Chapter 10 References

Reference #	Reference	Copyrighted Information (Yes/No)	Will be provided to NRC (Yes/No)
Section 10.1	None	N/A	N/A
Section 10.2			
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Section 10.3	None	N/A	N/A
Section 10.4			
1.	CEED (Center for Energy and Economic Development) 2007, Fuel Diversity. Available at www.ceednet.org/ceed/index.cfm?cid=7500,7583, accessed June 12, 2007.	No	Yes
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2. World Nuclear Association 2005. *Supply of Uranium,* Available at http://www.world-nuclear.org/info/inf75.html, accessed May 16, 2007.

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MPR-2610
Revision 2
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Application of Advanced Construction Technologies to New Nuclear Power Plants

Prepared for

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Application of Advanced Construction Technologies to New Nuclear Power Plants

MPR-2610
Revision 2

September 24, 2004

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Executive Summary

As part of the U.S Department of Energy Nuclear Power 2010 (NP2010) initiative, MPR conducted an evaluation of advanced construction technologies that could potentially decrease the construction time of new domestic nuclear plants planned for deployment in the 2010 timeframe. Advanced construction technologies are those construction methods and techniques that were developed after completion of the last domestic nuclear plant (nearly 10 years ago).

Existing U.S. nuclear power plants were constructed using the methods and technologies from the 1970's and 1980's. Since then construction technology has advanced and these new technologies have been used in several applications, including foreign nuclear plant construction. Construction time for these recent foreign nuclear plants has been reduced to four years or less through the use of advanced techniques and technologies.

Thirteen advanced construction technologies were evaluated. The evaluations considered:

- Current applications of the technology
- Primary benefit of the technology to nuclear power plant construction, e.g., construction schedule improvement
- Potential for successful application at a nuclear plant in the U.S., including qualitative assessment of NRC acceptance
- Technical maturity of the technology (assessed qualitatively)
- Activities recommended for DOE to further advance the technology, e.g., research and development

Table ES-1 lists the technologies evaluated and whether use of the technology should be planned in constructing nuclear plants in the U.S. in the 2010 timeframe. Of the thirteen evaluated, MPR found that 12 of these technologies would benefit construction schedules for new, domestic nuclear plants. DOE should disseminate information regarding these twelve technologies to NSSS vendors, utilities, and constructors. It is incumbent on the vendor to develop/obtain expertise with these technologies prior to bidding on a new domestic nuclear plant project.

Nine of the twelve construction technologies recommended for use in domestic nuclear plant construction are sufficiently mature and have proven economic benefits (for most applications). These nine technologies, listed below, do not require additional research and development:

- Steel-Plate Reinforced Concrete Structures
- Concrete Composition Technologies (advanced concrete admixtures)

- High Deposition Rate Welding
- Robotic Welding
- 3D Modeling
- GPS Applications in Construction
- Open-Top Installation
- Pipe Bends vs. Welded Elbows
- Precision Blasting/Rock Removal

The remaining three construction technologies show promise for use in building a domestic nuclear plant and potentially have the largest impact on construction schedule reduction. However, each of these three construction technologies has issues that need further technical development, as summarized in Table ES-2. These three construction technologies are:

- Prefabrication, Preassembly, and Modularization
- Cable Splices
- Advanced Information Management and Control

The third technology, "Advanced Information Management and Control," is part of a significant research initiative by the National Institute of Standards and Technology (NIST). NIST is funding a project called FIATECH (Fully Integrated and Automated TECHnology, see Appendix L for details) to develop more fully integrated information processes to improve the efficiency (cost and schedule) of construction projects and the reliability of completed projects. Thus, this technology does not require DOE research funding.

However, the nuclear industry (e.g., NEI) should obtain information on FIATECH from NIST and conduct an investigation to assess the applicability of this project to improving project coordination for new nuclear plant construction in the U.S. Also, the investigation could assess the applicability of the FIATECH project to improving communications between the plant construction team and the NRC throughout construction.

Table ES-2 summarizes the conclusions and recommendations regarding the advanced construction technologies reviewed as part of this report, with details concerning research to support the application of some of the advanced construction technologies.

ES-1. Technologies Evaluated

Technology	Description	Recommended for Implementation
Steel-Plate Reinforced Concrete Structures	An alternative to structural concrete reinforced with steel bars: parallel steel plates are tied together with steel rods, and are joined by headed studs to concrete poured between the plates.	Yes
Concrete Composition Technologies	Advanced concrete admixtures are used to achieve increased strength and workability. Technology includes self-compacting concrete (SCC), high performance concrete (HPC), and reactive powder concrete (RPC).	Yes
Fiber-Reinforced Polymer Rebar Structures	An alternative to steel bar reinforced concrete; same construction technique as traditional reinforced concrete except reinforcing bars are fiber-embedded polymeric resin.	No —Advantages do not offset higher costs.
High Deposition Rate Welding	Specialized versions of traditional welding processes, including GMAW, GTAW (orbital welding), flux cored SAW, and strip clad welding. Processes offer higher deposition rates than their predecessors.	Yes
Robotic Welding	Automated welding for most types of manual welding processes, including GMAW, GTAW, flux cored arc welding, and SAW.	Yes
3D Modeling[Note 1]	Solid, 3-dimensional modeling computer software used for design work, construction, operations and maintenance.	Yes
Positioning Applications in Construction (GPS and Laser Scanning)	Global Positioning System (GPS) is worldwide radio-navigation system used to determine longitude, latitude, and altitude. Use of "Indoor GPS" (laser scanning) for process control inside fabrication facilities is being developed.	Yes
Open-Top Installation	Reactor building is partially completed and left open so that large components, e.g., reactor vessel and steam generators can be installed from above. After placement of large components, building is completed while piping and electrical systems are installed.	Yes
Pipe Bends vs. Welded Elbows	Welds between straight pipe and elbows are eliminated by pipe bent to specified geometries.	Yes
Precision Blasting/Rock Removal	Precise use of explosives to remove rock instead of mechanical excavation methods.	Yes
Cable Pulling, Termination and Splices	Advancements in lubricants for cable pulling, termination and splicing technologies, e.g., cold shrink, and acceptability of cable splices.	Yes
Advanced Information Management and Control	Computerized design databases centralize all design information, allowing access by all parties.	Yes
Prefabrication, Preassembly, and Modularization	Off-site prefabrication and preassembly of portions (modules) of a plant that are transported to the site for placement and connection with other modules.	Yes

Notes:
1. Does not address full-scale, virtual reality modeling, which could be considered for plants after 2010.

ES-2. Summary of Recommended Actions

Technology	Issues for Use at Domestic Nuclear Plant	Recommended Actions	Estimated Construction Schedule Improvement*
All	U.S. nuclear industry has little recent construction experience.	Make information on the technologies to significantly reduce construction schedule for new nuclear power plants widely available to U.S. nuclear industry organizations.	n/a
Prefabrication, Preassembly, and Modularization	1. Facilities may not be adequate to fabricate the modules at the rate required to meet schedules, especially if more than one plant is ordered. 2. Quality assurance requirements may hamper expansion of module fabrication capability.	1. Industry should assess module manufacturing capability, define gaps in capability under various construction demand scenarios, determine whether capabilities exist to fabricate the modules needed, define any gaps in capabilities or barriers to their use, and develop approaches to overcome the gaps. 2. Industry should assess the impact of 10 CFR 50 Appendix B QA requirements on the availability and feasibility of using PPM. Options for development of new QA methods or programs should be investigated. The findings of this review could be presented to the NRC to discuss measures to resolve the obstacles to increasing the number of domestic and foreign suppliers that meet QA requirements.	5 months
Cable Splicing	Cable splicing enhances modular construction by eliminating the need to pull cable through adjacent modules. Splices, however, are only accepted by the NRC under "special circumstances." The long lead time to adopt this technology will probably result in its not being available for the next nuclear plant in the U.S.	1. Perform environmental qualification testing of cold-shrink splices. This could be based on the application of splices in construction of nuclear-powered submarines or the testing used to certify cold-shrink splices for use on commercial ships. 2. Perform testing, possibly at a national laboratory such as Sandia or Brookhaven where cable insulation aging has been extensively studied, to show that aging of splices does not degrade overall cable performance. 3. Make results of this work widely available for evaluation to help change industry and NRC standard practice that restricts the use of splices, with the goal of the NRC revising applicable regulations to incorporate results of performance testing. These activities should be sponsored by an industry group such as EPRI, and DOE could consider co-sponsoring them to make this technology option available.	1.3 months
Steel-Plate Reinforced Concrete Structures	Ready for use in construction. Existing inspection techniques per ACI-349.3R will require modification since concrete is encased between steel plates and is not visible.	Plant operators will need to work with constructors and NSSS vendors that use this technology to adapt RC inspection methods and criteria for steel-plate reinforced concrete structures that meet NRC Maintenance Rule requirements.	2.3 months
Advanced Information Management and Control	Common formats for information sharing do not exist. Need to share information with NRC.	U.S. nuclear industry should assess the NIST FIATECH project for its applicability and usefulness. The results of this review could be presented to the NRC for possible application to the NRC's CIPIMS project.	n/a

* See Appendix N for the basis and analysis used to estimate the approximate duration of schedule reduction.

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1 Introduction

1.1 Purpose

This report identifies and assesses advanced construction technologies potentially applicable to new domestic nuclear plants planned for deployment in the 2010 timeframe. Advanced construction technologies are those construction methods and techniques that were developed after completion of the last domestic nuclear plant (10 years ago). Based on these assessments, recommendations are provided for technology developments, improvements, demonstrations, or other activities needed to shorten the construction schedule for advanced nuclear power plants in the United States.

1.2 Background

In February 2001, the United States Department of Energy (DOE) organized a Near-Term Deployment Group (NTDG) to examine prospects for deployment of new nuclear plants in the United States (U.S.) in this decade, identify obstacles to deployment, and develop actions for resolution. In October 2001, the NTDG published "A Roadmap to Deploy New Nuclear Power Plants in the U.S. by 2010." The recommendations of the Roadmap have been utilized by DOE to form the basis for a new initiative, Nuclear Power 2010 (NP2010). The NP2010 initiative is a joint government/industry cost-shared program to develop advanced reactor technologies and demonstrate new regulatory processes leading to a private sector order for a new nuclear power plant in the U.S. by 2005. NP2010 is an integrated program that aggressively pursues regulatory approvals and design completion in a phased approach, leading to the construction and startup of new nuclear plants in the United States in the 2010 timeframe.

Existing U.S. nuclear power plants were constructed using the methods and technologies from the 1970's and 1980's. Advanced construction technologies have been used abroad since the last new plant construction in the U.S. Specifically, Atomic Energy of Canada Limited (AECL) has built CANDU design reactors in China, South Korea has built System 80+ plants designed by Combustion Engineering (now owned by Westinghouse), and the Japanese have built several Advanced Boiling Water Reactor (ABWR) plants (designed by General Electric and licensed to Toshiba). Construction time for these recent facilities has been reduced to four years or less in some cases through the use of advanced techniques and technologies. These techniques and technologies were not used in the U.S. commercial nuclear industry. However, they are being used in the U. S. and internationally to accelerate the construction schedules of large construction projects (e.g., in fossil-fuel power plant construction, civil works, and shipbuilding). These techniques can potentially be applied to construction of new U.S. nuclear power plants.

In order to achieve the goals of the NP2010 Program, DOE initiated studies on evaluating construction time and cost, detailed engineering for construction, and operations costs for developing new nuclear power plants in the U.S. The DOE has selected a team of contractors having nuclear plant construction, architectural-engineering design, and operations experience to carry out these studies. This document reports the results of one of the studies carried out as part of the NP2010 Program. This report is a companion to MPR report MPR-2627, "DOE NP2010 Construction Schedule Evaluation," and a report by Dominion Energy titled "NP2010 Improved Construction Technologies, O&M Staffing and Cost, Decommissioning Costs, and Funding Requirements Study."

1.3 Scope

The NP2010 program addresses four reactor designs considered promising for near-term deployment in the United States:

- ABWR (offered by both GE and Toshiba)
- GE ESBWR
- Westinghouse AP1000
- Atomic Energy of Canada Limited (AECL) ACR-700

As shown in Table 1-1, the construction technologies applicable to each design are very similar. No advanced construction technologies have been identified that are uniquely applicable to a particular reactor design. The summary of findings regarding the various technologies is provided in Table 2-2 in the Conclusions and Recommendations section of this report.

