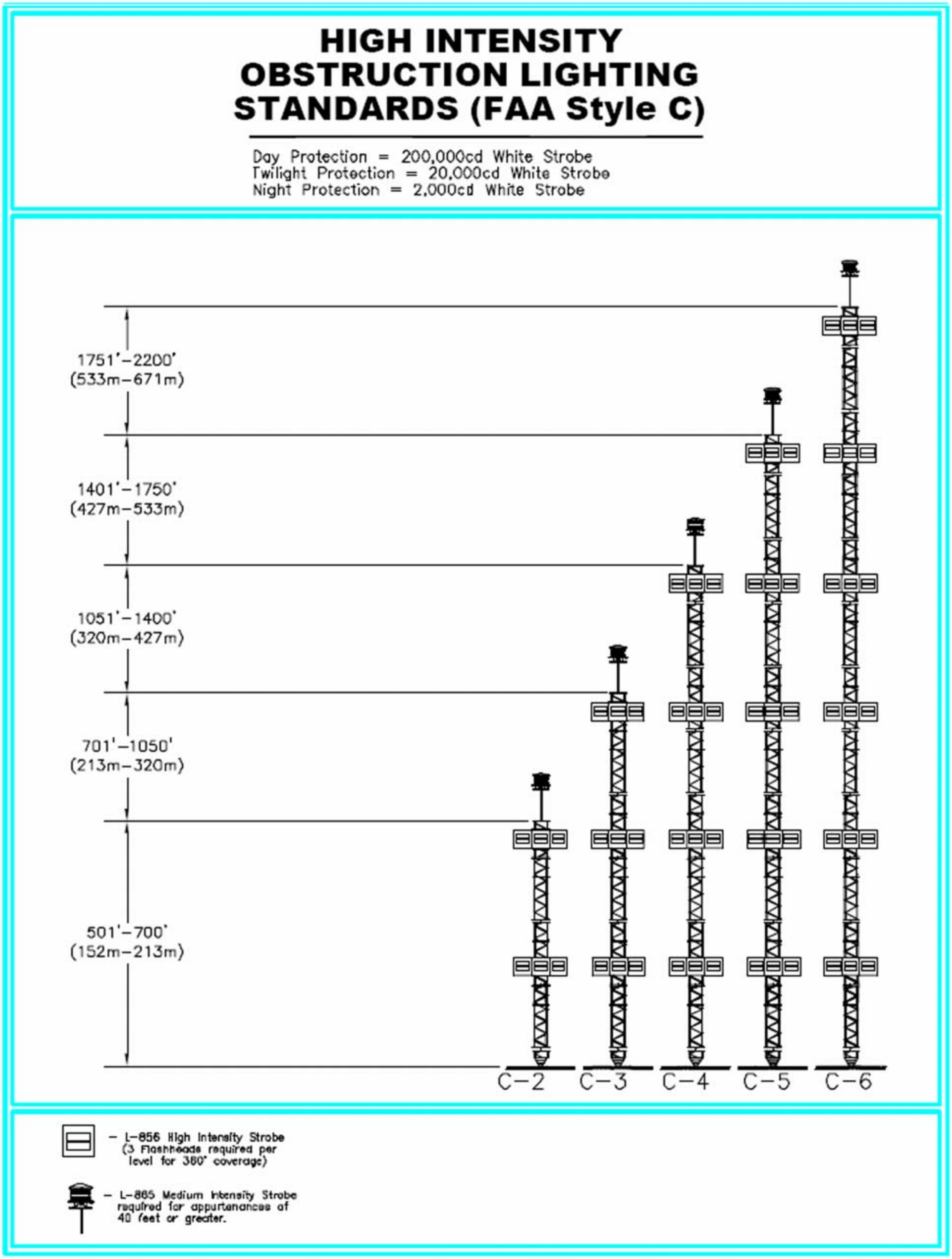

HIGH INTENSITY
OBSTRUCTION LIGHTING
STANDARDS (FAA Style C)
Day Protection = 200,000cd White Strobe
Twilight Protection = 20,000cd White Strobe
Night Protection = 2,000cd White Strobe
1751'–2200' (533m–671m)
1401'–1750' (427m–533m)
1051'–1400' (320m–427m)
701'–1050' (213m–320m)
501'–700' (152m–213m)
C–2
C–3
C–4
C–5
C–6
– L-856 High Intensity Strobe (3 Flashheads required per level for 360° coverage)
– L-865 Medium Intensity Strobe required for appurtenances of 40 feet or greater.

FIG 16

MEDIUM INTENSITY DUAL OBSTRUCTION LIGHTING STANDARDS (FAA Style E)

Day/Twilight Protection = 20,000cd White Strobe
Night Protection = 2,000cd Red Strobe and sidelights
Painting of tower is typically not required.

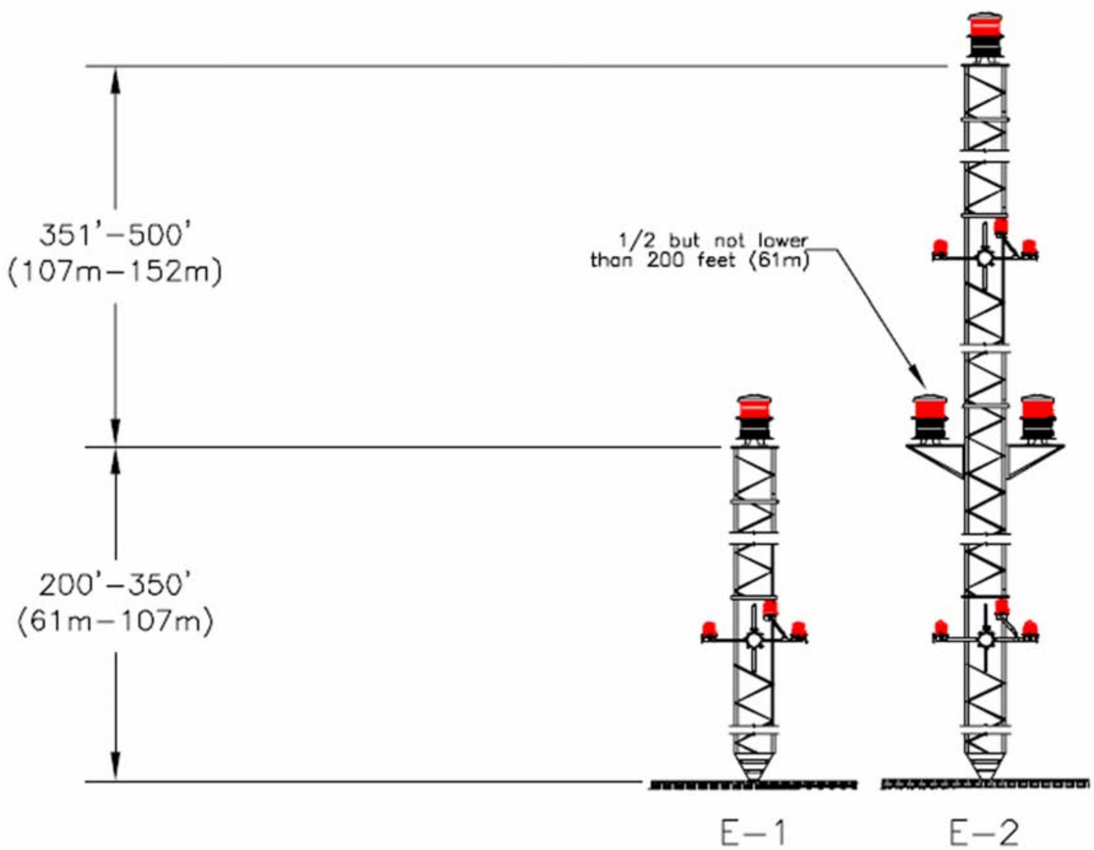
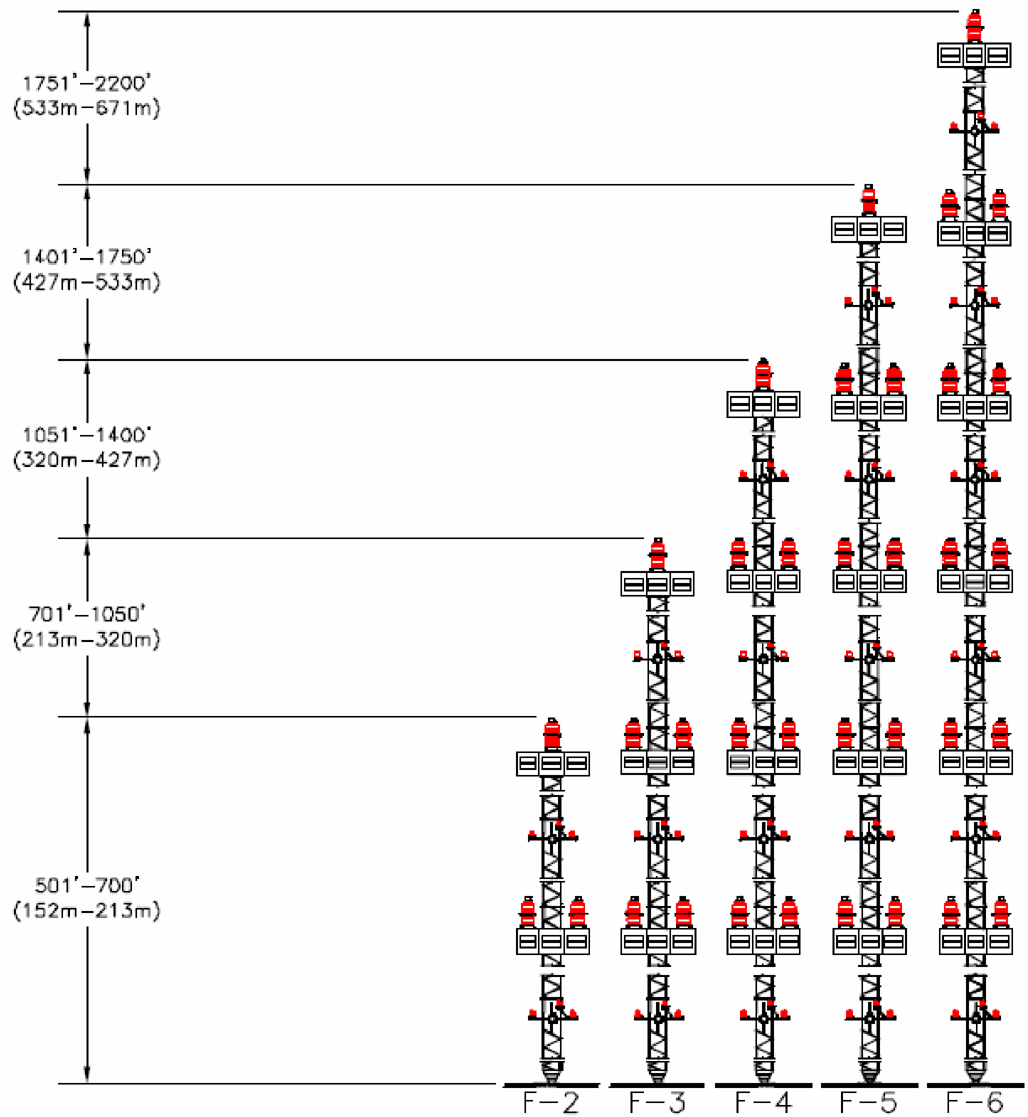


FIG 17

DUAL HIGH INTENSITY OBSTRUCTION LIGHTING STANDARDS (FAA Style F)

Day Protection = 200,000cd White Strobe
Twilight Protection = 20,000cd White Strobe
Night Protection = 2,000cd Red Beacon and sidelights



– L–864 Flashing Beacon

– L–810 Obstruction Light

– L–856 High Intensity Strobe (3 Flashheads required per level for 360° coverage)

FIG 18

APPENDIX 2. Miscellaneous

1. RATIONALE FOR OBSTRUCTION LIGHT INTENSITIES.

Sections 91.117, 91.119 and 91.155 of the FAR Part 91, General Operating and Flight Rules, prescribe aircraft speed restrictions, minimum safe altitudes, and basic visual flight rules (VFR) weather minimums for governing the operation of aircraft, including helicopters, within the United States.

2. DISTANCE VERSUS INTENSITIES.

TBL 5 depicts the distance the various intensities can be seen under 1 and 3 statute miles meteorological visibilities:

Distance/Intensity Table

Time Period	*Meteorological Visibility Statute Miles*	*Distance Statute Miles*	*Intensity Candelas*
Night		**2.9 (4.7km)**	**1,500 (+/- 25%)**
	3 (4.8km)	**3.1 (4.9km)**	**2,000 (+/- 25%)**
		1.4 (2.2km)	**32**
Day		**1.5 (2.4km)**	**200,000**
	1 (1.6km)	**1.4 (2.2km)**	**100,000**
		1.0 (1.6km)	**20,000 (+/- 25%)**
Day		**3.0 (4.8km)**	**200,000**
	3 (4.8km)	**2.7 (4.3km)**	**100,000**
		1.8 (2.9km)	**20,000 (+/- 25%)**
Twilight	**1 (1.6km)**	**1.0 (1.6km) to 1.5 (2.4km)**	**20,000 (+/- 25%)**?
Twilight	**3 (4.8km)**	**1.8 (2.9km) to 4.2 (6.7km)**	**20,000 (+/- 25%)**?

Note-
1. DISTANCE CALCULATED FOR NORTH SKY ILLUMINANCE.

TBL 5

3. CONCLUSION.

Pilots of aircraft travelling at 165 knots (190 mph/306kph) or less should be able to see obstruction lights in sufficient time to avoid the structure by at least 2,000 feet (610m) horizontally under all conditions of operation, provided the pilot is operating in accordance with FAR Part 91. Pilots operating between 165 knots (190 mph/303 km/h) and 250 knots (288 mph/463 kph) should be able to see the obstruction lights unless the weather deteriorates to 3 statute miles (4.8 kilometers) visibility at night, during which time period 2,000 candelas would be required to see the lights at 1.2 statute miles (1.9km). A higher intensity, with 3 statute miles (4.8 kilometers) visibility at night, could generate a residential annoyance factor. In addition, aircraft in these speed ranges can normally be expected to operate under instrument flight rules (IFR) at night when the visibility is 1 statute mile (1.6 kilometers).

4. DEFINITIONS.

a. Flight Visibility. The average forward horizontal distance, from the cockpit of an aircraft in flight, at which prominent unlighted objects may be seen and identified by day and prominent lighted objects may be seen and identified by night.

Reference-
AIRMAN'S INFORMATION MANUAL
PILOT/CONTROLLER GLOSSARY.

b. Meteorological Visibility. A term that denotes the greatest distance, expressed in statute miles, that selected objects (visibility markers) or lights of moderate intensity (25 candelas) can be seen and identified under specified conditions of observation.

5. LIGHTING SYSTEM CONFIGURATION.

a. *Configuration A.* Red lighting system.

b. *Configuration B.* High Intensity White Obstruction Lights (including appurtenance lighting).

c. *Configuration C.* Dual Lighting System - High Intensity White & Red (including appurtenance lighting).

d. *Configuration D.* Medium Intensity White Lights (including appurtenance lighting).

e. *Configuration E.* Dual Lighting Systems - Medium Intensity White & Red (including appurtenance lighting).

Example-
''CONFIGURATION B 3'' DENOTES A HIGH INTENSITY LIGHTING SYSTEM WITH THREE LEVELS OF LIGHT.

Angelina National Forest
(936) 897-1068

Caddo / LBJ National Grasslands
(940) 627-5475

Davy Crockett National Forest
(936) 655-2299

Sabine National Forest
(409) 625-1940

Sam Houston National Forest
(936) 344-6205

Southern Research Station Lab
(936) 569-7981

National Forests & Grasslands in Texas
415 S. First Street,
Suite 110
Lufkin, Texas 75901

Caddo-LBJ National Grasslands

~ Caddo Maps (Ladonia Unit & Bois D' Arc Unit) - LBJ Map ~

The Caddo and Lyndon B. Johnson (LBJ) National Grasslands are located in two areas northeast and northwest of the Dallas-Fort Worth metroplex. They not only provide grazing land for cattle and habitat for wildlife, but offer a variety of recreation. The most popular activities are hiking, camping, fishing, hunting, horseback riding, mountain biking, wildlife viewing, and photography.