1.4 Approach

The advanced construction technologies evaluated in this report were selected by reviewing developments in the construction industry that will have an impact on the major stages of the nuclear plant construction. These developments affect the following major activities:

- Excavation
- Reinforced concrete placement
- Material and component shipping
- Inventory Control
- Modularization
- Steel structure erection

- Vessel tank, piping and pipe support installation
- Electrical instrumentation and control installation
- Testing and startup
- Management of documentation design information

Technologies that have the potential to significantly improve the construction schedule for these major activities were selected. In particular, technologies that have been used successfully in similar applications, (e.g., foreign nuclear plants) or other large-scale construction activities (e.g., fossil fuel plants, petroleum plants or shipbuilding) were selected. The selection process was primarily based on professional judgment supported by company experience. Bechtel Power Corporation, a participant in the Dominion Energy study, also provided input to the technologies to be reviewed. Some candidate technologies were identified through literature reviews and participation in site visits. Site visits are documented in References 1, 2, and 3.

Each advanced technology was researched, evaluated, and summarized for this report. The evaluations consider:

- Primary benefit of the technology, e.g., construction schedule improvement
- Current applications of the technology
- Main hurdle to successful application at a nuclear plant in the U.S., including qualitative assessment of NRC acceptance
- Qualitative assessment of technical maturity
- Suggested follow-up activity by DOE, e.g., research and development

Detailed information on each construction technology is provided in a separate appendix to this report. References providing information about each construction technology are included in each technology's appendix to this report.

Table 1-1. Planned Use of Advanced Construction Technologies

Advanced Construction Technology	ABWR	ESBWR	AP1000	ACR-700
Steel-Plate Reinforced Concrete Structures	No	No	Yes	No
Concrete Composition Technologies	Yes	Yes	Not Determined	Yes
Fiber-Reinforced Polymer Rebar Structures	No	No	No	No
High Deposition Rate Welding	Yes	Yes	Not Determined	Yes
Robotic Welding	Yes	Yes	Not Determined	Yes
3D Modeling[1]	Yes	Yes	Yes	Yes
Positioning Applications (GPS and Laser Scanning)	Yes	Yes	Not Determined	Yes
Open-Top Installation	Yes	Yes	Yes	Yes
Pipe Bends vs. Welded Elbows	Yes	Yes	Not Determined	Yes
Precision Blasting/Rock Removal	Site Specific	Site Specific	Site Specific	Site Specific
Cable Pulling, Termination and Splices[2]	No	No	No	No
Advanced Information Management and Control[1]	Yes	Yes	Yes	Yes
Prefabrication, Preassembly, and Modularization[1]	Yes	Yes	Yes	Yes

[1] This technology is used by different vendors in varying degrees.
[2] Entries refer to use of splices between modules.

2 Conclusions and Recommendations

2.1 Conclusions

Thirteen advanced construction technologies were evaluated for their applicability to new domestic nuclear power plants. Table 2-2 summarizes the results of these evaluations. This table provides a brief description of each technology, and identifies the benefits and obstacles to implementation in domestic nuclear plant construction. Each construction technology is discussed in greater detail in the appendix noted in Table 2-2.

Twelve of the thirteen technologies evaluated should be planned for use in constructing nuclear plants in the U.S. in the 2010 timeframe. Nine of the twelve construction technologies recommended for domestic nuclear plant construction are sufficiently mature and have proven economic benefits (for most applications) that they do not require additional research and development. These nine construction technologies are:

- Steel-Plate Reinforced Concrete Structures
- Concrete Composition Technologies (advanced concrete admixtures)
- High Deposition Rate Welding
- Robotic Welding
- 3D Modeling
- GPS Applications in Construction
- Open-Top Installation
- Pipe Bends vs. Welded Elbows
- Precision Blasting/Rock Removal

The remaining three construction technologies show promise for use in building a domestic nuclear plant and potentially have the largest impact on construction schedule reduction. However, each of these three construction technologies has issues that need further technical development. These three construction technologies are:

- Prefabrication, Preassembly, and Modularization

- Cable Splices
- Advanced Information Management and Control

The first two technologies have the potential to individually reduce overall construction schedules by approximately 5 months and 1.3 months, respectively, compared to a schedule where the technology is not used, if the issues identified with their use in the construction of a domestic nuclear plant can be resolved. The nuclear industry would receive significant benefit from research and development support of all three of these technologies.

Because of the successful application of prefabrication, preassembly, and modularization in the construction of fossil power plants and various other projects in the U.S., and in nuclear plant construction outside the U.S., the nuclear industry has been preparing for extensive use of this technology in the next generation of plants to be built in the U.S. Additionally, the NRC has been preparing for the change in inspection processes to accommodate the fabrication and construction of large components away from the plant site, and has been working with industry to demonstrate these new inspection processes. These preparations are still in progress and further effort is needed to make the use of prefabrication, preassembly, and modularization a reality for nuclear plant construction. Recommendations for these actions are in section 2.2 of this report.

The third technology in the group requiring further effort, "Advanced Information Management and Control," is the subject of a significant research initiative by the National Institute of Standards and Technology (NIST), see Appendix L for details of this project. The need for the use of this technology is also explicitly recognized and required in the "U.S. Advanced Light Water Reactor (ALWR) Utility Requirements Document." The NRC is separately developing a Construction Inspection Program Information Management System (CIPIMS) to track inspection, test, analysis, and acceptance criteria (ITAAC) during construction of new nuclear power plants. Although Advanced Information Management and Control may not require industry and DOE research, the industry and NRC may benefit from an assessment of the NIST project and its applicability to new nuclear plant construction and the CIPIMS project.

2.2 RECOMMENDATIONS

2.2.1 Disseminate Findings of this Study to the Nuclear Industry

DOE should make the findings of this report available for NSSS vendors, architect/engineers, and potential plant owners. DOE should focus attention on the twelve advanced construction technologies identified in Table 2-2 to benefit construction schedules for new domestic nuclear plants. It is expected that NSSS vendors and constructors will develop/obtain expertise with these technologies prior to bidding on a new domestic nuclear plant project.

Additionally, DOE should consider sponsoring an information conference with NSSS vendors, nuclear industry A/E firms, and potential utility owners to ensure they have information available on each technology. Vendors that support the advanced technologies should be invited to present available information on the technologies.

2.2.2 Research and Development Activities

DOE should consider co-funding industry-led research in the application of the two advanced construction technologies listed in Table 2-1 as requiring work to be ready to support construction. These technologies are listed in order of priority based on the expected benefit of the technology relative to the expected costs. The basis for the assigned priorities is as follows:

First Priority -- Prefabrication, preassembly, and modularization. This technology has the most potential for nuclear plant construction time savings (estimated to be at least five months). However, significant investment will be required to implement this technology for construction of new nuclear power plants in the United States. Given the extensive recent use of this technology for fossil power plants and for nuclear powered aircraft carriers and submarines, the remaining issues are the application of commercial nuclear power quality standards, ensuring non-U.S. module fabricators can produce the required quality and meet tight schedule demands, and maximizing the cost-effective incorporation of this technology into new plant designs and construction plans.

Second Priority -- Cable splicing. Using splicing on a more widespread basis is expected to decrease construction times by approximately one month. Although this is a small time savings relative to other technologies presented here, the cost to implement cable splicing should be very low. The primary hurdle is regulatory, and a long lead time is anticipated for research required to demonstrate the acceptability of splices, change regulatory positions, and make this a feasible alternative to standard industry practice. Thus, this technology will probably not be available for inclusion in construction plans for the next new nuclear plants to be built in the U.S.

2.2.2.1 Prefabrication, Preassembly, and Modularization

Prefabricating major sections of nuclear plants has the potential to shorten the overall construction schedule by an estimated 5 months. Prefabrication, preassembly, and modularization (PPM), which relies on off-site fabrication capability and transportation infrastructure, will place heavy loads on the existing module fabrication infrastructure in the U.S., will require significant quality assurance effort to obtain modules from foreign fabricators, and could place the shortened construction schedules at risk because of those schedules' dependence on timely delivery of modules. Further evaluation and support for resolution of these issues, possibly by a DOE-nuclear industry cost-share arrangement, is recommended as follows:

1. Industry should conduct a review of manufacturing facilities to determine whether capabilities exist for fabricating the large modules needed for this technology at the rate required to support proposed construction schedules, define any gaps in capabilities or barriers to their use, and develop approaches to overcome the gaps. While DOE trips to U.S. Navy shipyards and to facilities in Japan found substantial capability for module fabrication for nuclear plants, some obstacles to use of PPM that should be considered are: ability to increase production capacity if more than one plant is ordered, and the ability to meet challenging production and delivery schedules.

2. Assess the impact of 10 CFR 50 Appendix B quality assurance (QA) requirements on the availability and feasibility of using PPM. The quality assurance requirements will prevent some suppliers capable of producing modules from participating because of the expense of establishing and maintaining a 10 CFR 50 Appendix B QA program. The number of fabricators that can meet presently defined QA requirements may be small and the industry may not have the capacity to respond to increased demand or short construction schedules. Options for development of new QA methods or programs should be assessed. The findings of this review could be presented to the NRC to discuss measures to resolve the obstacles to increasing the number of domestic and foreign suppliers that can meet QA requirements.

2.2.2.2 Cable Splicing

The use of cable splices as part of modular construction is estimated to shorten new nuclear plant construction schedules by approximately 1 month out of a 66-month construction schedule. Therefore, the feasibility and desirability of using this technology should be investigated. MPR recommends that the following actions be taken as part of a nuclear industry-sponsored effort:

1. Perform environmental qualification testing of cold-shrink splices. This could be based on the application of splices used in construction of nuclear-powered submarines and the testing used to certify cold-shrink splices for use on commercial ships. The testing should be planned with NRC participation to ensure it addresses potential regulatory concerns.

2. Perform testing, possibly at a national laboratory such as Sandia or Brookhaven where cable insulation aging has been extensively studied, to show that aging of splices does not degrade overall cable performance. The testing should be planned with NRC participation to ensure it addresses potential regulatory concerns.

3. Make results of this work widely available for use in efforts to change industry and NRC standard practice that restricts the use of splices, with the goal of the NRC revising regulatory guidance to incorporate results of performance testing and accepting the use of splices to enhance modular construction. This will support envisioned application of a modularization strategy incorporating splices in new domestic nuclear plant designs and construction plans.

These activities could be co-sponsored by DOE if DOE and industry determine that making this technology available as a construction technique would be a worthwhile effort. The long lead time to adopt splicing technology as industry practice will probably result in its not being available within the next 5 years for the next nuclear plant construction in the U.S.

2.2.2.3 Advanced Information Management and Control

The NIST is funding a project called FIATECH (Fully Integrated and Automated TECHnology, see Appendix L for details) to develop more fully integrated information processes to improve the efficiency (cost and schedule) of construction projects and the reliability of completed projects. Thus, this technology does not require DOE research funding.

However, the nuclear industry (e.g., NEI) should obtain information on FIATECH from NIST and conduct an investigation to assess the applicability of this project to improving project coordination for new nuclear plant construction in the U.S. Also, the investigation could assess the applicability of the FIATECH project to improving communications between the plant construction team and the NRC throughout construction. The investigation should determine steps needed to resolve any NRC concerns about safety-related electronic documentation and safeguarding any sensitive information related to plant security. An assessment of the NIST project is recommended because it could improve the process of inspections and approvals by NRC during plant construction, in addition to increasing efficiency during construction. Industry should conduct this assessment and invite the NRC to participate.

Table 2-1. Summary of Recommended Actions

Technology	Issues for Use at Domestic Nuclear Plant	Recommended Actions	Estimated Construction Schedule Improvement*
All	U.S. nuclear industry has little recent construction experience.	Make information on the technologies to significantly reduce construction schedule for new nuclear power plants widely available to U.S. nuclear industry organizations.	n/a
Prefabrication, Preassembly, and Modularization	1. Facilities may not be adequate to fabricate the modules at the rate required to meet schedules, especially if more than one plant is ordered. 2. Quality assurance requirements may hamper expansion of module fabrication capability.	1. Industry should assess module manufacturing capability, define gaps in capability under various construction demand scenarios, determine whether capabilities exist to fabricate the modules needed, define any gaps in capabilities or barriers to their use, and develop approaches to overcome the gaps. 2. Industry should assess the impact of 10 CFR 50 Appendix B QA requirements on the availability and feasibility of using PPM. Options for development of new QA methods or programs should be investigated. The findings of this review could be presented to the NRC to discuss measures to resolve the obstacles to increasing the number of domestic and foreign suppliers that meet QA requirements.	5 months
Cable Splicing	Cable splicing enhances modular construction by eliminating the need to pull cable through adjacent modules. Splices, however, are only accepted by the NRC under "special circumstances." The long lead time to adopt this technology will probably result in its not being available for the next nuclear plant in the U.S.	1. Perform environmental qualification testing of cold-shrink splices. This could be based on the application of splices in construction of nuclear-powered submarines or the testing used to certify cold-shrink splices for use on commercial ships. 2. Perform testing, possibly at a national laboratory such as Sandia or Brookhaven where cable insulation aging has been extensively studied, to show that aging of splices does not degrade overall cable performance. 3. Make results of this work widely available for evaluation to help change industry and NRC standard practice that restricts the use of splices, with the goal of the NRC revising applicable regulations to incorporate results of performance testing. These activities should be sponsored by an industry group such as EPRI, and DOE could consider co-sponsoring them to make this technology option available.	1.3 months
Steel-Plate Reinforced Concrete Structures	Ready for use in construction. Existing inspection techniques per ACI-349.3R will require modification since concrete is encased between steel plates and is not visible.	Plant operators will need to work with constructors and NSSS vendors that use this technology to adapt RC inspection methods and criteria for steel-plate reinforced concrete structures that meet NRC Maintenance Rule requirements.	2.3 months
Advanced Information Management and Control	Common formats for information sharing do not exist. Need to share information with NRC.	U.S. nuclear industry should assess the NIST FIATECH project for its applicability and usefulness. The results of this review could be presented to the NRC for possible application to the NRC's CIPIMS project.	n/a

* See Appendix N for the basis and analysis used to estimate the approximate duration of schedule reduction.