White-tailed deer, small mammals, coyotes, bobcats, red fox, waterfowl, bobwhite quail, turkey, and songbirds thrive in the diverse habitats provided by the Grasslands. Largemouth bass, blue and channel catfish, and various sunfish species are common catches at the many lakes that dot the Grasslands' landscape.

The recreation areas on the Caddo and LBJ offer a variety of facilities for camping, picnicking, and other outdoor activities. All are open year-round . Group users should check with the District office several weeks in advance of their scheduled visit to determine if a permit is required. Horseback riders are reminded that horses are not allowed in Forest Service developed recreation areas. When using undeveloped sites, do not tie horses to trees or where they can damage the trees. The use of picket lines between trees or trailers is permitted. Please remember to PACK OUT everything you PACKED IN.

> ### Warning
>
> **Wild Animal Warning:** Our national forests are a refuge for wild animals, including dangerous animals like bears, alligators and venomous snakes. Wild animals can be upset by human presence and can unexpectedly become aggressive. Do not give them a reason or an opportunity to attack. Always keep your distance. Your safety is your responsibility.

A Texas hunting/fishing license is required when hunting or fishing on the Grasslands. On

Phone: (936)-639-8501
Fax : (936)-639-8588
TDD : (936)-639-8560

the CADDO, a Texas Public Hunting Permit is also required.

Hunters should be extremely careful as all areas of the Grasslands are used heavily during hunting season by hunters and the non-hunting public alike. Fluorescent orange is REQUIRED on all hunters during any permitted season with a minimum of 144 square inches visible on both the chest and back and a fluorescent orange cap or hat. (Exception: When hunting migratory birds and turkeys.) It is recommended non-hunters also wear fluorescent material during the hunting season as an extra safety precaution.

Due to extremely erosive soils, vehicle travel on both the LBJ and Caddo is restricted to designated Forest Service system and gravel-surfaced roads.

Grasses and other herbaceous vegetation on the Grasslands are highly flammable. When using undeveloped sites, campfires should be built on bare ground and must be attended at all times. Before leaving your camp, make sure any fire is completely extinguished.

Permits for fuelwood cutting for home use ($20 for two cords) are available at the District office in Decatur and the Caddo Work Center in Honey Grove. Firewood for campfires is limited to downed wood only, with no permit required. Cutting standing trees or pruning limbs from them is prohibited.

Administrative maps are available for $9 each (if requesting by mail, add $1.00 for postage per map).

CADDO NATIONAL GRASSLANDS

The CADDO is comprised of 17,785 acres and contains three lakes. The largest, Lake Coffee Mill, is 651 acres with one developed recreation area containing 13 picnic units and an improved boat ramp. Lake Davy Crockett is 388 acres in size and has two developed recreation areas. West Lake Davy Crockett has 11 camping units, while the east side has four picnic units and an improved boat ramp. There is a $2 day-use fee at Coffee Mill and West Lake Davy Crockett. A $4 per night camping fee is charged for using camping sites at West Lake Davy Crockett. Drinking water is available at both lakes. Forty-five acre Lake Fannin is accessible for fishing from the east side only and has an unimproved earthen boat launch site.

LYNDON B. JOHNSON NATIONAL GRASSLANDS

The LBJ is comprised of more than 20,250 acres with one developed recreation area located at Black Creek Lake. The recreation area consists of seven picnic units, seven walk-in camp units, one improved boat ramp and an accessible fishing bridge. No drinking water is available. The lake is approximately 30 acres in size. The discharge of firearms and hunting is prohibited on and around the lake.

Cottonwood Lake, located 5 miles north of Black Creek Lake, is approximately 40 acres in size and has one improved boat ramp. No recreation facilities are provided. The discharge of firearms is prohibited in the vicinity of Cottonwood Lake. However, from November 1 through February 28, the use of shotguns, excluding slugs and buckshot, for legally hunting game birds and game animals during state designated seasons is permitted.

The Cottonwood-Black Creek Hiking Trail is 4 miles long and connects the two lakes. It is rated moderately difficult. There are nearly 75 miles of multipurpose trails which run in the Cottonwood Lake vicinity.

TADRA Point is a designated trailhead camping facility that is a primary access point for the 75 mile LBJ Multiuse Trail system. Restrooms and parking facilities are provided.

Valley View Group Use Campground is available by reservation on weekends. Call the Caddo-LBJ district office at (940)-627-5475 for reservations. Weekend reservations are $150.00. This money is used to maintain the facility and improve the campground. Facilities include restrooms, parking spurs, fire rings, lantern posts and group pavilion.

Other popular lakes include Clear Lake and Rhodes Lake. Clear Lake is approximately 20 acres in size and has a concrete boat ramp and a 50-foot wheelchair accessible fishing pier. Rhodes Lake is approximately 15 acres and has no facilities.

FULLY AUTOMATIC WEAPONS ARE PROHIBITED. Hunting is limited to shotguns, muzzleloaders and archery. Unit 3 is open to target shooting with shotguns; and hunting and camping are permitted.

U.S. Fish & Wildlife Service

Endangered Species List

Back to Start

List of species by county for Texas:

Counties Selected: Austin

Select one or more counties from the following list to view a county list:

Anderson
Andrews
Angelina
Aransas
Archer

View County List

Austin County

Common Name	Scientific Name	Species Group	Listing Status	Species Image	Species Distribution Map	Critical Habitat	More Info
Attwater's greater prairie-chicken	*Tympanuchus cupido attwateri*	Birds	E				P
bald eagle	*Haliaeetus leucocephalus*	Birds	DM				P
Houston toad	*Bufo houstonensis*	Amphibians	E				P
sharpnose Shiner	*Notropis oxyrhynchus*	Fishes	C	No Image			P
whooping crane	*Grus americana*	Birds	E, EXPN				P

U.S. Fish & Wildlife Service

Endangered Species List

Back to Start

List of species by county for Texas:

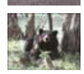
Counties Selected: Fannin

Select one or more counties from the following list to view a county list:

Anderson
Andrews
Angelina
Aransas
Archer

View County List

Fannin County

Common Name	Scientific Name	Species Group	Listing Status	Species Image	Species Distribution Map	Critical Habitat	More Info
bald eagle	*Haliaeetus leucocephalus*	Birds	DM				P
least tern	*Sterna antillarum*	Birds	E				P
Louisiana black bear	*Ursus americanus luteolus*	Mammals	T				P

U.S. Fish & Wildlife Service

Endangered Species List

Back to Start

List of species by county for Texas:

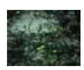
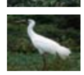
Counties Selected: Fort Bend

Select one or more counties from the following list to view a county list:

Anderson
Andrews
Angelina
Aransas
Archer

View County List

Fort Bend County

Common Name	Scientific Name	Species Group	Listing Status	Species Image	Species Distribution Map	Critical Habitat	More Info
bald eagle	*Haliaeetus leucocephalus*	Birds	DM				P
sharpnose Shiner	*Notropis oxyrhynchus*	Fishes	C	No Image			P
Texas prairie dawn-flower	*Hymenoxys texana*	Flowering Plants	E				P
whooping crane	*Grus americana*	Birds	E, EXPN				P

U.S. Fish & Wildlife Service

Endangered Species List

Back to Start

List of species by county for Texas:

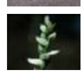
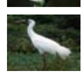
Counties Selected: Freestone

Select one or more counties from the following list to view a county list:

Anderson
Andrews
Angelina
Aransas
Archer

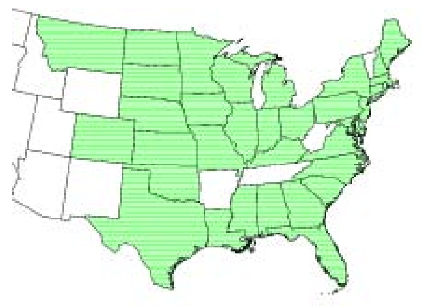
View County List

Freestone County

Common Name	Scientific Name	Species Group	Listing Status	Species Image	Species Distribution Map	Critical Habitat	More Info
bald eagle	*Haliaeetus leucocephalus*	Birds	DM				P
large-fruited sand-verbena	*Abronia macrocarpa*	Flowering Plants	E				P
least tern	*Sterna antillarum*	Birds	E				P
Navasota ladies'-tresses	*Spiranthes parksii*	Flowering Plants	E				P
whooping crane	*Grus americana*	Birds	E, EXPN				P

Species Profile

Environmental Conservation Online System



Quick links: [Federal Register](#) [Recovery](#) [Critical Habitat](#) [Conservation Plans](#) [Petitions](#) [Life History](#) [Other Resources](#)

General Information

Size: 18 cm (7.25 in) in length. Color: Breeding season: Pale brown above, lighter below; black band across forehead; bill orange with black tip; legs orange; white rump. Male: Complete or incomplete black band encircles the body at the breast. Female: Paler head band; incomplete breast band. Winter coloration: Bill black; all birds lack breast band and head band.

Population detail

The FWS is currently monitoring the following populations of the Piping Plover

- **Population location:** Great Lakes watershed in States of IL, IN, MI, MN, NY, OH, PA, and WI and Canada (Ont.)
  Listing status: Endangered
  States/US Territories in which this population is known to occur: Illinois , Indiana , Michigan , Minnesota , New York , Ohio , Pennsylvania , Wisconsin
  USFWS Refuges in which this population is known to occur: AMAGANSETT NATIONAL WILDLIFE REFUGE , ELIZABETH ALEXANDRA MORTON NATIONAL WILDLIFE REFUGE , FERGUS FALLS WETLAND MANAGEMENT DISTRICT , MORRIS WETLAND MANAGEMENT DISTRICT , TARGET ROCK NATIONAL WILDLIFE REFUGE
  Countries in which the this population is known to occur: Canada
  For more information: http://ecos.fws.gov/docs/life_histories/B079.html
- **Population location:** Entire, except those areas where listed as endangered above
  Listing status: Threatened
  States/US Territories in which this population is known to occur: Alabama , Colorado , Connecticut , Delaware , Florida , Georgia , Indiana , Iowa , Kansas , Kentucky , Louisiana , Maine , Maryland , Massachusetts , Minnesota , Mississippi , Missouri , Montana , Nebraska , New Hampshire , New Jersey , New York , North Carolina , North Dakota , Ohio , Oklahoma , Puerto Rico , Rhode Island , South Carolina , South Dakota , Texas , Virginia , Wisconsin
  USFWS Refuges in which this population is known to occur: ANAHUAC NATIONAL WILDLIFE REFUGE , ARANSAS NATIONAL WILDLIFE REFUGE , ARROWWOOD NATIONAL WILDLIFE REFUGE , AUDUBON NATIONAL WILDLIFE REFUGE , AUDUBON WETLAND MANAGEMENT DISTRICT **... Show All Refuges**
  Countries in which the this population is known to occur: Canada , Mexico
  For more information: http://ecos.fws.gov/docs/life_histories/B079.html

Current Listing Status Summary

Status	Date Listed	Lead Region	Where Listed
Endangered	12/11/1985	Great Lakes-Big Rivers Region (Region 3)	Great Lakes watershed
Threatened	12/11/1985	Northeast Region (Region 5)	except Great Lakes watershed

» Federal Register Documents

Most Recent Federal Register Documents (Showing 5 of 28 : view all)

Date	Citation Page	Title
05/19/2009	74 FR 23475 23600	Revised Designation of Critical Habitat for the Wintering Population of the Piping Plover (Charadrius melodus) in Texas
10/21/2008	73 FR 62815 62841	Revised Designation of Critical Habitat for the Wintering Population of the Piping Plover (Charadrius melodus) in North Carolina; Final Rule
09/30/2008	73 FR 56860 56862	Endangered and Threatened Wildlife and Plants; 5-Year Review - Notice of initiation of review; request for information on the piping plover (Charadrius melodus).
06/09/2008	73 FR 32629	Correction to Revised Designation of Critical Habitat for the Wintering Population of the Piping Plover (Charadrius melodus) in Texas
05/20/2008	73 FR 29293 29321	Revised Designation of Critical Habitat for the Wintering Population of the Piping Plover (Charadrius melodus) in Texas: Proposed rule.

» Recovery

Recovery Plan Information Search

- Information Search FAQs

Current Recovery Plan(s)

Date	Title	Plan Action Status	Plan Status
05/12/1988	Great Lakes & Northern Great Plains Piping Plover	View Implementation Progress	Final
05/02/1996	Piping Plover Atlantic Coast Population Revised Recovery Plan	View Implementation Progress	Final Revision 1
09/16/2003	Recovery Plan for the Great Lakes population of Piping Plovers	View Implementation Progress	Final

Other Recovery Documents (Showing 5 of 6 : view all)

Date	Citation Page	Title	Document Type
09/30/2008	73 FR 56860 56862	Endangered and Threatened Wildlife and Plants; 5-Year Review - Notice of initiation of review; request for information on the piping plover (Charadrius melodus).	• Notice 5-year Review, Initiation
09/16/2003	68 FR 54241 54242	Approved Recovery Plan for the Great Lakes Piping Plover (Charadrius melodus)	• Notice Final Recovery Plan Availability
08/05/2002	67 FR 50687 50688	Notice of Availability of the Piping Plover (Charadrius melodus) Great Lakes Population Draft Recovery Plan for Review and Comment	• Notice Draft Recovery Plan Availability
12/28/2001	66 FR 67165 67166	ETWP; Proposed Designation of Critical Habitat for the Northern Great Plains Breeding Population of the Piping Plover; Reopening of Public Comment Period and Notice of Availability of Draft Economic Analysis	• Notice Doc. Availability • Notice Reopen Comment • Proposed Critical Habitat, Critical habitat--birds
09/19/2000	65 FR 56530 56531	Reopening of Comment Period and Notice of Availability of Draft Economic Analysis on Proposed Critical Habitat Designation for	• Notice Doc. Availability • Notice Reopen

	the Great Lakes Breeding Population of the Piping Plover	Comment	

» Critical Habitat

Current Critical Habitat Documents (Showing 5 of 12 : view all)

Date	Citation Page	Title	Document Type	Status
05/19/2009	74 FR 23475 23600	Revised Designation of Critical Habitat for the Wintering Population of the Piping Plover (Charadrius melodus) in Texas	Final Rule	Active
10/21/2008	73 FR 62815 62841	Revised Designation of Critical Habitat for the Wintering Population of the Piping Plover (Charadrius melodus) in North Carolina; Final Rule	Final Rule	Not Required
05/20/2008	73 FR 29293 29321	Revised Designation of Critical Habitat for the Wintering Population of the Piping Plover (Charadrius melodus) in Texas: Proposed rule.	Proposed Rule	Not Required
09/11/2002	67 FR 57637 57717	Endangered and Threatened Wildlife and Plants; Designation of Critical Habitat for the Northern Great Plains Breeding Population of the Piping Plover; Final Rule	Final Rule	Not Required
12/28/2001	66 FR 67165 67166	ETWP; Proposed Designation of Critical Habitat for the Northern Great Plains Breeding Population of the Piping Plover; Reopening of Public Comment Period and Notice of Availability of Draft Economic Analysis	Proposed Rule	Not Required

To learn more about critical habitat please see **http://criticalhabitat.fws.gov**

» Conservation Plans

Habitat Conservation Plans (HCP) (learn more) (Showing 3 of 3)

HCP Plan Summaries
Magic Carpet Woods Association
Piping Plover HCP (State of Massachusetts)
Volusia Beaches

» Petitions

No petition findings have been published for the Piping Plover.

» Life History

No Life History information has been entered into this system for this species.

» Other Resources

NatureServe Explorer Species Reports -- NatureServe Explorer is a source for authoritative conservation information on more than 50,000 plants, animals and ecological communtities of the U.S and Canada. NatureServe Explorer provides in-depth information on rare and endangered species, but includes common plants and animals too. NatureServe Explorer is a product of NatureServe in collaboration with the Natural Heritage Network.

ITIS Reports -- ITIS (the Integrated Taxonomic Information System) is a source for authoritative taxonomic information on plants

ITIS Reports -- ITIS (the Integrated Taxonomic Information System) is a source for authoritative taxonomic information on plants, animals, fungi, and microbes of North America and the world.

Last updated: October 15, 2009

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Piping plover

Charadrius melodus

SPECIES CODE: B079 V01 and V02

STATUS:

Listed Endangered (50 FR 50726-50734, 1985 December 11) in Great Lakes watershed in the States of Illinois, Indiana, Michigan, Minnesota, New York, Ohio, Pennsylvania, and Wisconsin and in Ontario, Canada. Critical Habitat for the Great Lakes Breeding Population designated May 7, 2001 (66 FR 22938-22969). Recovery Plan completed September 8, 2003.

Listed Threatened (50 FR 50726-50734, 1985, December 11) in entire range except in the Great Lakes watershed where listed Endangered. Critical Habitat for the Northern Great Plains Breeding Population designated September 11, 2002 (), and Revised Recovery Plan for the Atlantic Coast Population completed May 2, 1996.

Critical Habitat for wintering plovers designated July 10, 2001 (66 FR 36038-36143).

SPECIES DESCRIPTION:

The piping plover is a small, stocky, sandy-colored bird resembling a sandpiper. The adult has yellow-orange legs, a black band across the forehead from eye to eye, and a black ring around the base of its neck. Like other plovers, it runs in short starts and stops. When still, the piping plover blends into the pale background of open, sandy habitat on outer beaches where it feeds and nests. The bird's name derives from its call notes, plaintive bell-like whistles which are often heard before the birds are seen.

REPRODUCTION AND DEVELOPMENT:

Piping plovers return to their breeding grounds in late March or early April. Following establishment of nesting territories and courtship rituals, the pair forms a depression in the sand. The nest is sometimes lined with small stones or fragments of shell. Both sexes incubate to constantly protect eggs from extreme temperatures. The average clutch size is four eggs and the precocial downy young immediately use the “peck-and-run” foraging behavior of adults. When predators or intruders come close, the young squat motionless on the sand while the parents attempt to attract the attention of the intruders to themselves, often by feigning a broken wing. Plovers will renest and fledglings from these late nesting efforts may not be flying until late August. Plovers often gather in groups on undisturbed beaches prior to their southward migration. By mid-September, both adult and young plovers will have departed from their wintering areas. Piping plovers may live to be 8-10 years old.

RANGE AND POPULATION LEVEL:

The Atlantic Coast Population of piping plovers nest along beaches in New Brunswick, Prince Edward Island, Nova Scotia, Quebec, southern Maine, Rhode Island, Massachusetts, Connecticut, New York, New Jersey, Delaware, Maryland, Virginia, and North Carolina. These birds winter primarily on the Atlantic Coast from North Carolina to Florida, although some migrate to the Bahamas and West Indies. Surveys completed in 1991 found fewer than 2,500 breeding pairs remained in the United States and Canada. Surveys completed in 1999 estimated the Atlantic population at less than 1400 pairs.

The historic breeding range of the Great Lakes population of piping plover encompasses the Great Lakes' shorelines in Illinois, Indiana, Michigan, Minnesota, Ohio, Pennsylvania, Wisconsin, New York and Ontario. Great Lakes breeding sites are currently restricted to several beaches along Lake Superior and Lake Michigan in northern Michigan. These birds winter primarily on the Gulf Coast, in Texas, Louisiana, Alabama and Florida. Critical habitat for the Great Lakes Piping plover has been designated for breeding habitat along the shorelines of the Great Lakes in New York, Minnesota, Illinois, Indiana, Michigan, Ohio, Pennsylvania, and Wisconsin. Critical habitat for wintering piping plovers has been designated along the Gulf Coast in Texas, Louisiana, Alabama and Florida. Surveys completed in 2001 reported 32 breeding pairs in the United States.

The current breeding range of the Northern Great Plains population of piping plover extends from alkali wetlands in southeastern Alberta through southern Saskatchewan and Manitoba to Lake of the Woods in southwestern Ontario and northwestern Minnesota, south along major prairie rivers (Yellowstone, Missouri, Niobrara, Platte, and Loup), the Prewitt Reservoir in northeastern Colorado, northwestern Oklahoma, and alkali wetlands in northeastern Montana, North Dakota, South Dakota, Nebraska, and Iowa. These birds winter primarily on the Gulf Coast, in Texas, Louisiana, Alabama and Florida. Critical habitat for the Northern Great Plains piping plover has been designated in areas of Texas, Louisiana, Alabama and Florida for their wintering habitat along the gulf coats; and areas of Minnesota, Montana, North Dakota, South Dakota, and Nebraska for breeding habitat. Surveys completed in 2001 estimated 5,938 individuals remained in the United States and Canada.

HABITAT:

Atlantic Coast piping plovers utilize the open, sandy beaches close to the primary dune of the barrier islands and coastlines of the Atlantic for breeding. They prefer sparsely vegetated open sand, gravel, or cobble for a nest site. They forage along the rack line where the tide washes up onto the beach.

Great Lakes piping plovers utilize the open, sandy beaches, barrier islands, and sand spits formed along the Great Lakes' perimeters by wave action. They do not inhabit lakeshore areas where high bluffs formed by severe erosion have replaced beach habitat. They prefer sparsely vegetation open sand, gravel, or cobble for a nest site. They forage along the rack line where invertebrates are most readily available.

Northern Great Plains piping plovers favor wide, sparsely vegetated sand or gravel beaches adjacent to vast alkali lakes such as Big Quill Lake, Sask., or West Shoal Lake, Man. They also use washed-out hillside beaches on smaller semipermanent alkali wetlands such as Chain of Lakes in central North Dakota. Areas adjacent to these are pastures or rangeland consisting of mid- or short-grass prairie. On rivers, plovers use beaches, sandflats, dredge islands, and drained river floodplains. They forage near the water where invertebrates are most readily available.

In the winter, all three populations inhabit beaches, mudflats, and sandflats along the Gulf of Mexico and Atlantic coasts. Also barrier island beaches and spoil islands on the Gulf Intercoastal Waterway.

PAST THREATS:

The piping plover nearly disappeared due to excessive hunting for the millinery trade during the 19th century.

CURRENT THREATS:

The current population decline of the Atlantic Coast population is attributed to increased development and recreational use of beaches since the end of World War II. Human disturbance often curtails breeding success. Developments near beaches also provide food that attracts increased numbers of predators such as raccoons, skunks, and foxes, and domestic pets. Stormtides may inundate nests.

The Great Lakes population decline is attributed to losses of lakeshore habitat due to huge fluctuations in lake levels caused by intensive water management throughout the watershed and in the St. Lawrence River, as well as increased development and recreational use of beaches. Human disturbance often curtails breeding success. Developments near beaches also provide food that attracts increased numbers of predators such as raccoons, skunks, and foxes, and domestic pets. Stormtides may inundate nests.

The Northern Great Plains piping plover population decline is attributed to destruction of vegetated sandbars and river islands for flood control and navigation, and water level regulation policies that endanger nesting habitat. Rapidly raising water levels during nesting or brood rearing causes low reproductive success. Sand pit operations on some rivers draw breeders onto sterile beach environments where chicks find little food.

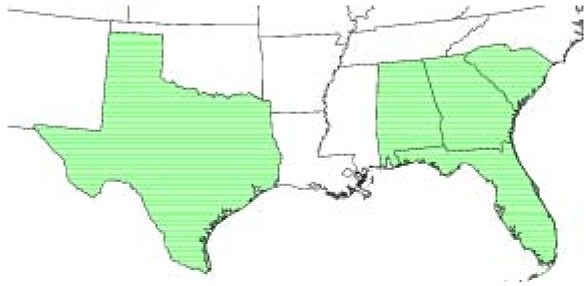
CONSERVATION MEASURES:

LITERATURE CITED:

Haig, S.M. 1992. Piping Plover. *In* The Birds of North America, No.2 (A. Poole, P. Stettenheim, and F. Gill, Eds.). Philadelphia: The Academy of Natural Sciences; Washington, DC: The American Ornithologists' Union.

Species Profile

Environmental Conservation Online System



Quick links: Federal Register Recovery Critical Habitat Conservation Plans Petitions Life History Other Resources

General Information

Wood storks are large, long-legged wading birds, about 5O inches tall, with a wingspan of 60 to 65 inches. The plumage is white except for black primaries and secondaries and a short black tail. The head and neck are largely unfeathered and dark gray in color. The bill is black, thick at the base, and slightly decurved. Immature birds are dingy gray and have a yellowish bill.

Lead Region: Southeast Region (Region 4)

Date Listed: Feb 28, 1984
Where Listed: U.S.A. (AL, FL, GA, SC)

States/US Territories in which the Wood stork, AL, FL, GA, SC is known to occur: Alabama , Florida , Georgia , South Carolina , Texas
USFWS Refuges in which the Wood stork, AL, FL, GA, SC is known to occur: ACE BASIN NATIONAL WILDLIFE REFUGE , ANAHUAC NATIONAL WILDLIFE REFUGE , ARANSAS NATIONAL WILDLIFE REFUGE , ARTHUR R. MARSHALL LOXAHATCHEE NATIONAL WILDLIFE REFUGE , BANKS LAKE NATIONAL WILDLIFE REFUGE **... Show All Refuges**
For more information: **http://www.fws.gov/northflorida/Species-Accounts/SpeciesInfo.htm**

» Federal Register Documents

Most Recent Federal Register Documents (Showing 4 of 4)

Date	Citation Page	Title
09/27/2006	71 FR 56545 56547	**Endangered and Threatened Wildlife and Plants; 5-Year Review of 37 Southeastern Species**
02/28/1984	49 FR 7332 7335	**US Breeding Population of Wood Stork Determined to be End.; 49 FR 7332- 7335**
02/28/1983	48 FR 8402 840	**Proposed End. Status for US Breeding Population of Wood Stork (Mycteria americana); 48 FR 8402-8404**
12/30/1982	47 FR 58454 58460	**Review of Vertebrate Wildlife for Listing as End. or Thr. Species**

» Recovery

Recovery Plan Information Search

Current Recovery Plan(s)

Date	Title	Plan Action Status	Plan Status
01/27/1997	**Revised Recovery Plan for the U.S. Breeding Population of the Wood Stork**	**View Implementation Progress**	Final Revision 1

Other Recovery Documents (Showing 1 of 1)

Date	Citation Page	Title	Document Type
09/27/2006	71 FR 56545 56547	**Endangered and Threatened Wildlife and Plants; 5-Year Review of 37 Southeastern Species**	• Notice 5-year Review, Initiation

Five Year Review

Date	Title
09/21/2007	**Wood Stork 5-Year Review**

» Critical Habitat

No critical habitat rules have been published for the Wood stork, AL, FL, GA, SC.

» Conservation Plans

No conservation plans have been created for Wood stork, AL, FL, GA, SC

» Petitions

No petition findings have been published for the Wood stork, AL, FL, GA, SC.

» Life History

Habitat Requirements

The southeast United States breeding population of the wood stork declined from an estimated 20,000 pairs in the 1930's to about 10,000 pairs by 1960, and to a low of approximately 5,000 pairs in the late 1970s. Nesting primarily occurred in the Everglades. The generally accepted explanation for the decline of the wood stork is the reduction in food base (primarily small fish) necessary to support breeding colonies. This reduction is attributed to loss of wetland habitat as well as to changes in water hydroperiods from draining wetlands and changing water regimes by constructing levees, canals, and floodgates to alter water flow in south Florida. Wood storks have a unique feeding technique and require higher prey concentrations than other wading birds. Optimal water regimes for the wood stork involve periods of flooding, during which prey (fish) populations increase, alternating with dryer periods, during which receding water levels concentrate fish at higher densities coinciding with the stork's nesting season. Loss of nesting habitat (primarily cypress swamps) may be affecting wood storks in central Florida, where nesting in non-native trees and in man-made impoundments has been occurring recently. Less significant factors known to affect nesting success include prolonged drought and flooding, raccoon predation on nests, and human disturbance of rookeries.

Food Habits

Small fish from 1 to 6 inches long, especially topminnows and sunfish, provide this bird's primary diet. Wood storks capture their prey by a specialized technique known as grope-feeding or tacto-location. Feeding often occurs in water 6 to 10 inches deep, where a stork probes with the bill partly open. When a fish touches the bill it quickly snaps shut. The average response time of this reflex is 25 milliseconds, making it one of the fastest reflexes known in vertebrates. Wood storks use thermals to soar as far as 80 miles from nesting to feeding areas. Since thermals do not form in early morning, wood storks may arrive at feeding areas later than other wading bird species such as herons. Energy requirements for a pair of nesting wood storks and their young is estimated at 443 pounds of fish for the breeding season (based on an average production of 2.25 fledglings per nest).

Movement / Home Range

The current population of adult birds is difficult to estimate, since not all nest each year. Presently, the wood stork breeding population is believed to be greater than 8,000 nesting pairs (16,000 breeding adults). Nesting has been restricted to Florida, Georgia, and South Carolina, however they may have formerly bred in most of the southeastern United States and Texas. A second distinct, non-endangered population of wood storks breeds from Mexico to northern Argentina. Storks from both populations move northward after breeding, with birds from the southeastern United States population moving as far north as North Carolina on the Atlantic coast and into Alabama and eastern Mississippi along the Gulf coast, and storks from Mexico moving up into Texas and Louisiana and as far north as Arkansas and Tennessee along the Mississippi River Valley. There have been occasional sightings in all States along and east of the Mississippi River, and sporadic sightings in some States west of the Mississippi and in Ontario.

Reproductive Strategy

The wood stork is a highly colonial species usually nesting in large rookeries and feeding in flocks. Age at first breeding is

3 years but typically do so at 4. Nesting periods vary geographically. In South Florida, wood storks lay eggs as early as October and fledge in February or March. However, in north and central Florida, Georgia, and South Carolina, storks lay eggs from March to late May, with fledging occurring in July and August. Nests are frequently located in the upper branches of large cypress trees or in mangroves on islands. Several nests are usually located in each tree. Wood storks have also nested in man-made structures. Storks lay two to five eggs, and average two young fledged per successful nest under good conditions.

» Other Resources

NatureServe Explorer Species Reports -- NatureServe Explorer is a source for authoritative conservation information on more than 50,000 plants, animals and ecological communtities of the U.S and Canada. NatureServe Explorer provides in-depth information on rare and endangered species, but includes common plants and animals too. NatureServe Explorer is a product of NatureServe in collaboration with the Natural Heritage Network.

ITIS Reports -- ITIS (the Integrated Taxonomic Information System) is a source for authoritative taxonomic information on plants, animals, fungi, and microbes of North America and the world.

Last updated: July 1, 2009

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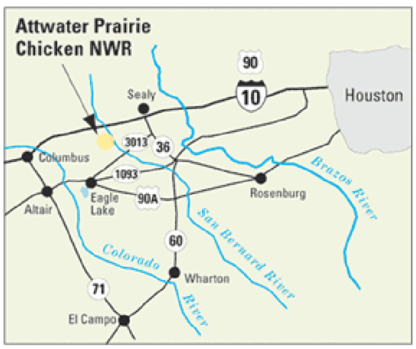
U.S. Fish & Wildlife Service
Southwest Region 2

Attwater Prairie Chicken

National Wildlife Refuge

Attwater Prairie Chicken National Wildlife Refuge (NWR), located approximately 60 miles west of Houston, Texas, is one of the largest remnants of coastal prairie habitat remaining in southeast Texas and home to one of the last populations of the critically endangered Attwater's prairie-chicken, a ground-dwelling grouse of the coastal prairie ecosystem. Formerly occupying some 6 million acres of coastal prairie habitat, the Attwater's prairie-chicken was once one of the most abundant resident birds of the Texas and Louisiana tall grass prairie ecosystem. Presently, less than 200,000 fragmented acres of coastal prairie habitat remain, leaving the birds scattered among two Texas counties. The refuge is one of a handful of national wildlife refuges managed specifically for an endangered species; however, recovery activities for this imperiled bird and management of it's declining ecosystem go beyond the refuge's boundaries.

2009 Attwater's Prairie Chicken Festival



Download Attwater Vicinity Map (609Kb, PDF)

How to Get There

The refuge is located 6.5 miles northeast of Eagle Lake, off FM 3013, or south from Sealy on Highway 36 to FM 3013 and traveling west for 10 miles. Headquarters is located 2 miles west of the main entrance on FM 3013.

Refuge Quick Facts

When was it established? 1972
How big is it? 10,528 acres
Why is it here? To preserve and restore coastal prairie habitat for the critically endangered Attwater's prairie-chicken.