Table 2-2. Summary of Findings

Appendix	Technology	Description	Current Applications		Primary Benefit	Main Obstacle to Domestic Nuclear Plant Use	Recommended for Implementation
			Country	Project			
A	Steel-Plate Reinforced Concrete Structures	An alternative to structural concrete reinforced with steel bars: parallel steel plates are tied together with steel rods, and are joined by headed studs to the concrete poured between the plates.	Japan	Low level radioactive waste incinerator building	Speeds construction of structural concrete because rebar mats are eliminated, and formwork is integral with the structural member, i.e., no need to remove formwork after concrete cures	Ready for use in construction except for structures with steel liners; these will have additional design issues, e.g., Code does not count strength of liners. For other applications, the plant operators will need to adapt existing inspection methods and criteria to meet ACI-349.3R and NRC requirements.	Yes
B	Concrete Composition Technologies	Advanced concrete admixtures are used to achieve increased strength and workability. Technology includes self-compacting concrete (SCC), high performance concrete (HPC), and reactive powder concrete (RPC).	Worldwide France	Various civil construction projects Medium-level radioactive waste storage	Reduces quantities of concrete for same strength Improves concrete workability	None Techniques are treated in the same manner as traditional methods	Yes
C	Fiber-Reinforced Polymer Rebar Structures	An alternative to steel bar reinforced concrete: same as traditional reinforced concrete except reinforcing bars are fiber-embedded polymeric resin.	Worldwide	Bridge beams and decking	Reduces weight of concrete structures Better corrosion resistance than steel reinforced concrete	Reduced fire resistance compared to conventional reinforced concrete Higher costs	No — Advantages are less significant for nuclear plants than for bridges, so higher costs are not offset.

Appendix	Technology	Description	Current Applications		Primary Benefit	Main Obstacle to Domestic Nuclear Plant Use	Recommended for Implementation
			Country	Project			
D	High Deposition Rate Welding	Specialized versions of traditional welding processes, including GMAW, GTAW (orbital welding), flux cored SAW, and strip clad welding, that have higher deposition rates than their predecessors.	Japan	Used for production of nuclear plants	Speeds production of: 1. steel-plate joining, e.g., between SC modules 2. large bore pipe installation 3. components requiring cladding	None Techniques are treated in the same manner as traditional methods	Yes
E	Robotic Welding	Automated welding for most types of manual welding processes, including GMAW, GTAW, flux cored arc welding, and SAW.	Japan, China, France	Used for fabrication of nuclear plant components	Greater productivity and higher quality in welding	None Techniques are treated in the same manner as traditional methods	Yes
			U.S.	Used for some nuclear plant component repairs			
F	3D Modeling[Note 1]	Solid, 3-dimensional modeling computer software is used for design work, construction, operations and maintenance.	Worldwide	De facto industry requirement	Speeds design and allows verification of finished assembly layouts	None Technique is treated in the same manner as traditional methods	Yes
G	Positioning Applications in Construction (GPS and Laser Scanning)	Global Positioning System (GPS) is worldwide radio-navigation system used to determine longitude, latitude, and altitude. Use of "Indoor GPS" (laser scanning) for process control inside fabrication facilities is being developed.	Worldwide	GPS is de facto requirement for site prep on geographically extensive projects	Speeds site preparation and survey work with increased accuracy and reduced re-work	None Technique is treated in the same manner as traditional methods	Yes

Appendix	Technology	Description	Current Applications		Primary Benefit	Main Obstacle to Domestic Nuclear Plant Use	Recommended for Implementation
			Country	Project			
H	Open-Top Installation	Reactor building is partially completed and left open so that large components, e.g., reactor vessel and steam generators can be installed from above. After placement of large components, building is completed while piping and electrical systems are installed.	Japan, China, Taiwan	Nuclear plant construction since mid-1990's	Speeds completion of work in reactor building	None Technique is treated in the same manner as traditional methods	Yes
I	Pipe Bends vs. Welded Elbows	Welds between straight pipe and elbows are eliminated by pipe bent to specified geometries.	Japan, China	Nuclear plant construction	Reduces lifetime costs of in-service inspections by reducing number of welds	None Technique is treated in the same manner as traditional methods	Yes
			U.S.	Construction of various projects including U.S. Navy nuclear plants			
J	Precision Blasting/Rock Removal	Precise use of explosives to remove rock instead of using mechanical excavation methods.	U.S.	Used to excavate Millstone Unit 3	Faster excavation of rock without shutting down nearby operating plants.	None This technology has been used at a domestic nuclear plant	Yes
K	Cable Pulling, Termination and Splices	Advancements in lubricants for cable pulling, termination and splicing technologies, e.g., cold shrink, and acceptability of cable splices.	U.S.	Used in military and commercial shipbuilding to aid modular construction	Splices would allow significant reduction in cable pulling time, especially when used with modular construction	Splices are accepted by NRC but only under "special circumstances" Splices could be aging management issue	Yes

Appendix	Technology	Description	Current Applications		Primary Benefit	Main Obstacle to Domestic Nuclear Plant Use	Recommended for Implementation
			Country	Project			
L	Advanced Information Management and Control	Computerized design databases centralize all design information, allowing access by all parties.	U.S.	Fossil power plant construction	Speeds access to design and construction drawings, specifications, inspection records, etc.	Need NRC acceptance for safety-related electronic documentation. Need development of common information standards for sharing by construction project team.	Yes
M	Prefabrication, Preassembly, and Modularization	Off-site prefabrication and preassembly of portions (modules) of a plant that are transported to the site for placement and connection with other modules.	Japan, China	Used for nuclear plant construction	Speeds construction time	1. Facilities may not be adequate to fabricate the large, complex modules needed for this technology at the rate required to meet schedules, especially if more than one plant is ordered. 2. Quality assurance requirements may hamper expansion of module fabrication capability both in the U.S. and abroad for construction of U.S. plants.	Yes

Notes:
1. Does not address full-scale, virtual reality modeling, which could be considered for plants after 2010.

3 Discussion

Thirteen technologies that could potentially be applied in the construction of nuclear power plants in the U.S. were researched and evaluated as described in Appendices A through M. These technologies were selected by identifying major activities required to support nuclear plant construction by the year 2010 and surveying construction experience to identify progress since the last domestic nuclear plant construction was completed in the early 1990's[3]. Construction activities include:

- Excavation
- Reinforced concrete placement
- Material and component shipping
- Inventory control
- Modularization
- Steel structure erection
- Vessel tank, piping and pipe support installation
- Electrical instrumentation and control installation
- Testing and startup
- Management of documentation design information

For the next nuclear plant built in the U.S. to meet the goal of the DOE NP2010 Program the period of construction must be essentially halved relative to the historical average. Over the thirty-two year history of domestic nuclear plant construction, the construction period has averaged in excess of 9 years[4]. The NP2010 goal is approximately half that duration. It should be noted that construction schedules consistent with the NP2010 goal were achieved for a number of older domestic nuclear plants and are currently being achieved in the construction of foreign nuclear plants.

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[3] Watts Bar 1, the last domestic reactor to come on-line, first operated on May 27, 1996. However, the major construction activities on the unit were complete by the early 1990's.

[4] Another benchmark construction project duration, used elsewhere in this report, is 66 months (Reference 12). This value, measured from construction permit issue date to fuel load, includes only domestic nuclear power plants completed by 1979 (Reference 1), thereby omitting the effects of the regulatory changes following the 1979 accident at Three Mile Island Unit 2.

The goal of this evaluation was to identify technologies developed during the last 20 years that could significantly shorten the construction period in the US.

The evaluations of the different technologies considered the following: current applications and experience with the technology, potential benefit of the technology and potential code/regulatory issues. Twelve technologies were determined to have potential application in new domestic nuclear plant construction.

One additional group of technologies, advanced cutting methods, was evaluated but not included in the appendices. It was concluded that use of advanced cutting methods would not significantly shorten the construction schedule or considerably reduce costs.

The potential improvement in construction schedule was quantified for three of the construction technologies: steel-plate reinforced concrete structures; cable splicing; and prefabrication, preassembly, and modularization. The potential improvement in construction schedule from each advanced construction technology is summarized in Table 2-1. Appendix N details the estimates developed. For these three technologies to be available for new domestic nuclear plant construction, additional research and development is required. Quantifying the potential schedule improvement provides a basis for determining whether funds should be allocated to resolve the issues with each technology and to prioritize these efforts. Since the other eight technologies recommended for implementation do not require significant resources from DOE to assist in reaching maturity, they were not quantitatively assessed for construction schedule improvement.

4
References

References 1 through 3 below are cited in the main body of the report. References for specific construction technologies are provided in the individual appendices. Some key appendix references, References 4 through 15 below, are provided here as a summary.

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A
Steel-Plate Reinforced Concrete Structures

Many of the structures, foundations, and containments (e.g., reactor containment, auxiliary buildings, spent fuel storage, etc.) in previous nuclear power plants were constructed from reinforced concrete. This construction used built-in-place, reinforcing bars with external forms to frame and reinforce the structure prior to the placement of concrete. This construction technique required a long construction period including the construction and demolition of the form work and its supports. The placement of reinforced concrete structures was a major part of the overall plant construction schedule, typical of large-scale construction projects.

An alternative construction technique for reinforced concrete is steel-plate reinforced concrete (Reference 1). A steel-concrete-steel composite structure is constructed by placing concrete between two steel plates that form the concrete and provide the permanent exterior face of the structure. Studs welded on the inner surface of the steel plates are embedded in the concrete to tie the concrete and steel plates together. For erection purposes, the steel plates are connected together with tie-bars. Figure A-1 shows isometric views comparing standard reinforced concrete and steel-plate reinforced concrete construction. This new building construction technique can be used in the construction of the floors and walls of the reactor building, and for atmospheric tanks, as proposed in Westinghouse's AP600 and AP1000 (References 2, 3 and 10).

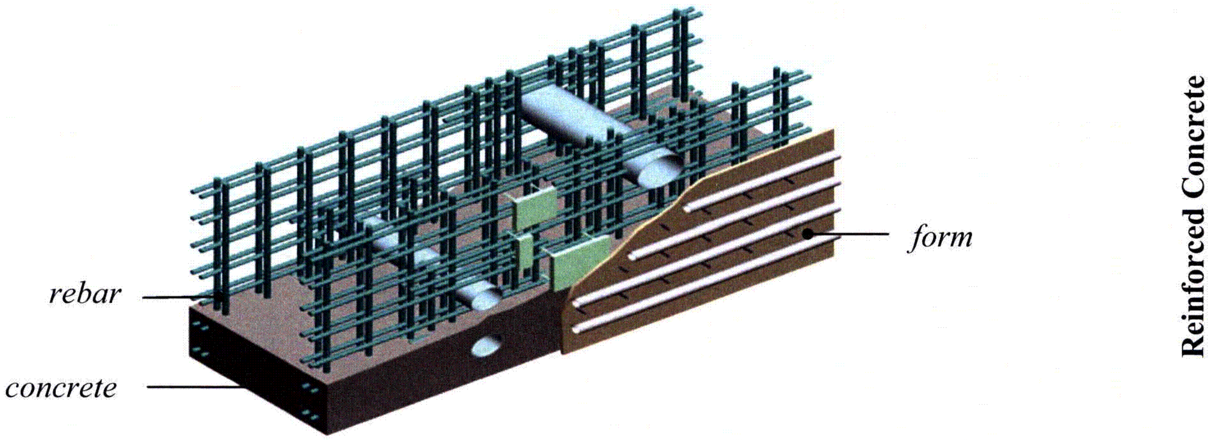
1. Implementation Experience

This method of erecting reinforced concrete structures was first used in 2002 in the construction of an auxiliary building (the incinerator building) at the Kashiwazaki-Kariwa 6 and 7 nuclear power plant site in Japan (Reference 1). TEPCO is planning to use this method for construction of the reactor containment building for the Fukushima 7 & 8 reactors scheduled to begin commercial operations in 2007 and 2008. The specific methods used by TEPCO were developed in Japan.