Attwater's prairie-chicken, photo by George Levandoski.

Click to hear the peculiar sound the male makes during his intricate courtship dance – it's all a part of impressing the female.

Food and Shelter: How Volunteers Are Helping to Save the Endangered Attwater's Prairie Chicken

It is no secret that the Attwater's prairie chicken (APC) is extremely endangered and on the brink of extinction, mainly due to environmental changes such as significant loss of habitat due to urbanization. The birds are dependent upon reintroduction from captivity, and the protection that the Attwater Prairie Chicken National Wildlife Refuge can provide. There are only two wild populations left, both of which live on wildlife refuges in Texas. This year however, thanks in part to the help of volunteers, the future of the APC is finally beginning to look brighter. More...

U.S. Fish & Wildlife Service

Endangered Species List

Back to Start

List of species by county for Texas:

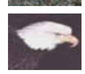
Counties Selected: Austin

Select one or more counties from the following list to view a county list:

Anderson
Andrews
Angelina
Aransas
Archer

View County List

Austin County

Common Name	Scientific Name	Species Group	Listing Status	Species Image	Species Distribution Map	Critical Habitat	More Info
Attwater's greater prairie-chicken	*Tympanuchus cupido attwateri*	Birds	E				P
bald eagle	*Haliaeetus leucocephalus*	Birds	DM				P
Houston toad	*Bufo houstonensis*	Amphibians	E				P
sharpnose Shiner	*Notropis oxyrhynchus*	Fishes	C	No Image			P
whooping crane	*Grus americana*	Birds	E, EXPN				P

U.S. Fish & Wildlife Service

Endangered Species List

Back to Start

List of species by county for Texas:

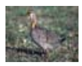
Counties Selected: Colorado

Select one or more counties from the following list to view a county list:

Anderson
Andrews
Angelina
Aransas
Archer

View County List

Colorado County

Common Name	Scientific Name	Species Group	Listing Status	Species Image	Species Distribution Map	Critical Habitat	More Info
Attwater's greater prairie-chicken	*Tympanuchus cupido attwateri*	Birds	E				P
bald eagle	*Haliaeetus leucocephalus*	Birds	DM				P
Houston toad	*Bufo houstonensis*	Amphibians	E				P
whooping crane	*Grus americana*	Birds	E, EXPN				P

U.S. Fish & Wildlife Service

Endangered Species List

Back to Start

List of species by county for Texas:

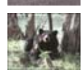
Counties Selected: Fannin

Select one or more counties from the following list to view a county list:

Anderson
Andrews
Angelina
Aransas
Archer

View County List

Fannin County

Common Name	Scientific Name	Species Group	Listing Status	Species Image	Species Distribution Map	Critical Habitat	More Info
bald eagle	*Haliaeetus leucocephalus*	Birds	DM				P
least tern	*Sterna antillarum*	Birds	E				P
Louisiana black bear	*Ursus americanus luteolus*	Mammals	T				P

U.S. Fish & Wildlife Service

Endangered Species List

Back to Start

List of species by county for Texas:

Counties Selected: Fort Bend

Select one or more counties from the following list to view a county list:

Anderson
Andrews
Angelina
Aransas
Archer

View County List

Fort Bend County

Common Name	Scientific Name	Species Group	Listing Status	Species Image	Species Distribution Map	Critical Habitat	More Info
bald eagle	*Haliaeetus leucocephalus*	Birds	DM				P
sharpnose Shiner	*Notropis oxyrhynchus*	Fishes	C	No Image			P
Texas prairie dawn-flower	*Hymenoxys texana*	Flowering Plants	E				P
whooping crane	*Grus americana*	Birds	E, EXPN				P

U.S. Fish & Wildlife Service

Endangered Species List

Back to Start

List of species by county for Texas:

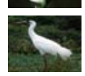
Counties Selected: Freestone

Select one or more counties from the following list to view a county list:

Anderson
Andrews
Angelina
Aransas
Archer

View County List

Freestone County

Common Name	Scientific Name	Species Group	Listing Status	Species Image	Species Distribution Map	Critical Habitat	More Info
bald eagle	*Haliaeetus leucocephalus*	Birds	DM				P
large-fruited sand-verbena	*Abronia macrocarpa*	Flowering Plants	E				P
least tern	*Sterna antillarum*	Birds	E				P
Navasota ladies'-tresses	*Spiranthes parksii*	Flowering Plants	E				P
whooping crane	*Grus americana*	Birds	E, EXPN				P

U.S. Fish & Wildlife Service

Endangered Species List

Back to Start

List of species by county for Texas:

Counties Selected: Wharton

Select one or more counties from the following list to view a county list:

Anderson
Andrews
Angelina
Aransas
Archer

View County List

Wharton County

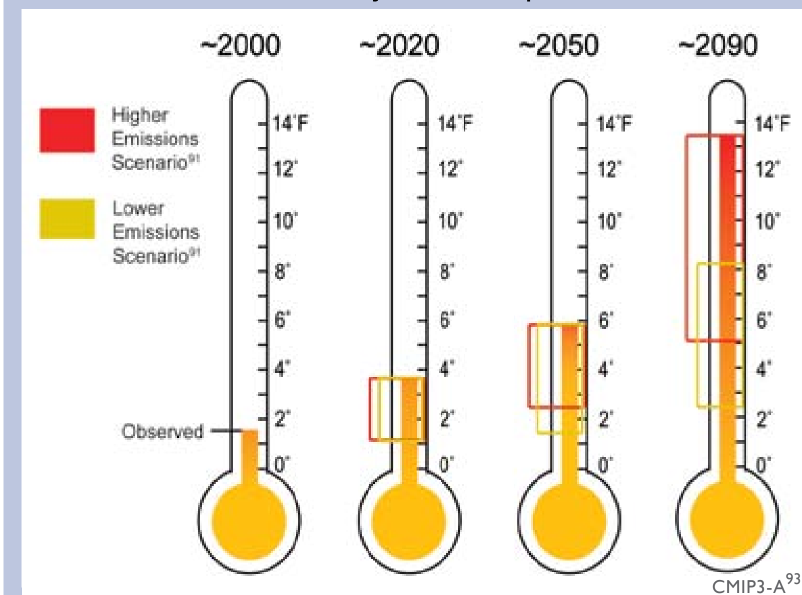
Common Name	Scientific Name	Species Group	Listing Status	Species Image	Species Distribution Map	Critical Habitat	More Info
bald eagle	*Haliaeetus leucocephalus*	Birds	DM				P
whooping crane	*Grus americana*	Birds	E, EXPN				P

Great Plains

The Great Plains is characterized by strong seasonal climate variations. Over thousands of years, records preserved in tree rings, sediments, and sand deposits provide evidence of recurring periods of extended drought (such as the Dust Bowl of the 1930s) alternating with wetter conditions.[97,419]

Today, semi-arid conditions in the western Great Plains gradually transition to a moister climate in the eastern parts of the region. To the north, winter days in North Dakota average 25°F, while it is not unusual to have a West Texas winter day over 75°F. In West Texas, there are between 70 and 100 days per year over 90°F, whereas North Dakota has only 10 to 20 such days on average.

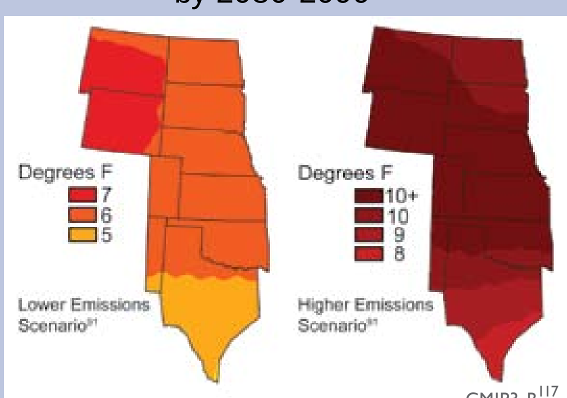
Observed and Projected Temperature Rise



The average temperature in the Great Plains already has increased roughly 1.5°F relative to a 1960s and 1970s baseline. By the end of the century, temperatures are projected to continue to increase by 2.5°F to more than 13°F compared with the 1960 to 1979 baseline, depending on future emissions of heat-trapping gases. The brackets on the thermometers represent the likely range of model projections, though lower or higher outcomes are possible.

Significant trends in regional climate are apparent over the last few decades. Average temperatures have increased throughout the region, with the largest changes occurring in winter months and over the northern states. Relatively cold days are becoming less frequent and relatively hot days more frequent.[420] Precipitation has also increased over most of the area.[149,421]

Summer Temperature Change by 2080-2099



Temperatures in the Great Plains are projected to increase significantly by the end of this century, with the northern part of the region experiencing the greatest projected increase in temperature.

Temperatures are projected to continue to increase over this century, with larger changes expected under scenarios of higher heat-trapping emissions as compared to lower heat-trapping emissions. Summer changes are projected to be larger than those in winter in the southern and central Great Plains.[108] Precipitation is also projected to change, particularly in winter and spring. Conditions are anticipated to become wetter in the north and drier in the south.

Projected changes in long-term climate and more frequent extreme events such as heat waves, droughts, and heavy rainfall will affect many aspects of life in the Great Plains. These include the region's already threatened water resources, essential agricultural and ranching activities, unique natural and protected areas, and the health and prosperity of its inhabitants.

Projected increases in temperature, evaporation, and drought frequency add to concerns about the region's declining water resources.

Water is the most important factor affecting activities on the Great Plains. Most of the water used in the Great Plains comes from the High Plains aquifer (sometimes referred to by the name of its largest formation, the Ogallala aquifer), which stretches from South Dakota to Texas. The aquifer holds both current recharge from precipitation and so-called "ancient" water, water trapped by silt and soil washed down from the Rocky Mountains during the last ice age.

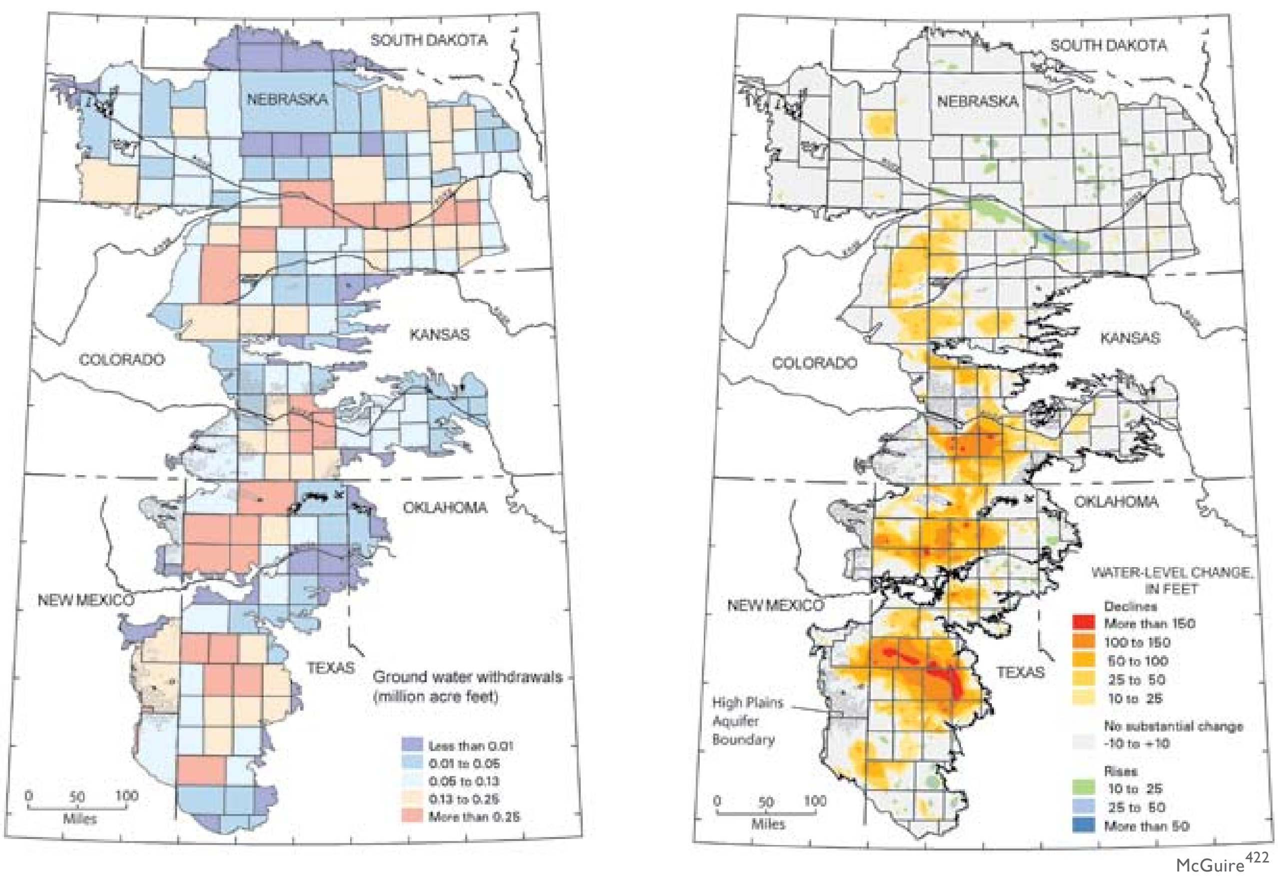
As population increased in the Great Plains and irrigation became widespread, annual water withdrawals began to outpace natural recharge.[422]

Today, an average of 19 billion gallons of groundwater are pumped from the aquifer each day. This water irrigates 13 million acres of land and provides drinking water to over 80 percent of the region's population.[423] Since 1950, aquifer water levels have dropped an average of 13 feet, equivalent to a 9 percent decrease in aquifer storage. In heavily irrigated parts of Texas, Oklahoma, and Kansas, reductions are much larger, from 100 feet to over 250 feet.

Projections of increasing temperatures, faster evaporation rates, and more sustained droughts brought on by climate change will only add more stress to overtaxed water sources.[149,253,424,425] Current water use on the Great Plains is unsustainable, as the High Plains aquifer continues to be tapped faster than the rate of recharge.

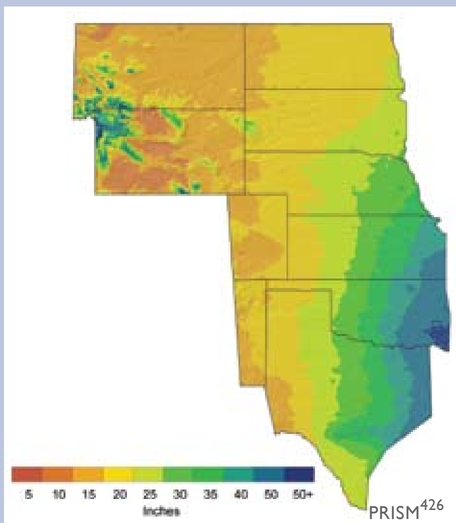
Groundwater Withdrawals for Irrigation
1950 to 2005

Water Level Changes in the High Plains Aquifer
1950 to 2005



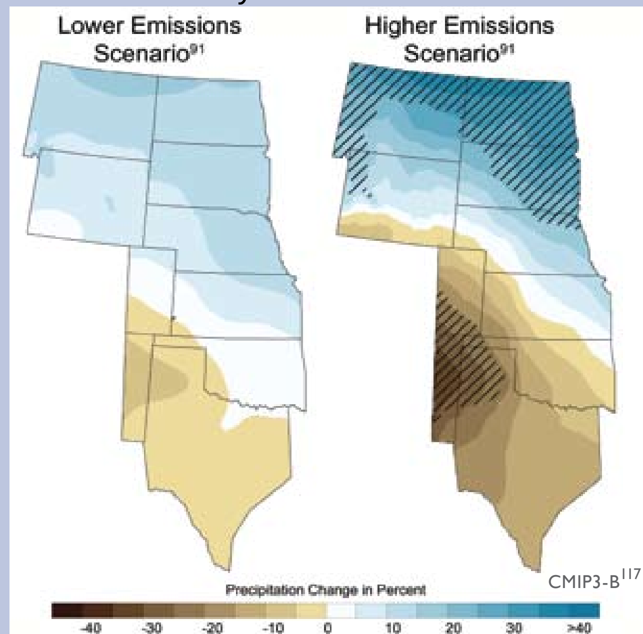
Irrigation is one of the main factors stressing water resources in the Great Plains. In parts of the region, more than 81 trillion gallons of water (pink areas on the left hand map) were withdrawn for irrigation in Texas, Oklahoma, and Kansas from 1950 to 2005. During the same time period, water levels in parts of the High Plains aquifer in those states decreased by more than 150 feet (red areas on the right hand map).