Similar techniques are being developed in the U.S. and United Kingdom (References 4 and 10). However, literature describing the use of this specific technique in U.S. construction projects was not found.

2. Benefits

Steel-plate reinforced concrete construction (SC) methods offer significant schedule advantages compared with conventional reinforced concrete construction (RC). The construction schedule is shortened because placement of rebar and removal of formwork are eliminated by the steel plate method. Based on information published by TEPCO (Reference 1), the steel-plate reinforced



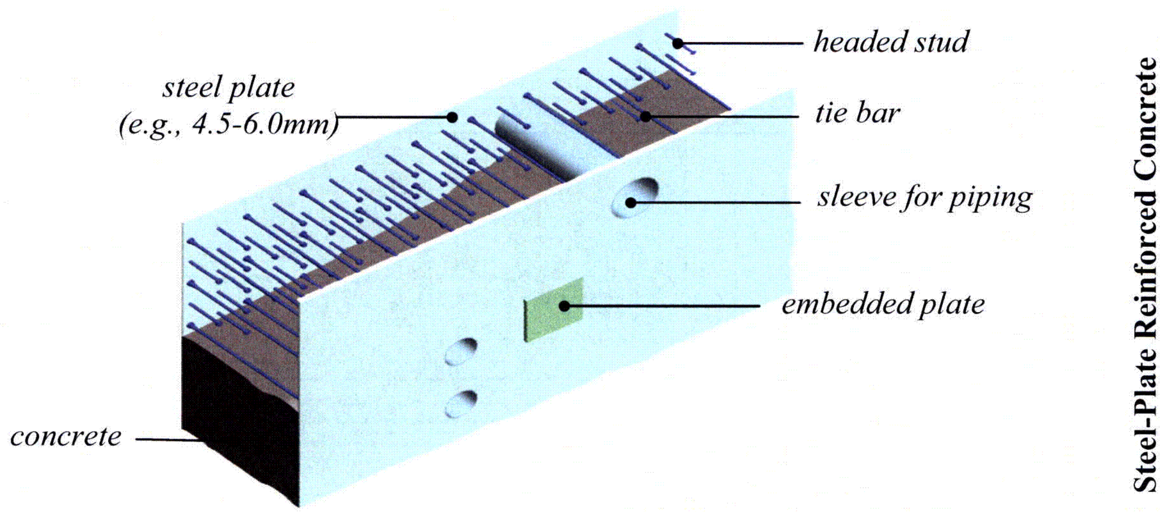


Figure A-1. Comparison of Reinforced Concrete Construction (Reference 1)

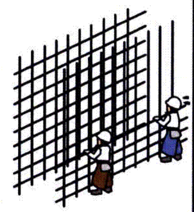
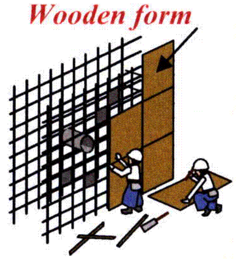
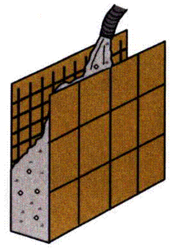
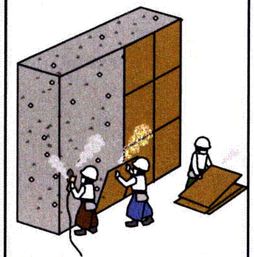
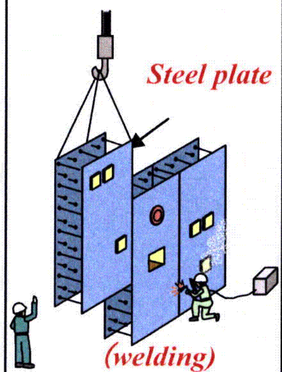
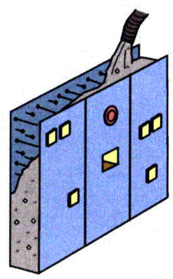
Work / Structure	*Rebar arrangement*	*Form work (assembling*	*Placing concrete*	*Form work (removal)*
RC				
28days	*13days*	*7days*	*4days*	*4days*
SC	——			——
14days	–	*10days*	*4days*	–

Figure A-2. Comparison of Construction Schedules for Reinforced Concrete

concrete wall construction is twice as fast as similar reinforcing bar reinforced concrete construction (see Figure A-2). Since the steel-plate structure is designed to be self-supporting, it is possible to fabricate the reinforced concrete sections as modules off-site, transport them as a unit to be placed on-site, and welded together (Reference 5). This construction technique results in a significant reduction in the work on-site prior to the concrete pour. Further, there is only limited form work to remove after the concrete has set.

Based on a cost analysis performed by TEPCO, the difference in cost of steel-plate reinforced concrete compared to the cost of RC reinforced concrete is dependent on several factors. Specifically, SC reinforced concrete construction method reduces the on-site work man-days by about 25%, as shown in Figure A-3. This corresponds to a reduced cost in labor. Additionally, the quantity of steel needed for an SC structural element (e.g., slab) is about 25% less than that required for an RC structural element with comparable strength (see Figure A-4). Although the fabrication cost is higher for the SC method, since the cost of steel plate is higher than the cost of reinforcing bar, the overall net production costs with the SC method are lower.

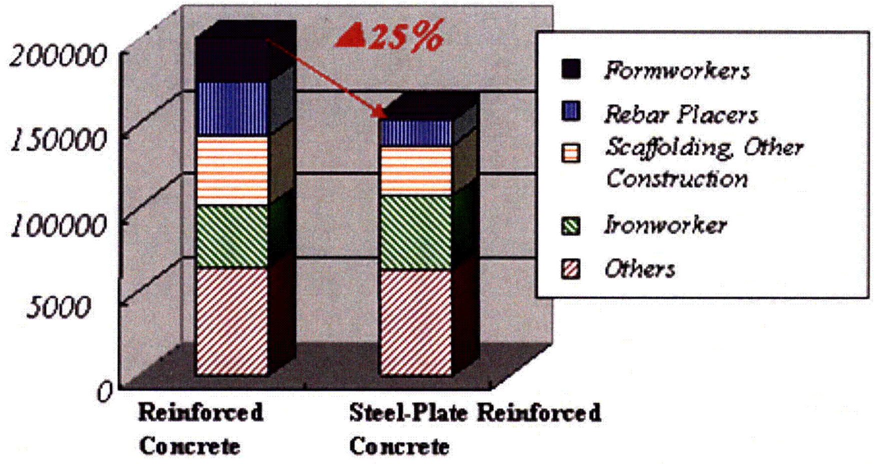


Figure A-3. Comparison of the On-Site Man Power Requirements

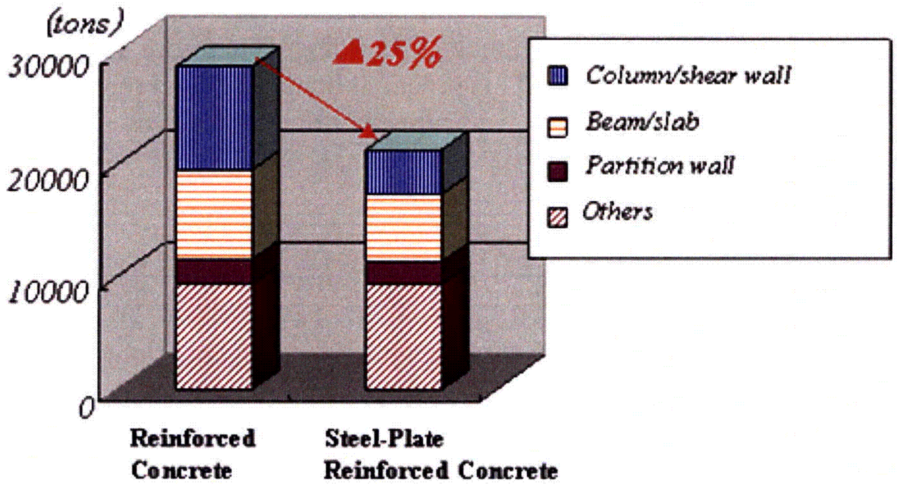


Figure A-4. Comparison of the Quantity of Steel Requirements

The seismic load carrying capability of SC construction design is a key factor for a nuclear structure. Based on TEPCO data, the deformation capacity for the SC reinforced concrete structure is 1.5 times greater than for an RC reinforced concrete structure. Figure A-5 shows plots of shear stress capability versus the deformation angle for each of these structures.

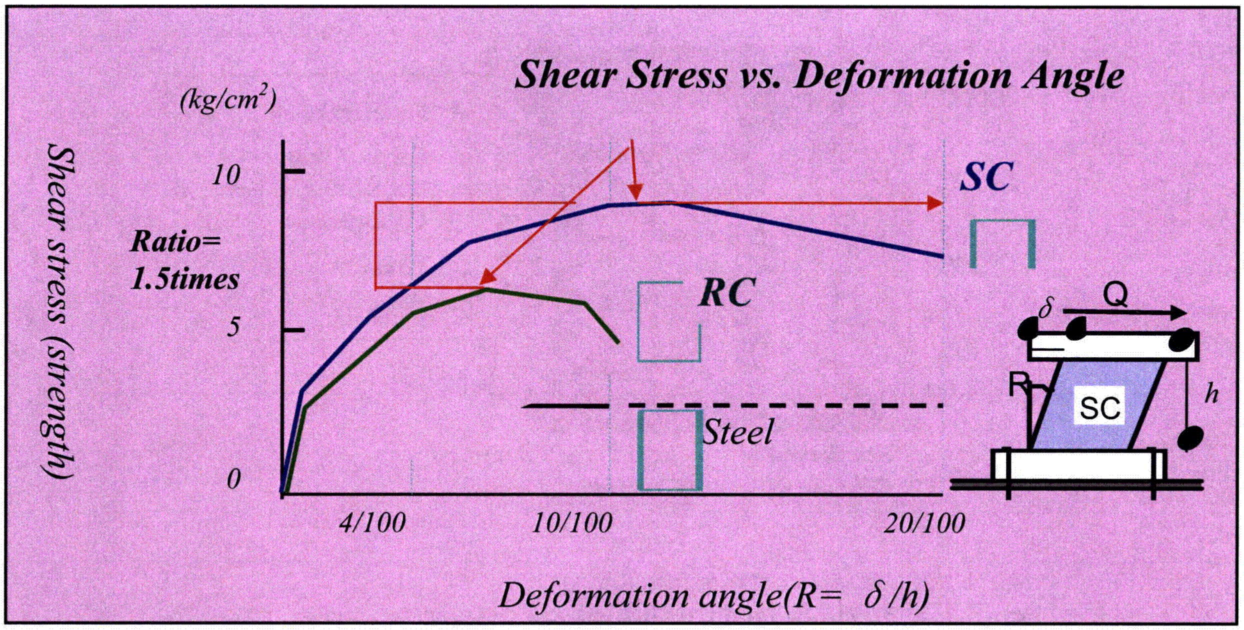


Figure A-5. Shear Stress vs. Deformation Angle

Additionally, TEPCO states that a building constructed using SC technology can be more easily dismantled and for less cost than a conventional RC building. Therefore, decommissioning these structures could be more easily achieved. This potential benefit of steel plate construction, which appears to be technically reasonable, was not supported in detail by the available references.

3. Code and Regulatory Issues

Based on discussions with Westinghouse (Reference 10), their AP1000 design would not use SC construction for the containment, although other structures, e.g., some floors and pools/tanks, would use the SC technology. Therefore, the ASME Boiler and Pressure Vessel Code for Steel-Lined Concrete Containments does NOT apply, and the governing code is ACI-349 (Reference 7).

The NRC has addressed the use of SC modular structures for safety-related applications in regulatory position 13 of Regulatory Guide 1.142. The NRC requires that design of SC modular structures follow guidelines in ACI-349 to ensure adequate structural strength to support required loads and withstand the design basis earthquake. Regulatory Guide 1.142 states that the NRC will evaluate applications of SC structures in safety-related buildings on a case-by-case basis until ACI-349 is revised to contain more specific requirements regarding SC.

SC construction is potentially more susceptible than RC to loss of strength or deformation when exposed to fire because, unlike RC construction, the steel reinforcement is not covered by concrete. According to Westinghouse, when the NRC certified the AP600 design they accepted the Westinghouse approach of analyzing the fire loading in each space enclosed by SC construction. For areas that have very low fire loading, the steel plate alone is an acceptable fire barrier. This approach would likely be accepted again for other advanced designs.

Although the NRC did not address aging management of SC structures in their certification of the AP600 or in Regulatory Guide 1.142, the NRC's Maintenance Rule does require periodic evaluation of safety-related structures, some of which may be SC construction (see ACI-349.3R, Reference 8). For RC construction, the periodic evaluations in ACI-349.3R depend mainly on visual inspection. The ACI-349.3R committee presently does not consider that use of SC structures will require development of special inspection processes or guidance. The NRC has not indicated that they will disagree with this approach. Westinghouse, in its planning for preparation of COL applications for the AP1000, also does not anticipate the need to develop specific inspection guidance for SC structures. The owner/operator of a plant containing SC safety-related structures will need to develop inspection guidelines, procedures, and techniques for inspection, especially as a plant built using SC structures ages.

4. Summary

The steel-plate reinforced concrete construction method offers the potential for significant reduction in construction schedule and costs in the next generation of nuclear power plants. Improvements in plant layout and overall size may also be realized from the improved structural capability of steel-plate reinforced concrete construction methods. Attention to the NRC-sanctioned approach to fire protection of steel-plate reinforced concrete will be required in implementing this construction technique.

This is a promising technology whose development for use in domestic nuclear power construction should result in benefits to the constructor and plant owner. Note that after the plant is constructed, the owner will need to have detailed processes in place for complying with the periodic inspection requirements for SC construction in the governing ACI Code and NRC Maintenance Rule.

Although not applicable to containment structures of Generation III+ plants considered by the NP2010 Program, it is noted that extension of this construction technique to primary containment structures will require further development of the technique and expansion of the existing code design requirements.

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B
Concrete Composition Technologies

Traditional concrete has been revolutionized since the construction of the most recent domestic nuclear power plants. These advancements are due to the use of admixtures to conventional concrete that modify its characteristics. In addition to increasing the comprehensive strength of the concrete, available admixtures can improve other characteristics, such as low permeability, limited shrinkage, and increased corrosion resistance. These changes can also reduce the curing time required by reducing the required thickness of concrete members as well as the reducing the number of special construction steps involved in curing.

Admixtures are used to improve a specific characteristic of the concrete for a specific application. Some of these improvements include water reduction in the mix, strength enhancement, corrosion protection, set acceleration, and crack control. Hardening accelerators, like Rapid-1, are used to allow the development of very early high strengths in concrete (Reference 1). This hardening accelerator is non-chloride (non-corrosive) and does not limit the long-term strength gain of concrete, whereas the strength gain may be sacrificed when other set accelerators are used. The advantages are a more placeable concrete for improved construction productivity without performance tradeoffs. Additionally, this product can be used in combination with a superplasticizer without modifying its properties. ASTM C494 specifies the requirements for several of these concrete admixtures.

Self-compacting concrete (SCC) is a special type of concrete mixture that has a high resistance to segregation (References 2 and 4). It can be cast without compaction or vibration. SCC, also known as self-placing concrete, is obtained by the addition of a water reducing agent to a conventional concrete mix. The water cement ratio remains the same in the mixture. SCC is a "flowable" concrete with high compressive strength. MELFLOW is an example of the type of superplasticizer used to produce SSC (Reference 1). This admixture optimizes the water/cement ratio of the concrete, dramatically improving its workability without having to add more water.

High performance concrete (HPC) is made with a combination of several different admixtures (e.g., superplasticizer, flyash, silica fume, etc.) to produce the required mix design properties (Reference 1). When properly mixed, transported, placed, consolidated, and cured, it provides higher performance (e.g., high compressive strength, high density, and low permeability) than traditional concrete. In addition, compressive strength for HPC is typically between 101 MPa (14.7 ksi) and 131 MPa (19 ksi), whereas traditional concrete compressive strength ranges from 2.5 ksi to 5 ksi.

Reactive powder concrete (RPC) provides the capability for even higher compressive strengths than can be achieved with HPC (Reference 1). Concrete compressive strength can be increased as high as 200 MPa (29 ksi). RPC is produced by including individual metallic fibers in a dense cement matrix. This reinforcement also increases the ductility of RPC in comparison to traditional concrete.

1. Implementation Experience

SCC is widely used in Japan in the construction of large scale projects such as bridges, buildings, tunnels, dams, and LNG tanks (Reference 1).

HPC has been used extensively in bridges in Germany, Virginia, and New York (References 5 and 6). The use of HPC is being encouraged for bridges and other highway structures by the Federal Highway Administration.

The French Atomic Energy Commission (CEA) has permitted the use of RPC to fabricate High Integrity Containers (HIC) for long-term interim storage of medium-level nuclear wastes (Reference 3). Current technology involves steel or cement-based multiple-walled containers in which wastes are immobilized by the injection of concrete or grout. Containers made with RPC are currently being developed for "bulk" packaging of the wastes. RPC has also been used to construct a pedestrian bridge in Canada.

Hardening accelerators have been used in the United States for several years. Applications include repairs to bridges, highways, and other concrete structures. Due to the internal heat generation, hardening accelerators are usually limited to repair pours and smaller structures, but can be used in larger structures using the improved, non-calcium accelerators.

2. Benefits

SCC provides improvements in strength, density, durability, volume stability, bond, and abrasion resistance. SCC is especially useful in confined zones where vibrating compaction is difficult (Reference 1). The reduction in schedule is limited since a large portion of the schedule is still controlled by the time required to erect and remove formwork. Although the schedule reduction is limited, it is still sufficient that the reduction in labor costs overcomes the higher material costs.

The direct advantage of HPC to the nuclear power plant construction schedule is the early stripping of formwork. In addition, the greater stiffness and higher axial strength allows for the use of smaller columns in the construction. This will improve the construction schedule by reducing the amount of concrete that must be placed. These factors combined lead to construction elements of high economic efficiency, high utility, and long-term engineering economy (Reference 1).

The high-performance properties of RPC provide many enhancements compared to conventional concrete structures (Reference 3):

- Reduction of structural steel allows for greater flexibility in designing the shape and form of structural members

- Superior ductility and energy absorption provides structural reliability under earthquakes
- Reduction of structural steel allows numerous structural member shape and form freedom
- Superior corrosion resistance

Admixtures and accelerators provide improved concrete properties such as increased strength, reduced weight, or the elimination of flow problems and compaction. With increased strength, the volume of concrete required may be decreased, which in turn reduces the time that is required to pour the concrete. Since the pour time is short compared to the time required to erect and remove forms, the reduction in schedule is limited.

Self-compacting concrete may be especially beneficial when used in combination with steel-plate reinforced concrete structures, which requires a flowable concrete due to the complicated geometries.

3. Code and Regulatory Issues

The present regulatory and building codes permit the use of admixtures in concrete for structures, including structures that are safety-related. The ACI codes include specific rules concerning the use of admixtures and accelerators. As part of the design acceptance, calculations and test data are required to ensure that the concrete satisfies the applicable code requirements.

4. Summary

SCC, HPC, and RPC offer some potential to reduce construction time and costs. Applications have previously been limited to large-scale civil construction projects, mostly internationally, but there has been significant use of HPC here in the U.S. by the Department of Transportation in several states. Concrete admixtures are becoming commonly used and do not require additional testing or analysis. Admixtures are also permitted by the governing codes for concrete construction. No further research support is required for this mature technology, but DOE should inform the industry of this technology through publication of this report and possibly through participation in a conference on advanced construction technologies.

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C

Fiber-Reinforced Polymer Rebar Structures

Traditional reinforced concrete construction uses steel reinforcing bars (rebar) to provide tensile load carrying capability in concrete structures. Steel rebar is generally a cost-efficient method for the reinforcement for concrete. However, steel rebar is susceptible to oxidation when it is not protected by the high alkalinity in the concrete. Further, corroded steel is larger in volume than the original metal. Since concrete cannot sustain the tensile load developed from this volume increase, spalling of the concrete cover over the rebar may occur and lead to further deterioration of the reinforcing steel. The combination of ongoing deterioration and loss of reinforcement properties ultimately requires costly repair and maintenance, and can endanger the structure itself. Additionally, traditional reinforced concrete structures require extensive field assembly during the initial construction phase to place the steel rebar, which contributes to the long construction period.

Although epoxy-coated rebar has an enhanced corrosion resistance compared to standard steel rebar, it is expensive. Recently, composite materials made of fibers embedded in a polymeric resin, known as fiber-reinforced polymers (FRP), have become a corrosion resistant alternative to steel for reinforced concrete structures. Carbon fiber reinforced polymer (CFRP) and glass fiber reinforced polymer (GFRP) are two commercially available alternatives (Reference 4). FRP reinforcement offers tensile strength nearly 3 times that of steel rebar and built-in corrosion resistance (Reference 4). The FRP reinforcement is an economically feasible alternative to steel rebar when the higher strength/weight ratio can be taken advantage of in the design, or when the maintenance of concrete exposed to severe environments, e.g., salt and ice on bridge decks, is considered. General design recommendations for flexural concrete elements reinforced with FRP reinforcing bars are given in ACI 440.1R-01, "Guide for the Design and Construction of Concrete Reinforced with FRP Bars."

1. Implementation Experience

FRP composites have been used in the U.S. for the construction of bridges and external strengthening (Reference 1). In 1996, the nation's first all composite FRP vehicular bridge, No-Name Creek Bridge (Kansas), was constructed. Two similar vehicular bridges are currently being built in Kansas. These structures are constructed using pre-constructed, fiberglass-reinforced concrete panels that only require sealing at the joints to complete the bridge construction (see Figure C-1). This experience offers evidence that the speed of installation and the weight advantages of composite bridges are significant compared to steel rebar reinforced construction.

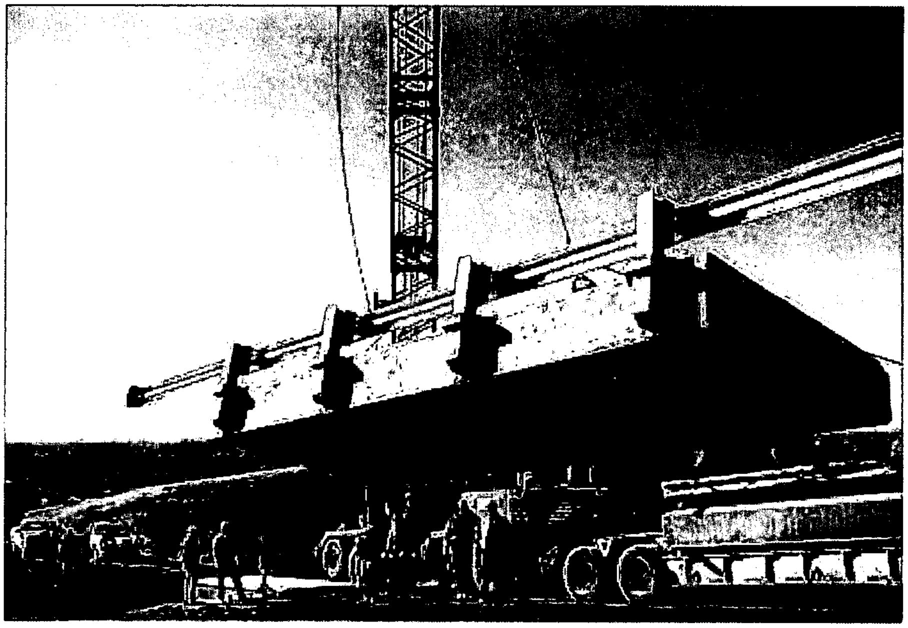

Figure C-1. Pre-Fabricated Fiber-Reinforced Polymer Concrete Panel

2. Benefits

The advantages of FRP are (References 1 and 2):

- High strength/weight ratio
- Long service life due to non-corrosive FRP material (not susceptible to rusting or cracking)

These advantages do not significantly benefit nuclear plant construction. Strength-weight ratio is not an important figure of merit for nuclear plant construction. Service life of steel-reinforced concrete used in existing plants is considered adequate. In addition, the cost of FRP compared to steel is considerable. Specifically, the cost of FRP reinforced concrete is approximately 5 to 8 times the cost per pound of steel-reinforced concrete (References 1, 3, and 4).

3. Code and Regulatory Issues

The present regulatory and building code environment is based on steel rebar reinforced concrete construction (References 5 and 6). Acceptance of FRP rebar reinforced concrete construction techniques in future nuclear plant construction would require resolution of code and regulatory issues, particularly in the following areas:

- Fire-resistance – FRP has a reported susceptibility to deformation or loss of strength when exposed to fire

- Seismic adequacy – Seismic performance of FRP reinforced concrete construction needs to be demonstrated to gain regulatory approval

- Glass fiber reinforced polymer (GFRP) is less ductile than steel rebar and may not be able to with stand extreme loading conditions, such as those found during severe earthquakes and Design Basis Accidents

- FRP reinforced concrete has not been used in past nuclear plant construction and the effects of radiological degradation are not known

- As with other types of concrete composition technologies, analysis or testing will be required to prove that the concrete used during construction meets all required applicable requirements

4. Summary

FRP is not recommended for use in nuclear plant construction. The advantages of FRP, (i.e., high strength/weight ratio and corrosion resistance), are not well-suited to this application. Material costs are also significantly higher than for existing techniques. FRP is more suitable for civil structures which can better utilize its advantages. No actions are recommended for DOE regarding this construction technique. Any proposal to use FRP in nuclear plant construction should be viewed skeptically.