Average Annual Observed Precipitation
1971-2000



The Great Plains currently experiences a sharp precipitation gradient from east to west, from more than 50 inches of precipitation per year in eastern Oklahoma and Texas to less than 10 inches in some of the western parts of the region.

Projected Spring Precipitation Change by 2080s-2090s



Northern areas of the Great Plains are projected to experience a wetter climate by the end of this century, while southern areas are projected to experience a drier climate. The change in precipitation is compared with a 1960-1979 baseline. Confidence in the projected changes is highest in the hatched areas.

The Dust Bowl: Combined Effects of Land Use and Climate

Over the past century, large-scale conversion of grasslands to crops and ranchland has altered the natural environment of the Great Plains.[149] Irrigated fields have increased evaporation rates, reducing summer temperatures, and increasing local precipitation.[427,428]

Dust Bowl of 1935 in Stratford, Texas

The Dust Bowl of the 1930s epitomizes what can happen as a result of interactions between climate and human activity. In the 1920s, increasing demand for food encouraged poor agricultural practices. Small-scale producers ploughed under native grasses to plant wheat, removing the protective cover the land required to retain its moisture.

Variations in ocean temperature contributed to a slight increase in air temperatures, just enough to disrupt the winds that typically draw moisture from the south into the Great Plains. As the intensively tilled soils dried up, topsoil from an estimated 100 million acres of the Great Plains blew across the continent.

The Dust Bowl dramatically demonstrated the potentially devastating effects of poor land-use practices combined with climate variability and change.[429] Today, climate change is interacting with a different set of poor land-use practices. Water is being pumped from the Ogallala aquifer faster than it can recharge. In many areas, playa lakes are poorly managed (see page 127). Existing stresses on water resources in the Great Plains due to unsustainable water usage are likely to be exacerbated by future changes in temperature and precipitation, this time largely due to human-induced climate change.

Agriculture, ranching, and natural lands, already under pressure due to an increasingly limited water supply, are very likely to also be stressed by rising temperatures.

Agricultural, range, and croplands cover more than 70 percent of the Great Plains, producing wheat, hay, corn, barley, cattle, and cotton. Agriculture is fundamentally sensitive to climate. Heat and water stress from droughts and heat waves can decrease yields and wither crops.[430,431] The influence of long-term trends in temperature and precipitation can be just as great.[431]

As temperatures increase over this century, optimal zones for growing particular crops will shift. Pests that were historically unable to survive in the Great Plains' cooler areas are expected to spread northward. Milder winters and earlier springs also will encourage greater numbers and earlier emergence of insects.[149] Rising carbon dioxide levels in the atmosphere can increase crop growth, but also make some types of weeds grow even faster (see *Agriculture* sector).[432]

Projected increases in precipitation are unlikely to be sufficient to offset decreasing soil moisture and water availability in the Great Plains due to rising temperatures and aquifer depletion. In some areas, there is not expected to be enough water for agriculture to sustain even current usage.

With limited water supply comes increased vulnerability of agriculture to climate change. Further stresses on water supply for agriculture and ranching are likely as the region's cities continue to grow, increasing competition between urban and rural users.[433] The largest impacts are expected in heavily irrigated areas in the southern Great Plains, already plagued by unsustainable water use and greater frequency of extreme heat.[149]

Successful adaptation will require diversification of crops and livestock, as well as transitions from irrigated to rain-fed agriculture.[434-436] Producers who can adapt to changing climate conditions are likely to see their businesses survive; some might even thrive. Others, without resources or ability to adapt effectively, will lose out.

Climate change is likely to affect native plant and animal species by altering key habitats such as the wetland ecosystems known as prairie potholes or playa lakes.

Ten percent of the Great Plains is protected lands, home to unique ecosystems and wildlife. The region is a haven for hunters and anglers, with its ample supplies of wild game such as moose, elk, and deer; birds such as goose, quail, and duck; and fish such as walleye and bass.

Climate-driven changes are likely to combine with other human-induced stresses to further increase the vulnerability of natural ecosystems to pests, invasive species, and loss of native species. Changes in temperature and precipitation affect the composition and diversity of native animals and plants through altering their breeding patterns, water and food supply, and habitat availability.[149] In a changing climate, populations of some pests such as red fire ants and rodents, better adapted to a warmer climate, are projected to increase.[437,438] Grassland and plains birds, already besieged by habitat fragmentation, could experience significant shifts and reductions in their ranges.[439]

Urban sprawl, agriculture, and ranching practices already threaten the Great Plains' distinctive wetlands. Many of these are home to endangered and iconic species. In particular, prairie wetland ecosystems provide crucial habitat for migratory waterfowl and shorebirds.

Mallard ducks are one of the many species that inhabit the playa lakes, also known as prairie potholes.

Ongoing shifts in the region's population from rural areas to urban centers will interact with a changing climate, resulting in a variety of consequences.

Inhabitants of the Great Plains include a rising number of urban dwellers, a long tradition of rural communities, and extensive Native American

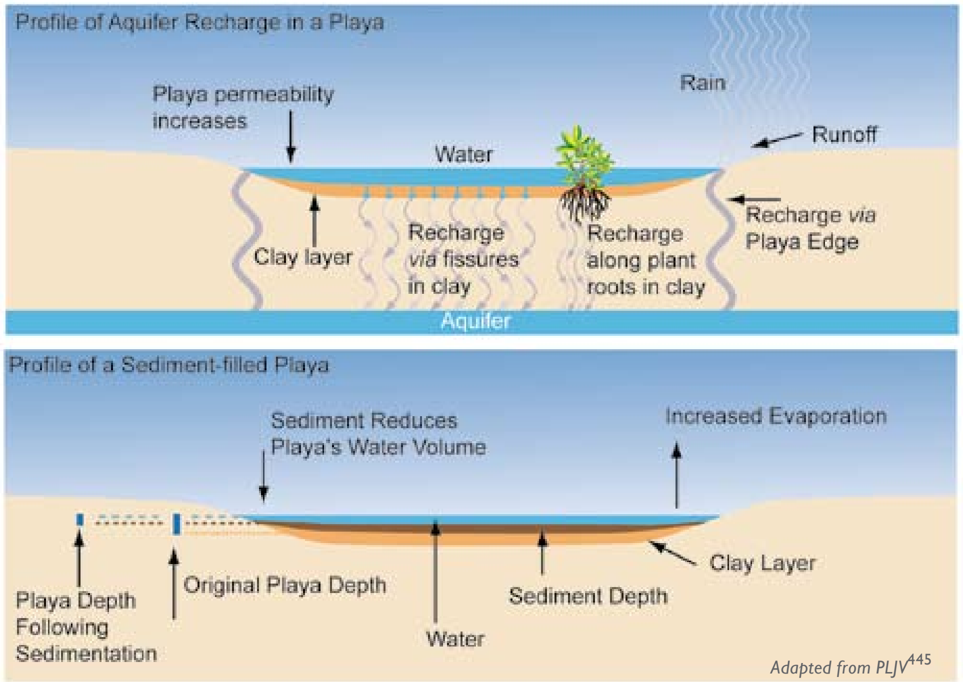
Playa Lakes and Prairie Potholes

Shallow ephemeral lakes dot the Great Plains, anomalies of water in the arid landscape. In the north they are known as prairie potholes; in the south, playa lakes. These lakes create unique microclimates that support diverse wildlife and plant communities. A playa can lie with little or no water for long periods, or have several wet/dry cycles each year. When it rains, what appeared to be only a few clumps of short, dry grasses just a few days earlier suddenly teems with frogs, toads, clam shrimp, and aquatic plants.

Playa lakes in west Texas fill up after a heavy spring rain.

The playas provide a perfect home for migrating birds to feed, mate, and raise their young. Millions of shorebirds and waterfowl, including Canada geese, mallard ducks, and Sandhill cranes, depend on the playas for their breeding grounds. From the prairie potholes of North Dakota to the playa lakes of West Texas, the abundance and diversity of native bird species directly depends on these lakes.[440,441]

Despite their small size, playa lakes and prairie potholes also play a critical role in supplying water to the Great Plains. The contribution of the playa lakes to this sensitively balanced ecosystem needs to be monitored and maintained in order to avoid unforeseen impacts on our natural resources. Before cultivation, water from these lakes was the primary source of recharge to the High Plains aquifer.[442] But many playas are disappearing and others are threatened by growing urban populations, extensive agriculture, and other filling and tilling practices.[443] In recent years, agricultural demands have drawn down the playas to irrigate crops. Agricultural waste and fertilizer residues drain into playas, decreasing the quality of the water, or clogging them so the water cannot trickle down to refill the aquifer. Climate change is expected to add to these stresses, with increasing temperatures and changing rainfall patterns altering rates of evaporation, recharge, and runoff to the playa lake systems.[444]



Adapted from PLJV[445]

populations. Although farming and ranching remain primary uses of the land – taking up much of the region's geographical area – growing cities provide housing and jobs for more than two-thirds of the population. For everyone on the Great Plains, though, a changing climate and a limited water supply are likely to challenge their ability to thrive, leading to conflicting interests in the allocation of increasingly scarce water resources.[313,433]

Native American communities

The Great Plains region is home to 65 Native American tribes. Native populations on rural tribal lands have limited capacities to respond to climate change.[313] Many reservations already face severe problems with water quantity and quality – problems likely to be exacerbated by climate change and other human-induced stresses.

Rural communities

As young adults move out of small, rural communities, the towns are increasingly populated by a vulnerable demographic of very old and very young people, placing them more at risk for health issues than urban communities. Combined effects of changing demographics and climate are likely to make it more difficult to supply adequate and efficient public health services and educational opportunities to rural areas. Climate-driven shifts in optimal crop types and increased risk of drought, pests, and extreme events will add more economic stress and tension to traditional communities.[430,433]

Urban populations

Although the Great Plains is not yet known for large cities, many mid-sized towns throughout the region are growing rapidly. One in four of the most rapidly growing cities in the nation is located in the Great Plains[446] (see *Society* sector). Most of these growing centers can be found in the southern parts of the region, where water resources are already seriously constrained. Urban populations, particularly the young, elderly, and economically disadvantaged, may also be disproportionately affected by heat.[447]

New opportunities

There is growing recognition that the enormous wind power potential of the Great Plains could provide new avenues for future employment and land use. Texas already produces the most wind power of any state. Wind energy production is also prominent in Oklahoma. North and South Dakota have rich wind potential.[191]

As climate change creates new environmental conditions, effective adaptation strategies become increasingly essential to ecological and socioeconomic survival. A great deal of the Great Plains' adaptation potential might be realized through agriculture. For example, plant species that mature earlier and are more resistant to disease and pests are more likely to thrive under warmer conditions.

Other emerging adaptation strategies include dynamic cropping systems and increased crop diversity. In particular, mixed cropping-livestock systems maximize available resources while minimizing the need for external inputs such as irrigation that draws down precious water supplies.[436] In many parts of the region, diverse cropping systems and improved water use efficiency will be key to sustaining crop and rangeland systems.[448] Reduced water supplies might cause some farmers to alter the intensive cropping systems currently in use.[193,219]

Adaptation: **Agricultural Practices to Reduce Water Loss and Soil Erosion**

Conservation of water is critical to efficient crop production in areas where water can be scarce. Following the Dust Bowl in the 1930s, Great Plains farmers implemented a number of improved farming practices to increase the effectiveness of rainfall capture and retention in the soil and protect the soil against water and wind erosion. Examples include rotating crops, retaining crop residues, increasing vegetative cover, and altering plowing techniques.

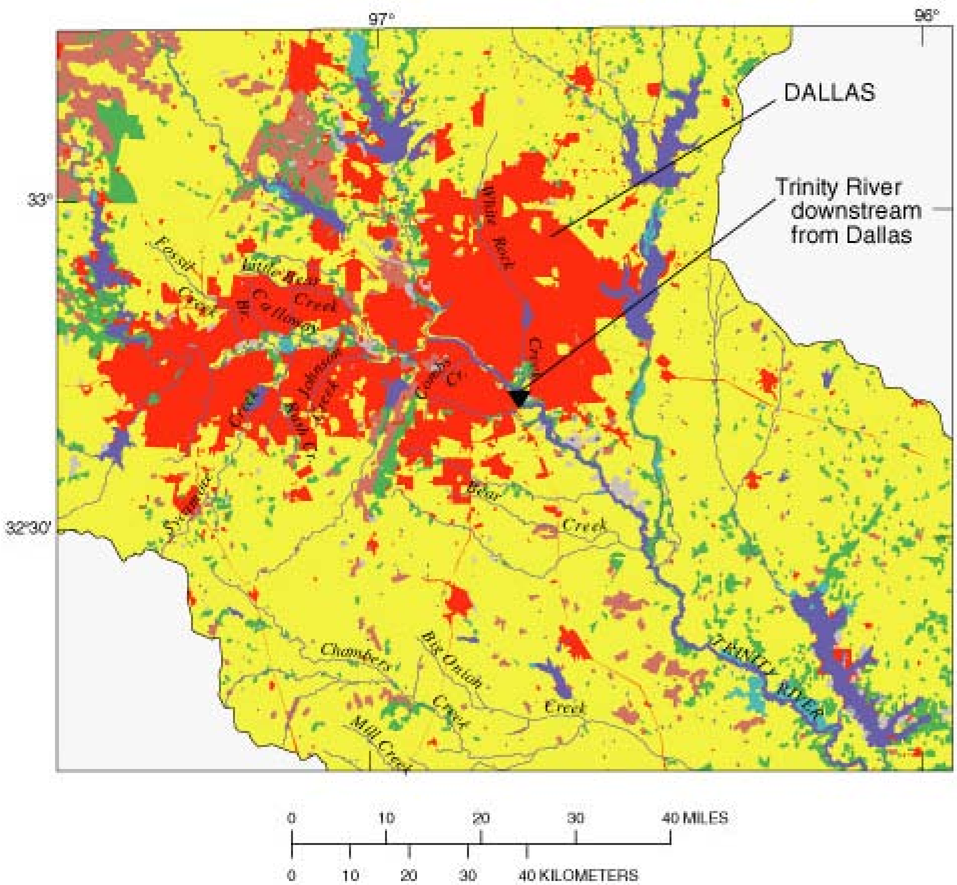
With observed and projected increases in summer temperatures and in the frequency and intensity of heavy downpours, it will become even more important to protect against increasing loss of water and soil. Across the upper Great Plains, where strong storms are projected to occur more frequently, producers are being encouraged to increase the amount of crop residue left on the soil or to plant cover crops in the fall to protect the soil in the spring before crops are planted.

Across the southern Great Plains, some farmers are returning to dryland farming rather than relying on irrigation for their crops. Preserving crop residue helps the soil absorb more moisture from rain and eases the burden on already-stressed groundwater. These efforts have been promoted by the U.S. Department of Agriculture through research and extension efforts such as Kansas State University's Center for Sustainable Agriculture and Alternative Crops.

USGS science for a changing world

Fish-Community Changes Reflect Water-Quality Improvements in the Trinity River Downstream From Dallas

| Contents | Quality of Ground Water |



The Trinity River downstream from Dallas data-collection site.