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D

High Deposition Rate Welding

The welding processes used in nuclear power plant construction include:

- Structural welds used to connect structural members
- Pressure welds used to join pressurized components
- Weld cladding (i.e., deposition of weld metal on the surface of another metal to improve the characteristics of the component)

Quality welding, crucial to the construction of nuclear power plants, is time consuming. To shorten the plant construction period, depositing weld metal at the highest rate achievable without jeopardizing quality is desired. The weld deposition rate typically achievable today is higher than the rate achievable during construction of the existing domestic nuclear power plants. Therefore, high deposition rate welding can offer a significant contribution to shortening the construction period for nuclear power plants.

This appendix assesses the status of four common standard welding methods used in large-scale construction projects: gas metal arc welding (GMAW), gas tungsten arc welding (GTAW), submerged arc welding (SAW), and weld cladding.

Gas Metal Arc Welding

GMAW welding, which includes metal inert gas (MIG) and metal active gas (MAG) welding, involves an arc created between a consumable electrode and the base metal. Shielding of the arc from the atmosphere is provided by a gas emitted from a nozzle surrounding the electrode. The standard GMAW welding process is illustrated in Figure D-1.

Several advanced GMAW techniques have been developed since existing nuclear power plants were built in the United States. These techniques include the Rapid Arc and Ultramag processes.

A disadvantage of the gas metal arc welding process is that strict process controls, including extensive work piece preparation and cleaning, are necessary to ensure quality at higher deposition rates.

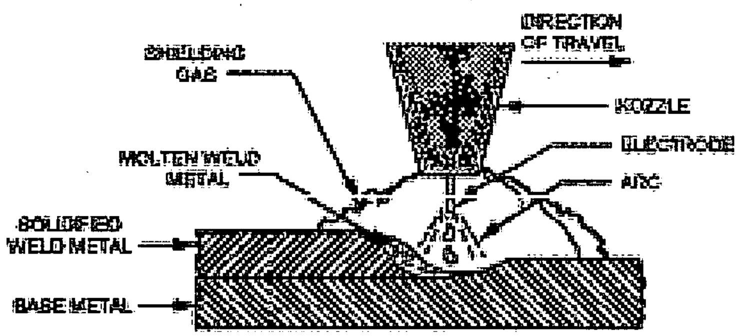

Figure D-1. Gas Metal Arc Welding (GMAW)

<u>**Gas Tungsten Arc Welding**</u>

Gas tungsten arc welding (GTAW), also referred to as tungsten inert gas (TIG) welding, is illustrated in Figure D-2. This process involves an arc created between a non-consumable tungsten electrode and the base metal. Shielding of the arc from the atmosphere is provided by an inert gas emitted from a nozzle surrounding the electrode. A filler metal may or may not be added to the weld pool. GTAW is a relatively slow, high-quality process.

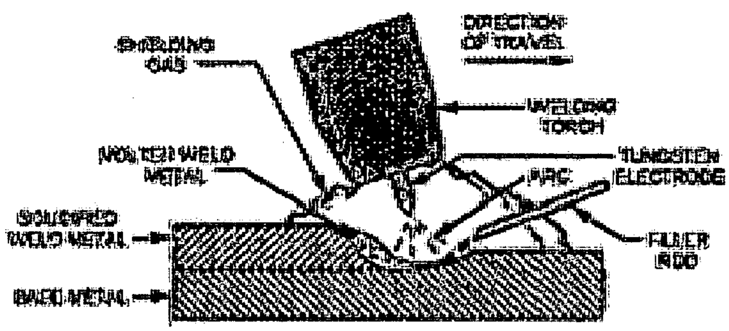

Figure D-2. Gas Tungsten Arc Welding (GTAW)

An automated version of GTAW, known as orbital welding, is now an accepted practice in nuclear applications. Figure D-3 shows a commercially available orbital weld head. Orbital welding offers significant improvements over manual methods for butt welds on piping. Some problems associated with manual GTAW are difficulty in controlling process variables to achieve desired quality and difficulty in accessing weld locations. Both of these problems tend to slow the construction process and increase cost.

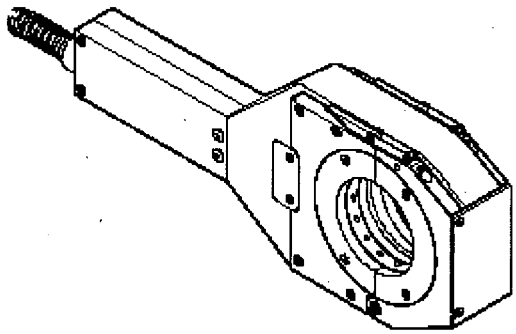

Figure D-3. Swagelok Orbital Weld Head

Submerged Arc Welding

SAW, or submerged arc welding, involves a consumable electrode that provides filler metal and shielding. The standard SAW process is illustrated in Figure D-4. The arc between the consumable electrode and the base metal is shielded by the gas generated by the melting and re-deposition of the flux coating the electrode. The flux floats to the outside of the deposited weld metal covering it and providing additional protection.

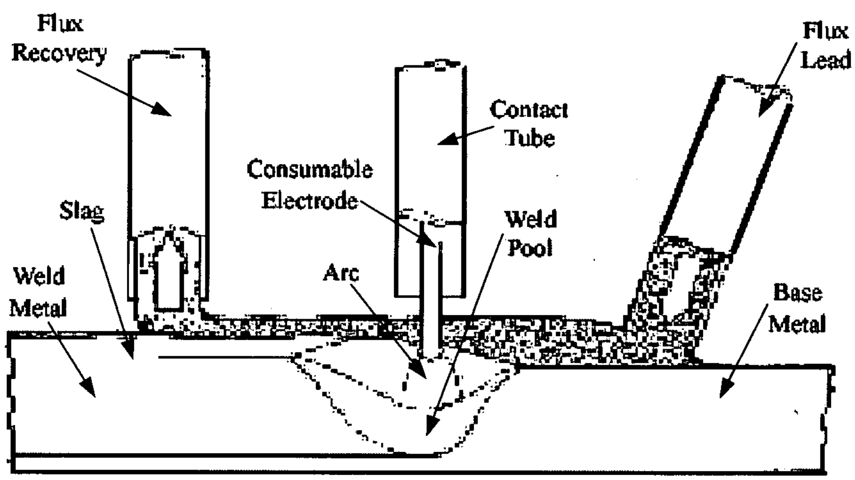

Figure D-4. Submerged Arc Welding (SAW)

An improvement to the SAW process is the technique of multiple wire welding. This process involves more than one consumable electrode producing an arc and contributing to the same weld pool. Multiple wire welding provides an increase in deposition rate due to the higher rate at which heat and weld metal are added in the process.

SAW with flux-cored wire is a high deposition welding technique whose potential has not been fully realized (Reference 1). Flux-cored wire is used as the consumable electrode in the process. The flux is contained at the core of the wire. The use of flux-cored welding significantly mitigates the major shortcomings of subarc welding, which are:

- The mechanical properties that can be obtained at high deposition rates
- Sensitivity to base metal surface impurities (e.g., rust, moisture, etc.)

A disadvantage of the SAW process is the additional cost due to the large amount of flux cleanup required.

Weld Cladding

Weld cladding involves deposition of weld metal over the surface of another metal. Different methods have been used for this purpose in nuclear power plant construction. The earliest method was the attachment of sheet metal over the base metal. In the late 1980s, the technology for internal cladding for in situ vessel applications was still based on equipment designed in the 1950s (Reference 3).

Strip clad welding is a process that provides high quality weld cladding with weld deposition rates at least three times faster than those achieved by current technology (Reference 4). This process, developed for internal cladding of piping and pressure vessels, involves the use of relatively wide strips of filler material. The cladding can be applied in situ in either a horizontal or vertical orientation. Either a submerged arc or electroslag welding process is employed to join the strip cladding to the base metal.

A prototype process for vertical strip cladding was developed in the late 1980s, as shown in Figure D-5. In the process illustrated in Figure D-5, the weld pool, flux, and slag are supported by a ceramic "hot top." A water-cooled copper shoe supports and cools the weld metal as it solidifies into a solid strip. The electrode (filler material) is fed as a strip (also referred to as a ribbon) instead of as wire form.

1. IMPLEMENTATION EXPERIENCE

Gas tungsten arc welding has been used in Japan to narrow-gap-weld a cylindrical pressure vessel, or shroud, to existing shroud supports with minimal heat input (Reference 5). The process was also used to manufacture the shrouds in the shop.

Orbital welding is commonly used for high quality butt welds on piping. It can be used on a broad range of pipe sizes. The equipment is commercially available and has been used in many industries. In the aerospace industry, a single aircraft can contain more that 1,500 welded joints, all automatically created with orbital equipment. The pharmaceutical industry uses orbital welding in their process lines and piping systems to make quality welds that will ensure water through the tubes is not contaminated by bacteria, rust, or other contaminants. The nuclear industry also currently uses orbital welding for producing piping welds.

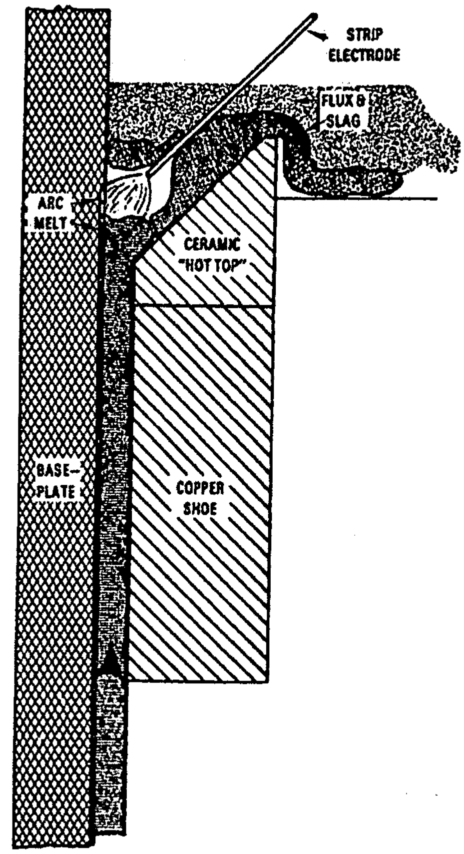

Figure D-5. Vertical Strip Cladding (adapted from Reference 3)

SAW is commonly used in steel fabrication for structural shapes, and longitudinal and circumferential seams for pipes, tanks, and pressure vessels of large diameters. Typically, steel plates with thicknesses of 1-in or greater are welded using this process. SAW processes readily weld low-carbon, low-alloy, and stainless steels, but not high-carbon, tool steels, or most nonferrous metals.

Using SAW is traditionally limited to the horizontal position because of the gravity feed of the granular flux. Therefore, when the need for a weld in the vertical position is required, positional welds are usually carried out manually or semi-automatically. Because this method is so time consuming, recent technology has led to submerged arc welding in the vertical position with horizontal electrode feeding. This method is used in shipbuilding, where the joining of large ship sections requires long and mostly straight weld seams in the vertical position under yard conditions. Good mechanical-technological properties of the welded joints are attainable with deposition melting rates of over 4.5 lb/hr.

SAW using gantry units is also used in the construction of various civil structures. Gantry welding units are structural-type frames allowing bidirectional, automatic, or semiautomatic travel. Typically, the welding control units, torches, and power sources are mounted permanently on the unit. A qualified welder can perform vertical-up welding. Gantry welding units can make 5/16-in. horizontal fillet welds at 36 to 40 inches per minute (IPM) in flange-to-web girder welding (approximately 6 ft. of deposited fillet weld per minute). Using this system, fabricators can produce more than 300 ft. of welded girder a day.

SAW with flux-cored wire is being used in field construction of nuclear power plants in Japan. Strip clad welding has been used in the construction of nuclear components overseas.

2. BENEFITS

Advanced GMAW techniques, which include the Rapid Arc and Ultramag processes, have achieved deposition rates of 33-37 lbs/hr in certain applications. Deposition rates as high as 66 lb/hr can be achieved under special circumstances (Reference 1). Typical weld deposition rates are in a range of 4-20 lbs/hr (Reference 2).

The orbital GTAW welding process is an automated welding process. This makes controlling process variables easier and facilitates achieving a consistent and high level of quality. The relatively small size of the orbital welder allows it to be used in locations were personnel access is difficult or impossible. Productivity rates are improved over manual methods because setup is easier and less rework is required. The deposit rate of the orbital process is approximately 1.6 lb/hr. In addition, the relative ease of the welding technique eliminates the need for the skilled welders required with standard methods. Orbital welding is an attractive option for use in construction of a new nuclear power plant in the United States.