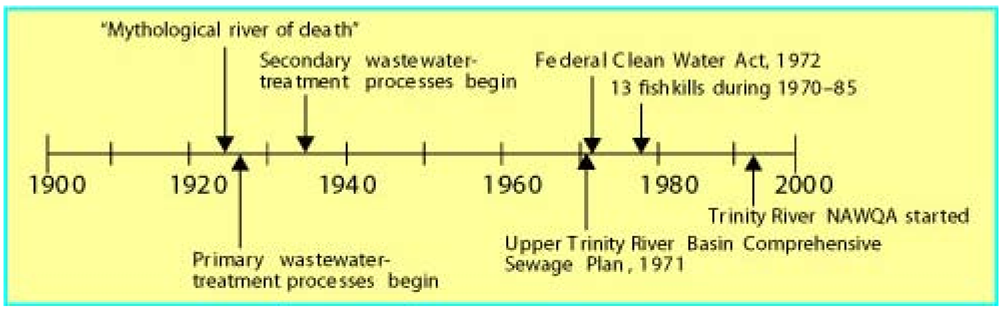
In 1925, the Trinity River in the Dallas-Fort Worth area was characterized by the Texas Department of Health as a "mythological river of death." With a rapid expansion of industry and population and only primary wastewater treatment beginning in the late 1920s and secondary treatment in the mid-1930s, water-quality conditions in the area were poor. They did not substantially improve until State and Federal pollution control laws, like the Federal Clean Water Act of 1972, stimulated efforts to address degraded water-quality conditions. The Upper Trinity River Basin Comprehensive Sewage Plan of 1971 resulted in the construction of large, regional wastewater-treatment plants, elimination of many small, industrial and municipal wastewater-treatment plants, and the upgrading of existing wastewater-treatment plants.

During 1970-85, 13 fishkills were documented in the Trinity River from a reach just downstream from Dallas to Lake Livingston in the lower part of the Trinity River Basin. The magnitude and frequency of the fishkills resulted in a depleted fish community, particularly in the reach of the Trinity River immediately downstream from Dallas. An estimated 1.04 million fish died in these 13 kills. Twelve of the 13 fishkills were associated with minor flooding on the Trinity River from rainfall in the Dallas-Fort Worth metropolitan area. According to the Texas Parks and Wildlife Department (TPWD), the probable cause of the kills was the resuspension of bottom sediments and associated organic material during floods that caused an increase in biochemical oxygen demand and a corresponding rapid drop in dissolved oxygen (Davis, 1987). Ironically, improvements in water quality during the 1970s set the stage for the fishkills by allowing appreciable fish populations to live in this reach of the Trinity River.

During 1970-85, more than 1 million fish were killed by water pollution in the Trinity River downstream from Dallas.

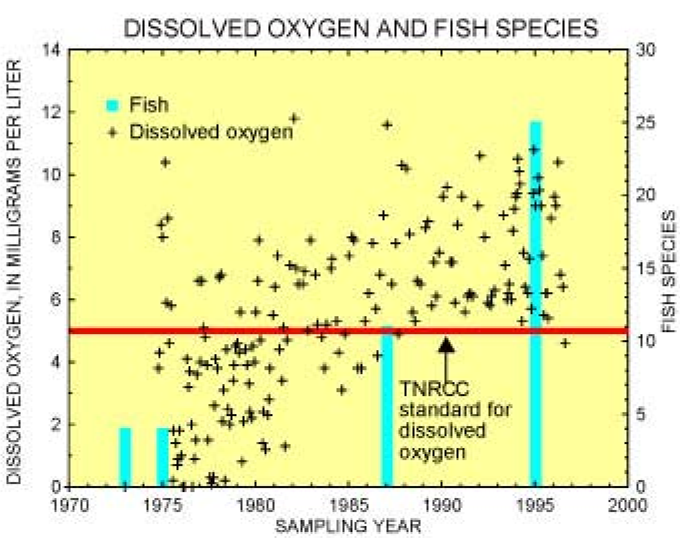
How Has the Water Quality Improved?

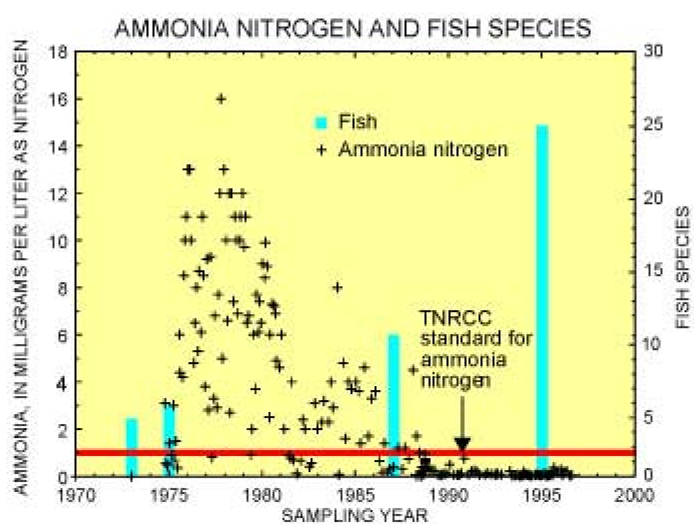
Dissolved oxygen, measured as milligrams of oxygen per liter of water, has increased from lows of near zero in the early 1970s to highs of more than 10 milligrams per liter in 1996. Notable improvement in dissolved oxygen concentrations in the Trinity River downstream from Dallas began in the late 1970s and continued through the 1980s and into the 1990s. Dissolved oxygen was consistently recorded above the TNRCC (Texas Natural Resource Conservation Commission, 1996) dissolved oxygen criterion for the support of aquatic life (5.0 milligrams per liter) beginning in the late 1980s. The improvement in dissolved oxygen concentrations is attributable to improvements in wastewater-treatment practices and the corresponding reduction in the discharge of oxygen-demanding materials from wastewater-treatment plants and industry.



A timeline of change for the Trinity River downstream from Dallas.

Advanced wastewater-treatment processes that include nitrification (conversion of ammonia nitrogen to nitrate) have been implemented at the large wastewater-treatment plants that discharge into the Trinity River in the Dallas-Fort Worth area. Ammonia consumes oxygen when it is converted to nitrate, and large concentrations of ammonia are toxic to fish and other aquatic organisms. Ammonia levels in the Trinity River downstream from Dallas exceeded the TNRCC criterion for dissolved ammonia in freshwater streams and reservoirs (1.0 milligram per liter) consistently until the late 1980s. Since then, the nitrification process used in wastewater-treatment plants has reduced the amount of ammonia nitrogen that is discharged to the river.

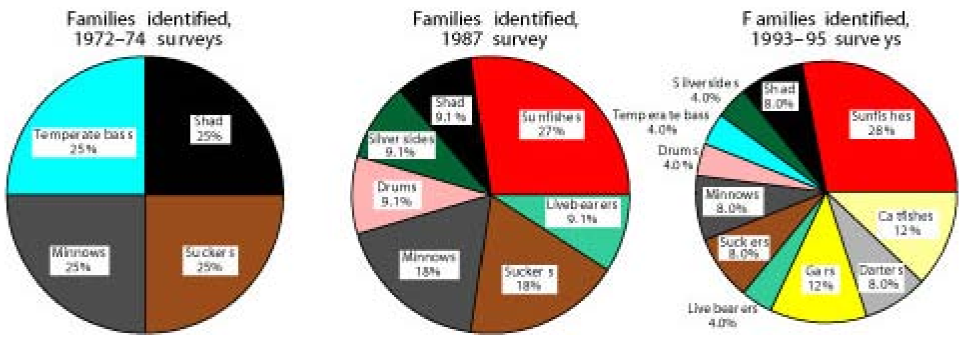




Fish species have increased as water quality improved in the Trinity River downstream from Dallas.

How Has the Fish Community Changed as a Result?

The fish community in the Trinity River immediately downstream from Dallas was almost nonexistent in the early 1970s (Texas Parks and Wildlife Department, 1974). Only four species of fish were collected by the TPWD during 1972-74—smallmouth buffalo, gizzard shad, common carp, and yellow bass. Four of the six surveys yielded no fish from this reach of the river. Two of the species, gizzard shad and common carp, generally are classified as tolerant taxa and could be expected to tolerate the water-quality conditions in this reach in the 1970s.



In slightly more than two decades, the fish community in a reach of the Trinity River downstream from Dallas has markedly improved. Improvement is most evident in the number of fish caught and the number of species, including those that are not tolerant of polluted water.

The TPWD collected 11 species of fish from this reach in 1987. Although the 1987 survey yielded more species than the 1972-74 surveys, the TPWD still considered the species richness low and attributed the condition to the fishes' exposure to ammonia nitrogen and heavy trace elements introduced from the upstream wastewater-treatment plants (Davis, 1991).

The USGS conducted fish-community surveys on the reach at Trinity River downstream from Dallas during 1993-95. The methods used by the USGS—seining, boat electrofishing, and gill netting—are identical to the methods used by the TPWD in 1987. A cumulative total of 25 species of fish were collected in this reach during the 3-year period. Several game species were collected including largemouth bass, white crappie, and white bass. None of these game species were collected in the reach during the 1972-74 or 1987 surveys. Two darter species, bigscale logperch and slough darter, also were collected. The presence of these indigenous species suggests a return of this reach to a more natural condition. Other species characteristic of warm-water southeastern streams—alligator, spotted, and longnose gars and flathead, blue, and channel catfish—frequently were collected during the USGS surveys of 1993-95. None of these gar or catfish species were reported in the reach downstream from Dallas in the 1972-74 or 1987 TPWD surveys. The change since 1972-74 is a likely consequence of improvements in water quality, particularly improvements in the quality of discharges from wastewater-treatment plants in the Dallas-Fort Worth area.

Fish surveys during 1993-95 indicate that the Trinity River downstream from Dallas is typical of a large stream in the region.

Catching fish with a backpack electrofishing device.

White bass being measured and examined.

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License Renewal

- Overview
- Process
- Regulations
- Guidance
- Public Involvement
- Commission Papers
- Status
- Introduction

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Status of License Renewal Applications and Industry Activities

On this page:

Plant Applications for License Renewal

Completed Applications:

(includes Application, Review Schedule, Supplemental Environmental Impact Statement, and Safety Evaluation Report)

- Calvert Cliffs, Units 1 and 2
- Oconee Nuclear Station, Units 1, 2 and 3
- Arkansas Nuclear One, Unit 1
- Edwin I. Hatch Nuclear Plant, Units 1 and 2
- Turkey Point Nuclear Plant, Units 3 and 4
- North Anna, Units 1 and 2, and Surry, Units 1 and 2
- Peach Bottom, Units 2 and 3
- St. Lucie, Units 1 and 2
- Fort Calhoun Station, Unit 1
- McGuire, Units 1 and 2, and Catawba, Units 1 and 2
- H.B. Robinson Nuclear Plant, Unit 2
- R.E. Ginna Nuclear Power Plant, Unit 1
- V.C. Summer Nuclear Station, Unit 1
- Dresden, Units 2 and 3, and Quad Cities, Units 1 and 2
- Farley, Units 1 and 2
- Arkansas Nuclear One, Unit 2
- D.C. Cook, Units 1 and 2
- Millstone, Units 2 and 3
- Point Beach, Units 1 and 2
- Browns Ferry, Units 1, 2, and 3
- Brunswick, Units 1 and 2
- Nine Mile Point, Units 1 and 2
- Monticello
- Palisades
- James A. FitzPatrick
- Wolf Creek, Unit 1
- Harris, Unit 1
- Oyster Creek
- Vogtle, Units 1 and 2
- Three Mile Island, Unit 1
- Beaver Valley, Units 1 and 2
- Susquehanna, Units 1 and 2

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Applications Currently Under Review:

- Pilgrim 1, Unit 1 - Application received January 27, 2006
- Vermont Yankee - Application received January 27, 2006
- Indian Point, Units 2 and 3 - Application received April 30, 2007
- Prairie Island, Units 1 and 2 - Application received April 15, 2008
- Kewaunee Power Station - Application received August 14, 2008
- Cooper Nuclear Station - Application received September 30, 2008
- Duane Arnold Energy Center - Application received October 1, 2008
- Palo Verde, Units 1, 2, and 3 - Application received December 15, 2008
- Crystal River, Unit 3 - Application received December 18, 2008
- Hope Creek - Application received August 18, 2009
- Salem, Units 1 and 2 - Application received August 18, 2009
- Diablo Canyon, Units 1 and 2 - Application received November 24, 2009
- Columbia Generating Station - Application received January 20, 2010

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Some links on this page are to documents in our Agencywide Documents Access and Management System (ADAMS), and others are to documents in Adobe Portable Document Format (PDF). ADAMS documents are provided in either PDF or Tagged Image File Format (TIFF). To obtain free viewers for displaying these formats, see our Plugins, Viewers, and Other Tools page. If you have questions about search techniques or problems with viewing or printing documents from ADAMS, please contact the Public Document Room staff.

Future Submittals of Applications:

Fiscal Year	No.	Renewal Application	Applicant	Letter of Intent (ADAMS Accession No.)	Submission Date
2010	1	Seabrook Station, Unit 1	FPL Energy Seabrook, LLC	ML073381282	Apr. to June 2010
	2	Davis-Besse Nuclear Power Station, Unit 1	FirstEnergy Nuclear Operating Company	ML062290261	Aug. 2010
2011	1	South Texas Project, Unit 1 and Unit 2	STP Nuclear Operating Company	ML081770299	Oct. to Dec. 2010
	2	Grand Gulf Nuclear Station, Unit 1	Entergy Nuclear, Inc.	ML092450109	July 2011
	3	Limerick Generating Station, Unit 1 and Unit 2	Exelon Generation Company, LLC	ML091210103	Sept. 2011
2012	1	Callaway Plant, Unit 1	AmerenUE	ML083370203	Oct. to Dec. 2011
2013	1	Strategic Teaming and Resource Sharing (STARS) No. 7	Un-named	ML080590377	Oct. to Dec. 2012
	2	Waterford Steam Electric Station, Unit 3	Entergy Nuclear, Inc.	ML092450109	Jan. 2013
	3	Sequoyah Nuclear Plant, Unit 1 and Unit 2	Tennessee Valley Authority	ML092220377	Apr. to June 2013
	4	Strategic Teaming and Resource Sharing (STARS) No. 6	Un-named	ML062550111	July to Sept. 2013
	5	Un-named	Exelon Generation Company, LLC	ML091210103	July 2013
	6	Perry Nuclear Power Plant, Unit 1	FirstEnergy Nuclear Operating Company	ML062290261	Aug. 2013

2015	1	River Bend Station, Unit 1	Entergy Nuclear, Inc.	ML092450109	Jan. 2015
	2	Un-named	Exelon Generation Company, LLC	ML091210103	July 2015
2017	1	Un-named	Exelon Generation Company, LLC	ML091210103	Apr. 2017

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Owners' Groups

Babcock & Wilcox -- The Babcock & Wilcox Owners Group, representing five operating B&W plants, has formulated a generic license renewal program. The B&W Owners Group has submitted generic license renewal reports on the reactor coolant system piping, the pressurizer, the reactor pressure vessel, and reactor vessel internals.

Westinghouse -- The Westinghouse Owners Group also has programs for license renewal and has submitted technical reports on the aging management activities for the reactor coolant system supports, the pressurizer, the Class I piping, the containment structure, and the reactor vessel internals.

General Electric -- The Boiling Water Reactor Owners Group submitted a generic technical report on the containment structure and is currently concentrating their efforts on reports related to the vessel internals program.

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Industry Activities

Nuclear Energy Institute (NEI) -- Industry representatives also participate in working groups and technical committees, coordinated by the Nuclear Energy Institute, to address generic technical and process issues, and to develop additional guidance related to scoping and aging management programs. The NRC has established a formal feedback process by which the resolution of the generic renewal issues and lessons learned during the review of the initial renewal applications is documented and included in revisions to the implementation guidance. These activities are expected to improve the efficiency and effectiveness of future license renewal reviews.

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Related Information

Slides for Vermont Yankee and Pilgrim License Renewal Application.

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Bellville Operations Division

Overview

U. S. Steel Tubular Products, Inc.'s Bellville Operations Division produces high-quality line pipe and oil country tubular goods (OCTG), particularly high-strength production tubing.

Bellville Operations Division:

- Uses raw material that is continuous cast, fully killed steel with inclusion shape control
- Provides full body normalize
- Provides full-length ultrasonic inspection of weld seams
- Performs full body inspection using eddy current

Contact Information

U. S. Steel Tubular Products, Inc.
Bellville Operations Division
141 Miller Road
Bellville, TX 77418
979-865-9111 or 800-884-8823

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Physiography of Texas

Geologists study the natural scenery of Texas and sort its variations into distinctive physiographic provinces. Each province or landscape reflects a unified geological history of depositional and erosional processes. Each physiographic province is distinguished by characteristic geologic structure, rock and soil types, vegetation, and climate. The elevations and shapes of its landforms contrast significantly with those of landforms in adjacent regions. The ***Physiographic Map of Texas*** displays seven physiographic provinces and their principal subdivisions; the accompanying table describes their major physical differences. The following descriptions selectively emphasize those characteristics that distinguish provinces and their subdivisions.

Gulf Coastal Plains. The Gulf Coastal Plains include three subprovinces named the Coastal Prairies, the Interior Coastal Plains, and the Blackland Prairies. The Coastal Prairies begin at the Gulf of Mexico shoreline. Young deltaic sands, silts, and clays erode to nearly flat grasslands that form almost imperceptible slopes to the southeast. Trees are uncommon except locally along streams and in Oak mottes, growing on coarser underlying sediments of ancient streams. Minor steeper slopes, from 1 foot to as much as 9 feet high, result from subsidence of deltaic sediments along faults. Between Corpus Christi and Brownsville, broad sand sheets pocked by low dunes and blowouts forming ponds dominate the landscape.

The Interior Coastal Plains comprise alternating belts of resistant uncemented sands among weaker shales that erode into long, sandy ridges. At least two major down-to-the coast fault systems trend nearly parallel to the coastline. Clusters of faults also concentrate over salt domes in East Texas. That region is characterized by pine and hardwood forests and numerous permanent streams. West and south, tree density continuously declines, pines disappear in Central Texas, and chaparral brush and sparse grasses dominate between San Antonio and Laredo.

On the Blackland Prairies of the innermost Gulf Coastal Plains, chalks and marls weather to deep, black, fertile clay soils, in contrast with the thin red and tan sandy and clay soils of the Interior Gulf Coastal Plains. The blacklands have a gentle undulating surface, cleared of most natural vegetation and cultivated for crops.

From sea level at the Gulf of Mexico, the elevation of the Gulf Coastal Plains increases northward and westward. In the Austin San Antonio area, the average elevation is about 800 feet. South of Del Rio, the western end of the Gulf Coastal Plains has an elevation of about 1,000 feet.

Grand Prairie. The eastern Grand Prairie developed on limestones; weathering and erosion have left thin rocky soils. North and west of Fort Worth, the plateaulike surface is well exposed, and numerous streams dissect land that is mostly flat or that gently slopes southeastward. There, silver bluestem-Texas wintergrass grassland is the flora. Primarily sandstones underlie the western margin of the Grand Prairie, where post oak woods form the Western Cross Timbers.

Edwards Plateau. The Balcones Escarpment, superposed on a curved band of major normal faults, bounds the eastern and southern Edwards Plateau. Its principal area includes the Hill Country and a broad plateau. Stream erosion of the fault escarpment sculpts the Hill Country from Waco to Del Rio. The Edwards Plateau is capped by hard Cretaceous limestones. Local streams entrench the plateau as much as 1,800 feet in 15 miles. The upper drainages of streams are waterless draws that open into box canyons where springs provide permanently flowing water. Sinkholes commonly dot the limestone terrane and connect with a network of caverns. Alternating hard and soft marly limestones form a stairstep topography in the central interior of the province.

The Edwards Plateau includes the Stockton Plateau, mesalike land that is the highest part of this subdivision. With westward decreasing rainfall, the vegetation grades from mesquite juniper brush westward into creosote bush tarbush shrubs.

The Pecos River erodes a canyon as deep as 1,000 feet between the Edwards and Stockton Plateaus. Its side streams become draws forming narrow blind canyons with nearly vertical walls. The Pecos Canyons include the major river and its side streams. Vegetation is sparse, even near springs and streams.

Central Texas Uplift. The most characteristic feature of this province is a central basin having a rolling floor studded with rounded granite hills 400 to 600 feet high. Enchanted Rock State Park is typical of this terrain. Rocks forming both basin floor and hills are among the oldest in Texas. A rim of resistant lower Paleozoic formations (see the ***Geology of Texas*** map) surrounds the basin. Beyond the Paleozoic rim is a second ridge formed of limestones like those of the Edwards Plateau. Central live oak mesquite parks are surrounded by live oak ashe juniper parks.

North-Central Plains. An erosional surface that developed on upper Paleozoic formations forms the North-Central Plains. Where shale bedrock prevails, meandering rivers traverse stretches of local prairie. In areas of harder bedrock, hills and rolling plains dominate. Local areas of hard sandstones and limestones cap steep slopes severely dissected near rivers. Lengthy dip slopes of strongly fractured limestones display extensive rectangular patterns. Western rocks and soils are oxidized red or gray where gypsum dominates, whereas eastern rocks and soils weather tan to buff. Live oak ashe juniper parks grade westward into mesquite lotebush brush.

High Plains. The High Plains of Texas form a nearly flat plateau with an average elevation approximating 3,000 feet. Extensive stream-laid sand and gravel deposits, which contain the Ogallala aquifer, underlie the plains. Windblown sands and silts form thick, rich soils and caliche locally. Havard shin oak mesquite brush dominates the silty soils, whereas sandsage Havard shin oak brush occupies the sand sheets. Numerous playa lakes scatter randomly over the treeless plains. The eastern boundary is a westward-retreating escarpment capped by a hard caliche. Headwaters of major rivers deeply notch the caprock, as exemplified by Palo Duro Canyon and Caprock Canyons State Parks.

On the High Plains, widespread small, intermittent streams dominate the drainage. The Canadian River cuts across the province, creating the Canadian Breaks and separating the Central High Plains from the Southern High Plains. Pecos River drainage erodes the west-facing escarpment of the Southern High Plains, which terminates against the Edwards Plateau on the south.

Basin and Range. The Basin and Range province contains eight mountain peaks that are higher than 8,000 feet. At 8,749 feet, Guadalupe Peak is the highest point in Texas. Mountain ranges generally trend nearly north-south and rise abruptly from barren rocky plains.

Plateaus in which the rocks are nearly horizontal and less deformed commonly flank the mountains. Cores of strongly folded and faulted sedimentary and volcanic rocks or of granite rocks compose the interiors of mountain ranges. Volcanic rocks form many peaks. Large flows of volcanic ash and thick deposits of volcanic debris flank the slopes of most former volcanoes. Ancient volcanic activity of the Texas Basin and Range province was mostly explosive in nature, like Mount Saint Helens. Volcanoes that poured successive lava flows are uncommon. Eroded craters, where the cores of volcanoes collapsed and subsided, are abundant.

Gray oak pinyon pine alligator juniper parks drape the highest elevations. Creosote bush and lechuguilla shrubs sparsely populate plateaus and intermediate elevations. Tobosa black grama grassland occupies the low basins.

The Physiographic Map of Texas is a useful guide to appreciate statewide travel. Texas abounds with vistas of mountains, plateaus, plains, hills, and valleys in which many rock types and geologic structures are exposed. A variety of vegetation grows, depending on local climate.

Text by E. G. Wermund

The **Bureau of Economic Geology,** established in 1909, is a research entity of The University of Texas at Austin and also functions as the State Geological Survey The Bureau conducts basic and applied research projects in energy and mineral resources, coastal and environmental studies, land resources, and geologic mapping. Reports and maps published by the Bureau are available for a nominal price. A list of publications is available on request, or visit:

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Lake Ralph Hall

Planning today for the water we'll need tomorrow.

In 1989, communities of the Denton County area requested the legislature to create Upper Trinity Regional Water District - - with a priority mission to develop a regional strategy for water supply. Working with Members and Customers, Upper Trinity is planning today for the water this region will need tomorrow. By state law, we must plan ahead for at least 50 years.

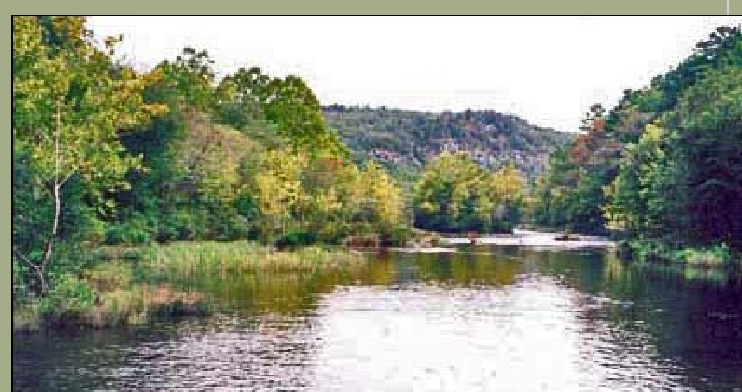
Because ground water (from wells) is so limited in this region, the most reliable water for the future is from surface water sources (from lakes). Therefore, to provide a reliable, secure and adequate water supply for this region, Upper Trinity is developing a comprehensive and diversified portfolio of water supply sources. Present supplies are adequate for about 25 years, and additional water sources are needed to extend the supply to 50 years.

Upper Trinity Regional Water District's Diversified Water Portfolio

? Local water in Lewisville Lake and Ray Roberts Lake
? Chapman (Cooper) Lake in northeast Texas
? Proposed Lake Ralph Hall in Fannin County
? Proposed reuse of water from water reclamation plants
? Possible additional water from the Sulphur River Basin
? Proposed purchase of additional water from City of Dallas

Recognizing that it takes 25 to 35 years to develop a lake, additional sources must be identified today so they can be developed in time for tomorrow. Proposed Lake Ralph Hall represents a strategic opportunity for an investment in the future economy of this region - - an investment for our families.

Before : *Erosion Threatens Environment*



After : *Water for the People*

With Vision and courage, we plan.
With cooperation and committment, we serve.

UPPER TRINITY
REGIONAL WATER DISTRICT

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Texas Renewable Energy Assessment Summary

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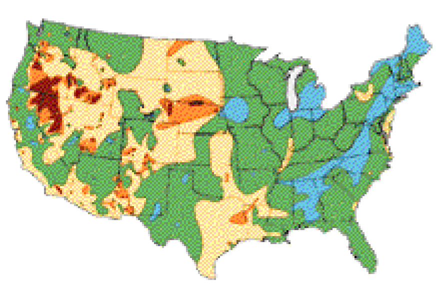
GEOTHERMAL

Geothermal energy derives from the immense thermal reservoir of the earth's interior. Heat from molten rock (magma) beneath the earth's crust or from natural radioactive decay transfers to rock and water closer to the surface. In certain regions of the earth, the hot waters are close enough to the surface to be commercially exploited in heating applications, or, in the case of high-grade steam reserves, in electrical power generation.

One question that commonly arises regarding geothermal energy is whether or not it is a renewable resource. The answer hinges on how the resource is developed. Certainly the heat within the earth, like the sun, is limitless compared to human activity. However, the waters that are tapped in geothermal development are finite. Hydrothermal (hot water) aquifers will be diminished whenever water is withdrawn faster than it is recharged. Overexploitation at some facilities in California, for example, resulted in a lower than expected output. If water is reinjected into the field after extracting heat (as is done in some locations), then the resource may be said to be truly renewable. Otherwise, it is simply mined, much as a petroleum reserve.

Areas with significant geothermal resource occur where the earth's crust is relatively thin, such as along the boundaries of tectonic plates. Geysers, hot springs, volcanoes, and seismic activity, all of which are noticeably absent in Texas, mark such regions. In the U.S., the best geothermal resources occur along the Pacific rim (California to Alaska) and in Hawaii (see Figure 13). California has the largest geothermal electric facilities in the nation, with about 1100 MWe, most concentrated at the Geysers steam field in the northern part of that state.



GEOTHERMAL GRADIENT (degrees

C/km)					
0-14	15-29	30-44	45-59	60+	

FIGURE 13. Geothermal Gradient Contour Map of the United States.

The increase in temperature with depth below the ground is highest in areas with volcanic and seismic activity. This map indicates Hot Dry Rock potential.

A significant portion of the energy consumed in the United States requires relatively low temperatures. Energy needed for space and water heating, fish farming and greenhouse heating, enhanced oil recovery, and desalinization can take advantage of low temperature hydrothermal resources if such resources are present where the energy is consumed.

The Texas Resource

Texas does not possess any easily accessible field with the high temperatures required for electric power generation. It does, however, possess some low-temperature hydrothermal reserves that have seen limited use. As shown in Figure 14, these resources occur mainly in two bands, one that cuts a swath through the central part of the state, and a second that borders the Rio Grande in the Trans-Pecos. Temperatures in the Central Texas hydrothermal aquifers range from about 90° to 160°F at depths from 500 to 5,000 feet. Historically the waters have seen some application in spas and therapeutic baths. Where waters are potable, a number of smaller communities have tapped them for their municipal supply, without making use of the heat. A recent project in Marlin, however, employed geohermal well water to heat a local hospital. In the Trans-Pecos, thermal waters have likewise supplied resort baths, with scant need for more extensive development owing to the region's remoteness.

TEXAS GEOTHERMAL AREAS, CHARACTERS AND USES			
	HYDROTHERMAL	**GEOPRESSURE**	**HOT DRY ROCK**
AREAS	Known	Known	Known
	Potential Hydrothermal or Geopressure Source		
CHARACTERISTICS	• 90 - 160 °F Water (500-5,000 ft. deep) • In some cases Water is Potable	• 300 - 450 °F Brine (>13,000 ft. deep) • High Pressure • Dissolved Methane	• Gradient > 45 °C/km • Little or No Water

USES	• Space Heating • Fish Farming • Desalinization • Resort Spas	• Heating • Enhanced Oil Recovery • Electricity	• Heating • Electricity

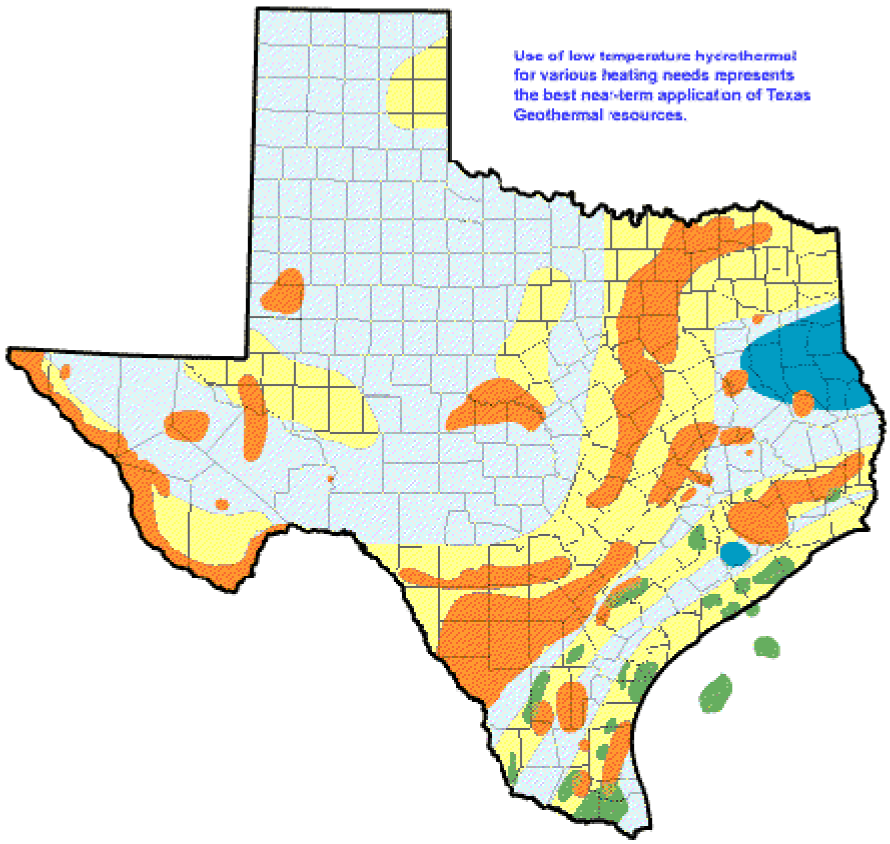


FIGURE 14. Texas Geothermal Resource Areas.
Hydrothermal, geopressured, and hot dry rock resource areas are identified; characteristics and uses for each are listed in the legend.

In addition to the state's low-temperature hydrothermal resource, large zones of hot, highly pressurized fluids occur in deep strata under the Gulf Coast. This so-called "geopressured-geothermal" resource was studied extensively in the 1970's and 1980's and a test well was operated by the Department of Energy at Pleasant Bayou near Houston. Typically, geopressured zones are at depths on the order of 15,000 feet and the fluid itself is a hot (about 300 deg. F), high-pressure brine with methane dissolved in it. Interest in the resource is probably driven as much by the potential methane recovery as by its geothermal character. To date, development has not proven economical. Hot brine, however, may someday be used in enhanced oil recovery schemes. Since the resource is not renewable, it must be mined to be used.