For several decades, SAW has been the preferred high deposition rate welding process in many industrial applications (Reference 1). In 1996, deposition rates as high as 33 lbs/hr were reported for standard single wire (i.e., single consumable electrode) subarc welding. For a multiple wire process, deposition rates as high as 100 lbs/hr were reported (Reference 1). SAW used in vertical applications has achieved a disposition rate of approximately 4.5 lb/hr. For comparison, weld processes used in domestic nuclear plant construction were classified as high deposition rate methods when the weld metal was deposited at a rate exceeding 11 lbs/hr (Reference 2). Structural members can be assembled for civil applications using gantry units at rates of 6 ft/min versus a typical rate of 20 in/min.

Flux-cored wire, although having higher material costs, provides significant cost savings due to the associated productivity improvements.

Based on a demonstration performed in 1999, the deposition rates for Strip Clad Welding exceed those of GTAW and SAW. This demonstration also showed superior control of process parameters. A similar demonstration performed in 2000 deposited a total of 486 lbs of weld metal at rates of 26-28 lbs/hr. This weld deposition rate is approximately thirteen times that achieved with GTAW and three times that achieved with SAW.

Subsequent tests indicated superior mechanical and metallurgical properties for cladding applied by Strip Clad Welding. Exceptional tensile and toughness properties were demonstrated for the weld itself, and cross-weld properties (including base metal, heat-affected zone, and weld) were determined to be good. Additionally, the stress profile was noted to be encouraging. Improvements on these characteristics are anticipated in real-world applications.

3. Code and Regulatory Issues

Federal regulations require welding procedures and personnel to be qualified in accordance with applicable codes. Pressure welds are typically required to meet the ASME code and structural welds are typically required to meet the American Welding Society (AWS) code. These standards further require that a welding process be qualified for nuclear grade applications. A novel welding process must be capable of producing welds that have sufficient mechanical properties, and must be capable of demonstrating those properties in testing. In addition, the personnel operating the equipment must also demonstrate that they are trained and competent in the use of the novel technique.

Qualification activities are carried out by the vendor in the field prior to their use. Since each of the technology advances has been demonstrated, their qualification for domestic use is not expected to be a challenge. In addition, several commercially available orbital welding systems have previously been qualified domestically for use in repair of nuclear grade components.

4. Summary

Five technology advances were identified that offer significant potential toward reducing construction period: high deposition rate gas metal arc welding, orbital welding, flux cored submerged arc welding, vertical submerged arc welding, and strip clad welding. Orbital welding and high deposition rate gas metal arc welding are mature and commercially available technologies. Flux cored submerged arc welding, vertical submerged arc welding, and strip clad welding have been demonstrated. Vertical submerged arc welding could potentially be useful in assembling steel-plate reinforced concrete structures in the construction of a new nuclear plant.

No research and development is required. However, DOE should inform the industry of the technology advances in high deposition rate welding through publication of this report and possibly through participation in a conference on advanced construction technologies.

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E

Robotic Welding

A modern robotic welding system is illustrated in Figure E-1. This technology is the most flexible version of automated welding. It involves automated control of the weld head position and the option of automatically controlling certain welding parameters. A typical system consists of a weld head, robot, user interface, and power supply. Robotic welding can be used with most types of welding processes including gas metal arc welding (GMAW), gas tungsten arc welding (GTAW), flux cored arc welding (FCAW), and submerged arc welding (SAW).

Automated welding processes can be divided into two categories: fixed and flexible. Fixed automated welding involves expensive equipment for holding and positioning weldments. It is used for simple weld paths and high volume production. Flexible automated welding involves relatively inexpensive and simple equipment for holding and positioning weldments and can be more easily adapted to complex weld paths. It is suitable for low, medium, or high volume production. Robotic welding is flexible enough to be used as a direct replacement of some difficult manual welding operations.

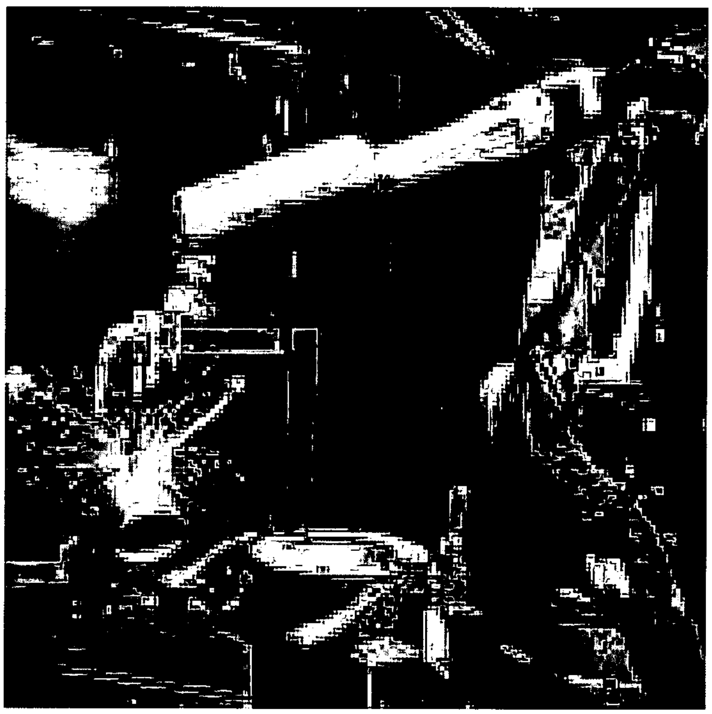

Figure E-1. Modern Robotic Welding System

Set up activities are required to use a robot in a new welding procedure. The setup includes tooling arrangement and software programming.

1. IMPLEMENTATION EXPERIENCE

In traditional large-scale construction projects, such as nuclear power plant construction, the majority of the welding operations are performed in the field. Field welds are commonly difficult to access with a robotic welding system. In addition, many field weld procedures are repeated only a few times (i.e., small series production). Only processes that require minimal setup time can take advantage of robotic welding systems. This is demonstrated in the construction of fossil power plants where field welds are performed either manually or using automated processes not involving robots (Reference 1).

Modern, multi-unit, modular construction projects benefit from robotic welding systems. These benefits include the following:

- Increased productivity for large series production
- Improved productivity for small series production over early robotic welding systems
- Suitable for shop applications that are typical of modular construction techniques
- Suitable for complex or simple weld paths
- High level of control over welding process parameters
- Compatible with automated quality control processes

Robotic welding systems are commercially available for use in many industrial applications. Robotic welding has been applied extensively in assembly-line applications, such as automobile fabrication. Robotic welding has been applied in shop construction of nuclear power plant components in Japan.

2. BENEFITS

Robotic welding is most suited for shop work where there is a controlled environment and processes are repeated many times (i.e., large series production). As robotic welding systems become increasingly more flexible, they are also useful in small series production applications. Modern construction techniques, which are more modularized and involve increasing amounts of shop fabrication, are well suited for robotic welding. However, this does not reduce the on-site construction duration since shop work is not critical path.

Quality control of welds on nuclear components is time-consuming. One technique that offers cost savings is automated quality control. Robotic welding is compatible with automated quality control techniques and could facilitate their introduction. This benefit is primarily in cost reduction and not schedule reduction and is therefore not discussed in detail in this report.

Employing robotic welding for repetitive welding procedures is estimated to increase productivity by a factor of three over manual welding (References 2 and 3). In applications where a welding robot replaces manual welding, a return on investment is typically achieved in about one year (Reference 3).

3. CODE AND REGULATORY ISSUES

Federal regulations require welding procedures and personnel be qualified in accordance with applicable codes. Pressure vessel welds are typically required to meet the ASME code, and structural welds are typically required to meet the American Welding Society (AWS) code. These codes generally require that a welding process be qualified for nuclear grade applications.

Appropriate tests will be required to show that robotic welding is capable of producing quality welds. Weld strength may be different for automated welding than for manual welding (Reference 4). Corrosion resistance may also be affected. In addition, procedures must be developed for demonstrating that the personnel operating the equipment are trained and competent in the use of the robotic welding system. Software used with robotic welding does not require NRC acceptance beyond acceptance of the weld produced.

Robotic welding is relatively mature and demonstration of acceptable welds is expected. Robotic welding has been applied in shop construction of nuclear power plant components in Japan. Therefore, pending qualification, the process is likely suitable for nuclear construction in the U.S.

4. SUMMARY

Robotic welding offers cost savings through increased productivity and reduced rework for certain shop applications. As more construction activities are moved out of the field and into the shop, robotic welding becomes increasingly beneficial for large-scale construction applications. However, the main benefit of robotic welding is cost reduction and not construction schedule improvement. Robotic welding has been applied in shop construction of nuclear power plant components in Japan.

No research and development is required. However, DOE should inform the industry of the technology advances in robotic welding through publication of this report and possibly through participation in a conference on advanced construction technologies

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F

3D Modeling

Solid, three-dimensional (3D) modeling software is used in contemporary facility design to provide three-dimensional layouts of the proposed facility. 3D modeling software allows for greater visualization of a project. It is the standard approach for plant engineering. This type of modeling has replaced much of the physical 3D modeling used to support the construction of domestic nuclear generating facilities. Benefits of 3D design occur in all stages of the completion of a plant: conceptual design phase, engineering and detail design phase, construction phase, and operations and maintenance phase. Figures F-1 and F-2 show examples of 3D models. Significant detail, including stairways and platforms has been included in the solid model shown in Figure F-1.

The process of using 3D design software to design a power plant starts with generating a solid model of the plant components. A solid model is a 3D computer-generated model of the components in a system. After the solid model is completed, the 3D design software is used to automatically generate the various plan, elevation and detail views needed to fabricate the plant. There is typically a relationship between the drawings and the model such that any changes made to the model are automatically updated in the drawings and vice versa. In addition to providing a 3-dimensional entity that designers can use to assess spatial relationships between components and structures, the solid model provides all of the dimensional data for the plant in a single database. This approach greatly increases efficiency and reduces the potential for errors.

Future applications of 3D modeling include the possibility of full-scale virtual reality modeling. Japanese vendors are currently experimenting with using a virtual reality environment to move around a virtual plant, trace out coordinates, add or remove components, and track actions. This technology will likely not be ready for use until after 2010.

Figure F-1. 3D Model of Paper Coating Line

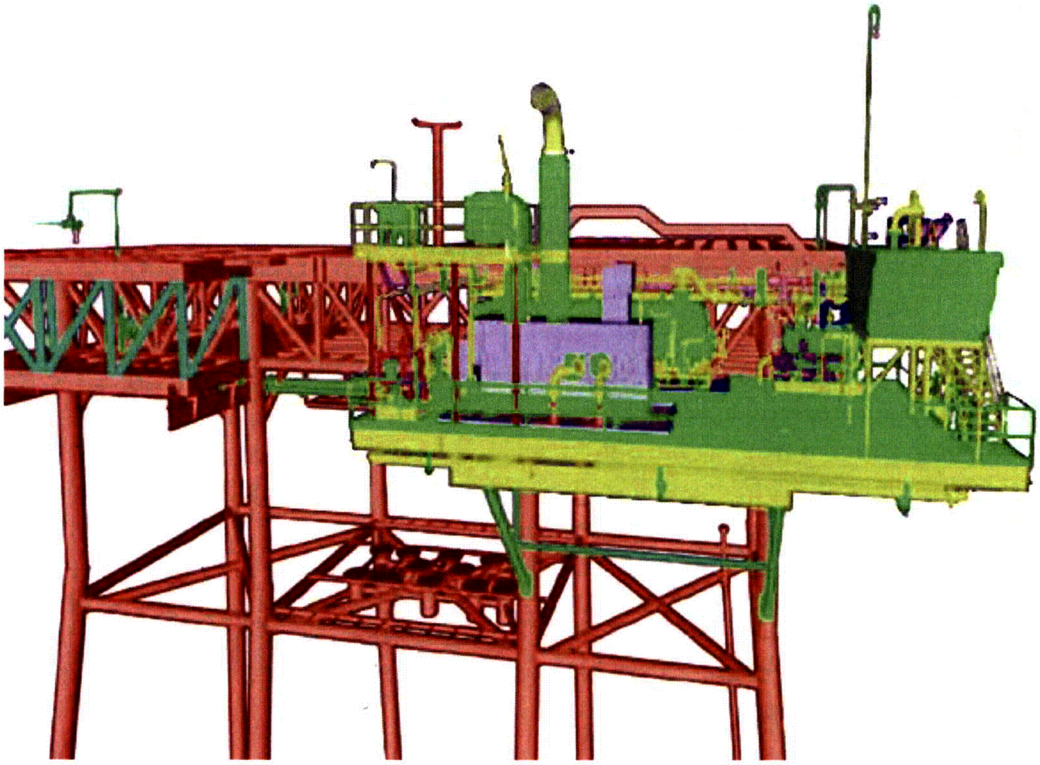

Figure F-2. 3D Model of Offshore Platform

1. IMPLEMENTATION EXPERIENCE

The benefits of the 3D design process are not limited to the design and construction of the plant. Many nuclear plants not designed using 3D processes have generated 3D plant models to increase efficiency of maintenance and outage activities. NSSS vendors and A/E firms have roughly equal capabilities with 3D modeling and can be expected to use this technique based on the reduction in the construction cost. The Oyster Creek Nuclear Plant in New Jersey uses a 3D model of the refueling floor to coordinate, evaluate, plan, visualize, and sequence refuel floor outage activities. The model is also used to generate detailed drawings of the refuel floor during each of the various processes. Use of this model optimizes these processes and reduces outage time. TVA's Browns Ferry in Alabama, another 1970 vintage plant, is evaluating the development of a 3D model which will be tied to the equipment databases. Users could navigate through the 3D model, and, by selecting various components with a click of the mouse, can access the pertinent component design information.