A final, long-term geothermal energy prospect is the extraction of heat from zones of "hot dry rock" (HDR). In the envisioned HDR facility, high-pressure water injected underground at one point is collected at a distance well after it has been heated by passing through fractured, hot rock. The scheme is presently in its infancy. One study suggested that Texas has moderately good resource in the eastern part of the state (see Figure 13).

Value of the Texas Resource

Texas does not have the sort of readily accessible, high-temperature hydrothermal resource that can be used to generate electricity. The resource in the central part of the state can, however, have an impact in low-temperature applications such as space heating or aquaculture. Several municipalities that presently introduce warm aquifer water in drinking supplies could capture beneficial heat with the addition of a heat exchanger. The geopressured-geothermal resource will become more attractive only in the context of higher energy prices. Hot dry rock's potential value is presently unknown.

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GAM Run 08-14mag

by Shirley C. Wade, P.G.
Texas Water Development Board
Groundwater Availability Modeling Section
(512) 463-3132
May 6, 2008

REQUESTOR:

Ms. Cheryl Maxwell of the Clearwater Underground Water Conservation District acting on behalf of Groundwater Management Area 8.

DESCRIPTION OF REQUEST:

In a letter dated December 26, 2007, Ms. Cheryl Maxwell provided the Texas Water Development Board (TWDB) with the desired future conditions for the Edwards (Balcones Fault Zone), Blossom, Brazos River Alluvium, Nacatoch, and Woodbine aquifers in Groundwater Management Area 8 and requested that TWDB estimate managed available groundwater values. This groundwater availability modeling run presents the managed available groundwater for the Woodbine Aquifer in Groundwater Management Area 8.

DESIRED FUTURE CONDITIONS:

Desired future conditions for the Woodbine Aquifer submitted to TWDB by the groundwater conservation districts in Groundwater Management Area 8:

- From estimated year 2000 conditions, the average drawdown should not exceed approximately 154 feet after 50 years in Collin County.
- From estimated year 2000 conditions, the average drawdown should not exceed approximately 0 feet after 50 years in Cooke County.
- From estimated year 2000 conditions, the average drawdown should not exceed approximately 112 feet after 50 years in Dallas County.
- From estimated year 2000 conditions, the average drawdown should not exceed approximately 16 feet after 50 years in Denton County.
- From estimated year 2000 conditions, the average drawdown should not exceed approximately 102 feet after 50 years in Ellis County.
- From estimated year 2000 conditions, the average drawdown should not exceed approximately 186 feet after 50 years in Fannin County.
- From estimated year 2000 conditions, the average drawdown should not exceed approximately 28 feet after 50 years in Grayson County.
- From estimated year 2000 conditions, the average drawdown should not exceed approximately 87 feet after 50 years in Hill County.
- From estimated year 2000 conditions, the average drawdown should not exceed approximately 353 feet after 50 years in Hunt County.

- From estimated year 2000 conditions, the average drawdown should not exceed approximately 4 feet after 50 years in Johnson County.
- From estimated year 2000 conditions, the average drawdown should not exceed approximately 211 feet after 50 years in Kaufman County.
- From estimated year 2000 conditions, the average drawdown should not exceed approximately 297 feet after 50 years in Lamar County.
- From estimated year 2000 conditions, the average drawdown should not exceed approximately 61 feet after 50 years in McLennan County.
- From estimated year 2000 conditions, the average drawdown should not exceed approximately 177 feet after 50 years in Navarro County.
- From estimated year 2000 conditions, the average drawdown should not exceed approximately 202 feet after 50 years in Red River County.
- From estimated year 2000 conditions, the average drawdown should not exceed approximately 241 feet after 50 years in Rockwall County.
- From estimated year 2000 conditions, the average drawdown should not exceed approximately 2 feet after 50 years in Tarrant County.

This information is summarized in Table 1.

Table 1. Summary of requested desired future conditions for the Woodbine Aquifer in Groundwater Management Area 8.

County	Average water level decrease (feet)
Collin	154
Cooke	0
Dallas	112
Denton	16
Ellis	102
Fannin	186
Grayson	28
Hill	87
Hunt	353
Johnson	4
Kaufman	211
Lamar	297
McLennan	61
Navarro	177
Red River	202
Rockwall	241
Tarrant	2

EXECUTIVE SUMMARY:

TWDB staff ran the groundwater availability model for the northern part of the Trinity Aquifer and the Woodbine Aquifer to determine the managed available groundwater based on the desired future conditions for the Woodbine Aquifer adopted by the groundwater conservation districts in Groundwater Management Area 8. The results are listed in Table 2:

METHODS:

This request is based on previous GAM run 07-30 (Wade, 2007). In that simulation, average streamflows and evapotranspiration rates were used for each year of the predictive simulation. Average recharge was used for the first forty-seven years of the simulation, followed by a three-year drought-of-record.

PARAMETERS AND ASSUMPTIONS:

The groundwater availability model for the northern part of the Trinity Aquifer was used for this model run. The parameters and assumptions for this model are described below:

- We used version 1.01 of the groundwater availability model for the northern part of the Trinity Aquifer for this run. See Bené and others (2004) for assumptions and limitations of the model.

- The model includes seven layers, representing the Woodbine Aquifer (Layer 1), the Washita and Fredericksburg Series (Layer 2), the Paluxy Formation (Layer 3), the Glen Rose Formation (Layer 4), the Hensell Formation (Layer 5), the Pearsall/Cow Creek/Hammett/Sligo formations (Layer 6), and the Hosston Formation (Layer 7). The Woodbine, Paluxy, Hensell, and Hosston layers are the main aquifers used in the region.

- The mean absolute error (a measure of the difference between simulated and actual water levels during model calibration) for the four main aquifers in the model (Woodbine, Paluxy, Hensell, and Hosston) for the calibration and verification time periods (1980 to 2000) ranged from approximately 37 to 75 feet. The root mean squared error was less than ten percent of the maximum change in water levels across the model (Bené and others, 2004).

- We used average annual recharge conditions based on climate data from 1980 to 1999 for the simulation. The last three years of the simulation used drought-of-record recharge conditions, which were defined as the years 1954 to 1956.

- The model uses the MODFLOW stream-routing package to simulate the interaction between the aquifer(s) and major intermittent streams flowing in the region. Flow both from the stream to the aquifer and from the aquifer to the stream is allowed, and the direction of flow is determined by the water levels in the aquifer and stream during each stress period in the simulation.

- Spatial and vertical pumpage distribution is described in GAM run 07-30 (Wade, 2007).

Table 2. Estimates of managed available groundwater for the Woodbine Aquifer by geographic subdivisions (See Figure 1).

Aquifer	Map Key	County	RWPA	River Basin	GCD	GMA	GeoArea	Year	MAG (Acre-feet per year)
Woodbine	39	Collin	C	Sabine	None	8	Collin	n/a	40
Woodbine	40	Collin	C	Trinity	None	8	Collin	n/a	2,469
Woodbine	47	Cooke	C	Red	None	8	Cooke	n/a	18
Woodbine	48	Cooke	C	Trinity	None	8	Cooke	n/a	136
Woodbine	50	Dallas	C	Trinity	None	8	Dallas	n/a	2,313
Woodbine	51	Delta	C	Sulphur	None	8	Delta	n/a	20
Woodbine	52	Denton	C	Trinity	None	8	Denton	n/a	4,126
Woodbine	55	Ellis	C	Trinity	None	8	Ellis	n/a	5,441
Woodbine	59	Fannin	C	Red	None	8	Fannin	n/a	2,676
Woodbine	60	Fannin	C	Sulphur	None	8	Fannin	n/a	21
Woodbine	61	Fannin	C	Trinity	None	8	Fannin	n/a	600
Woodbine	69	Grayson	C	Red	None	8	Grayson	n/a	6,590
Woodbine	70	Grayson	C	Trinity	None	8	Grayson	n/a	5,497
Woodbine	83	Hill	G	Brazos	None	8	Hill	n/a	1,249
Woodbine	82	Hill	G	Trinity	None	8	Hill	n/a	1,012
Woodbine	92	Hunt	D	Sabine	None	8	Hunt	n/a	1,867
Woodbine	91	Hunt	D	Sulphur	None	8	Hunt	n/a	849
Woodbine	93	Hunt	D	Trinity	None	8	Hunt	n/a	124
Woodbine	97	Johnson	G	Brazos	None	8	Johnson	n/a	141
Woodbine	96	Johnson	G	Trinity	None	8	Johnson	n/a	4,591
Woodbine	99	Kaufman	C	Sabine	None	8	Kaufman	n/a	0
Woodbine	100	Kaufman	C	Trinity	None	8	Kaufman	n/a	200
Woodbine	102	Lamar	D	Red	None	8	Lamar	n/a	1,910
Woodbine	103	Lamar	D	Sulphur	None	8	Lamar	n/a	1,734
Woodbine	111	Limestone	G	Brazos	None	8	Limestone	n/a	34

Aquifer	Map Key	County	RWPA	River Basin	GCD	GMA	GeoArea	Year	MAG (Acre-feet per year)
Woodbine	114	McLennan	G	Brazos	McLennan C.	8	McLennan	n/a	5
Woodbine	130	Navarro	C	Trinity	None	8	Navarro	n/a	300
Woodbine	137	Red River	D	Red	None	8	Red River	n/a	162
Woodbine	138	Red River	D	Sulphur	None	8	Red River	n/a	4
Woodbine	140	Rockwall	C	Sabine	None	8	Rockwall	n/a	0
Woodbine	141	Rockwall	C	Trinity	None	8	Rockwall	n/a	144
Woodbine	152	Tarrant	C	Trinity	N. Trinity	8	Tarrant	n/a	632

GCD = Groundwater conservation district.

GeoArea = Geographic areas defined by unique desired future conditions as specified by a groundwater management area.

GMA = Groundwater management area.

MAG = Managed available groundwater in units of acre-feet per year.

McLennan C. = McLennan County Groundwater Conservation District

N. Trinity = Northern Trinity Groundwater Conservation District

RWPA = Regional water planning area.

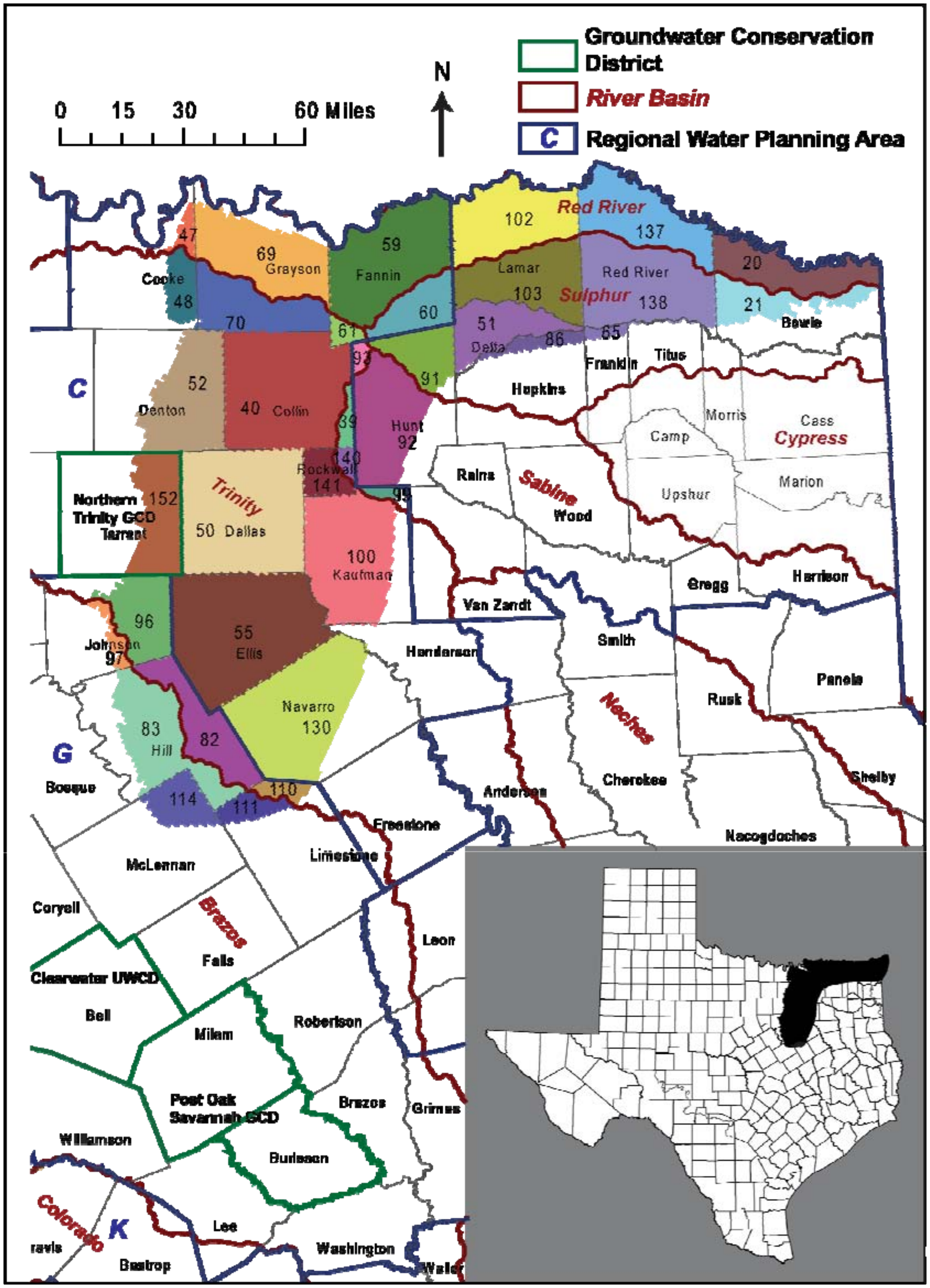

Figure 1. Geographic subdivisions of managed available groundwater for the Woodbine Aquifer. See Table 2 for descriptions of the geographic subdivisions.

RESULTS:

Water level declines in the Woodbine Aquifer for the counties in Groundwater Management Area 8 were verified to meet the desired future conditions developed by groundwater conservation districts in Groundwater Management Area 8. The results (Figure 1 and Table 2) show 44,905 acre-feet per year of managed available groundwater for the Woodbine Aquifer in Groundwater Management Area 8. Under the jurisdiction of the Northern Trinity Groundwater Conservation District, Tarrant County has 632 acre-feet per year of managed available groundwater in the Woodbine Aquifer. The remaining counties in Regional Planning Area C have 30,591 acre-feet per year of managed available groundwater. McLennan County Groundwater Conservation District has 5 acre-feet per year. The remaining counties in Regional Planning Area G have 7,027 acre-feet per year of managed available groundwater. The counties in Regional Planning Area D have 6,650 acre-feet per year of managed available groundwater.

Note that estimates of managed available groundwater are based on the best available scientific tools that can be used to evaluate managed available groundwater and that these estimates can be a function of assumptions made on the magnitude and distribution of pumping in the aquifer. Therefore, it is important for groundwater conservation districts to monitor whether or not they are achieving their desired future conditions and to work with the TWDB to refine managed available groundwater given the reality of how the aquifer responds to the actual magnitude and distribution of pumping now and in the future. In addition, any changes to the assumptions for the volume and distribution of pumpage in the Trinity Aquifer in the counties located within and surrounding the Woodbine Aquifer have the potential of affecting the managed available groundwater estimates described in this report.

REFERENCES:

Bené, J., Harden, B., O'Rourke, D., Donnelly, A., and Yelderman, J., 2004, Northern Trinity/Woodbine Groundwater Availability Model: contract report to the Texas Water Development Board by R.W. Harden and Associates, 391 p.

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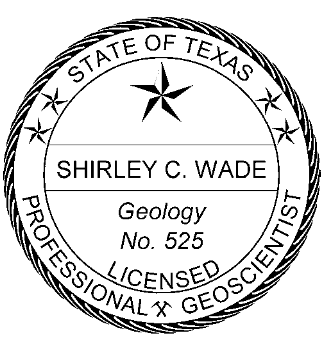

The seal appearing on this document was authorized by Shirley Wade, P.G., on May 6, 2008.