2. BENEFITS

3D design technology offers many benefits during the construction of the plant. A large cost savings resulting from using 3D design software is the reduction in rework labor and materials. Field rework labor can cost as much as 12% of total construction labor when using manual methods of design (Reference 1). Due to better visualization of the project and completion of interference checks prior to construction, this number can be reduced to 2% (Reference 1). 3D plant design systems also provide a means to determine job sequencing and craft work, leading to compressed construction schedules. Using the 3D models to convey the plant layout and design visually improves construction sequencing. Off-site fabricators can also get a clearer understanding of their work from the 3D models, minimizing the possible errors made in reading traditional isometric and orthographic views.

3D design programs include databases of the plant design that can produce bills of material and material take-offs automatically. This provides more accurate procurement of parts and materials needed for the construction of the plant. This reduces the amount of material surpluses, and thus reduces the project expenditures.

During the conceptual design phase of a project, 3D design processes can be used to facilitate the economic analysis of alternative plans before project costs are committed. As much as 80% of project costs are committed during a conceptual design phase (Reference 1). By using 3D design processes, designers can complete designs sooner. They can also change the design more efficiently when evaluating design alternatives. The design plans created using 3D design software are easier to interpret and more accurately communicated. This contributes to improved quality and timeliness of a project. Design changes can be made quickly, and all components are updated automatically. All of the physical plant drawings can be easily produced from the original model. Another benefit gained when using 3D design is the ability to communicate design information to non-technical personnel.

There are many advantages of using 3D design software in the engineering and detail design phase. These benefits include improved quality, consistency and standardization of the design, constructability analysis, automated interference checking, improved overall efficiency, and enhanced project control and coordination.

While developing 3D models can be more expensive on an hourly basis than producing similar 2D drawings, the time saved in other areas of design can provide 5% to 10% in overall engineering cost savings (Reference 1). 3D design usually reduces errors and generates higher quality designs than 2D methods. The 3D software incorporates specifications and code requirements in a database which helps to avoid expensive mistakes by recognizing errors and designs not meeting specifications. 3D models can be combined with analysis tools to test the design for mechanical stress, hydraulic analysis, thermal stress, and other factors.

The larger and more complex a system is, the greater the potential savings from using 3D design software. The 3D models help check and fix interference between different design areas, such as piping, electricity, and HVAC. The ability to use 3D design software to evaluate spatial details makes future maintenance easier.

3D design also helps streamline the hazard and operability review (HAZOP) process. Due to the enhanced visualization offered by a 3D model, the time it takes to review a plant can be reduced by one-third. The 3D models improve the quality of the review and the operability assessment.

Recently, 3D models have also been used in the operations and maintenance phase. Maintenance crews can use 3D models to familiarize themselves with work areas. This allows them to plan in advance the placement of electrical or welding outlets, eye wash stations, safe routes, and other activities, thus making the entire process more efficient.

3. Code and Regulatory Issues

Requirements for the preparation of a 3D model and drawings are governed by ASME Y14.41-2003. These standards also provide guidelines to improve modeling and annotation practices when using computer aided design software.

4. Summary

The use of 3D design software in the design, engineering, and construction of a plant can potentially reduce costs and construction schedule, and increase quality and efficiency. The 3D models can help communicate the design to both technical and non-technical personnel. The increased visualization of the project design can help reduce field rework and minimize material and labor costs. Creative use of the model after construction to support operation and maintenance activities can also offer significant benefits. Scheduling and cost analyses are facilitated with 3D plant design systems. DOE should inform the industry of these technology advances in the use of 3D design and engineering through publication of this report and possibly through participation in a conference on advanced construction technologies.

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G

Positioning Applications in Construction (GPS and Laser Scanning)

Global Positioning System (GPS) is a worldwide radio-navigation system formed from a constellation of thirty-two satellites orbiting the earth (Reference 1). This system is shown pictorially in Figure G-1. Based on the measurement of the time it takes for radio signals to travel from the satellites to a ground receiver, the receiver calculates its own location in terms of longitude, latitude, and altitude. GPS was created by the U.S. Department of Defense (DoD) in 1973 and declared fully operational in 1994. While it was originally developed for military purpose, it is now available to civilian users free of charge.

GPS has several applications related to the construction and operation of power plants. The applications identified include:

- Site surveys
- Control of earth moving equipment
- Tracking of equipment and material
- Measurement of structural deformation and alignment
- Indoor as-built measurements with laser GPS

A receiver requires signals from four or more satellites at the same time to calculate position, velocity, and time. The receivers automatically choose the satellites that will produce the best estimate of location among the satellites that are in view. Since a line-of-sight to the sky is required, GPS is inappropriate indoors, in areas of dense vegetation, next to tall buildings, and under bridge structures.

The accuracy of measurements is affected by natural phenomenon, electrical failure of elements, and intentional disturbances. The Department of Defense can deliberately downgrade the accuracy of the GPS satellites signals through a process called Selective Availability (SA). They reduce the accuracy available to unauthorized users in times of war or for military action. Authorized users may obtain encrypted information to make corrections so that accuracies are not affected during these times. Other sources of error include clock errors, satellite orbital errors, travel delays through the ionosphere and refraction through the troposphere, and signal reflection off of buildings and lakes. Data processing techniques have been developed to minimize the effects of these errors.

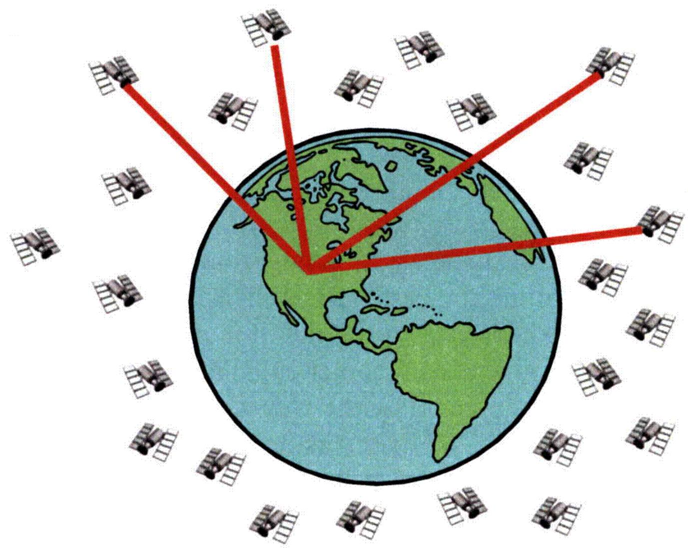

Figure G-1. Global Postioning System Pictoral Representation
(Thirty-Two Satellites Orbiting Around the Earth)

1. Implementation Experience

Research into using GPS in construction has been performed by the following organizations:

- United States Army Corps of Engineers
- Construction Industry Institute with Purdue University
- National Institute of Standards and Technology
- Transportation Research Board of the National Research Council
- Most State Departments of Transportation

Most state departments of transportation have purchased GPS equipment within the past several years and are using the systems to perform surveys, assess inventory, and produce maps. Industrialized countries outside of the United States are using GPS similarly.

GPS technology from Trimble Navigation Ltd. and Leica Geosystems Inc. has been used to survey and move earth for roads, airport runways, shopping malls, residential housing, and business parks. Associated software calculates labor, material, and schedule requirements.

Indoor GPS technology, using lasers rather than satellites, has been used in the general construction industry to position walls, ceilings, and floors quickly and accurately. Also, laser technology has been used to align pipe for underground utilities. The most advanced application of indoor GPS has been its implementation in the construction and inspection of aircraft.

GPS equipment used on a construction site includes:

- GPS receivers – On a new construction site, one receiver is set up on a permanent base mounting with an antenna and serves as the reference station. Other receivers are allowed to move around the site and are "roving" receivers. The signals of the roving receiver are corrected by errors calculated at the stationary reference receiver whose position is accurately surveyed and well known

  Stationary reference receivers have been established across the country by government agencies and are available for public use, sometimes making the installation of a site reference station unnecessary.

- Computer – The computer takes the GPS data and translates it into a site plan

- Radios – Information is relayed between receivers and other equipment on the site by a high speed radio network

A single mobile GPS receiver, a roving receiver without a stationary base receiver, is accurate to about 10 yards. If differential GPS is used (DGPS), the receiver is supplied with corrections derived from a GPS base station within 200 miles and the accuracy improves to better than 3 ft. If real-time kinematic GPS is used (RTK GPS), the GPS receiver has more processing power and it is supplied with real-time data from a base station within 13 miles such that the accuracy becomes better than 0.1 ft.

Conversion to GPS requires a substantial initial capital investment that can outweigh the investment in equipment for one-time use applications. Theodolites and alidades tend to be less expensive and more durable than their electronic counterparts. The decision to use GPS is a function of time, cost, required degree of accuracy, availability of equipment, and the design or construction phase involved. An RTK GPS system can cost around $60,000 for a single base unit and one rover (Reference 1). Additional rover units cost around $25,000 each. Less accurate units can be purchased for under $10,000.

Most vendors offer training courses on how to use their equipment. Mastering the GPS unit takes approximately 6 months to a year for a trained surveyor. The greatest amount of training involves learning and understanding the potential sources of error.

2. BENEFITS

Application of GPS technology to field construction has many potential benefits including those discussed below.

Surveying

A primary benefit of GPS surveys versus traditional surveys is reduced costs associated with decreased labor and time requirements. However, to ensure time is saved, a controlled method of planning, organizing, and conducting GPS surveys is required to efficiently and effectively use the large volume of data that is collected.

Another benefit often gained is increased measurement accuracy. Human error is reduced since readings are recorded electronically with minimal human interaction other than selecting the location and typing in the description of the point. A GPS system can record points at least four times faster than conventional methods. Redundancy in some of the measurements provides a means to check the results.

For survey work, a geodetic-quality GPS receiver with centimeter-level accuracy is required (RTK GPS). Industry standards are two centimeter of accuracy for real-time horizontal GPS surveys, exceeding accuracy of conventional methods by a factor of 5 or greater. Vertical accuracy is approximately four centimeters, about the same as traditional methods. GPS may not be accurate enough for the final grade check of surfaces and may require the use of leveling to supplement the GPS established control.

Field operations to perform a GPS survey are relatively easy and can generally be performed by one person per receiver, with two or more receivers required to transfer control. Conventional survey work is generally accomplished using a two or three-person survey crew. According to a National Cooperative Highway Research Program report, common labor reduction ratios for GPS as compared to traditional survey methods are nearly 6:1 for horizontal surveys and 10:1 for elevation surveys (Reference 1).

Another time-saving advantage of GPS is its long-range capability. Once a GPS system is established, measurements can be taken within a 6-mile radius of the base reference station whereas conventional methods would require the surveying equipment be moved about every 600 ft.

As a job progresses, additional surveys are needed to gather more information, to make design changes, and to document completed work. This conventional process is time-consuming and contains numerous opportunities for error. With GPS, the data can be collected in real-time and used to modify plans or a digital terrain model on computers that are in the field.

Earthmoving

Earthmoving equipment, such as bulldozers, motorgraders, scrapers, excavators, can be fitted with GPS receivers and computers that direct operators on the removal or placement of fill dirt to meet the planned site design. Use of GPS eliminates the need for survey stakes to guide the workers. Site design information, in the form of plans or a digital terrain model developed based on a GPS survey data, is downloaded to the on-board computer on the earthmoving equipment. The computer calculates where the machine is and how much cutting or filling is needed by referring to the site grid and the base reference station. The computer makes the decision based on GPS data of the blade location. The information is transmitted to the operator via a monitor or light bars. Instead of being controlled by an operator, the system can be configured so the equipment is automatically controlled via a controller supplied with real time GPS data. Figure G-2 illustrates the use of GPS in earthmoving.

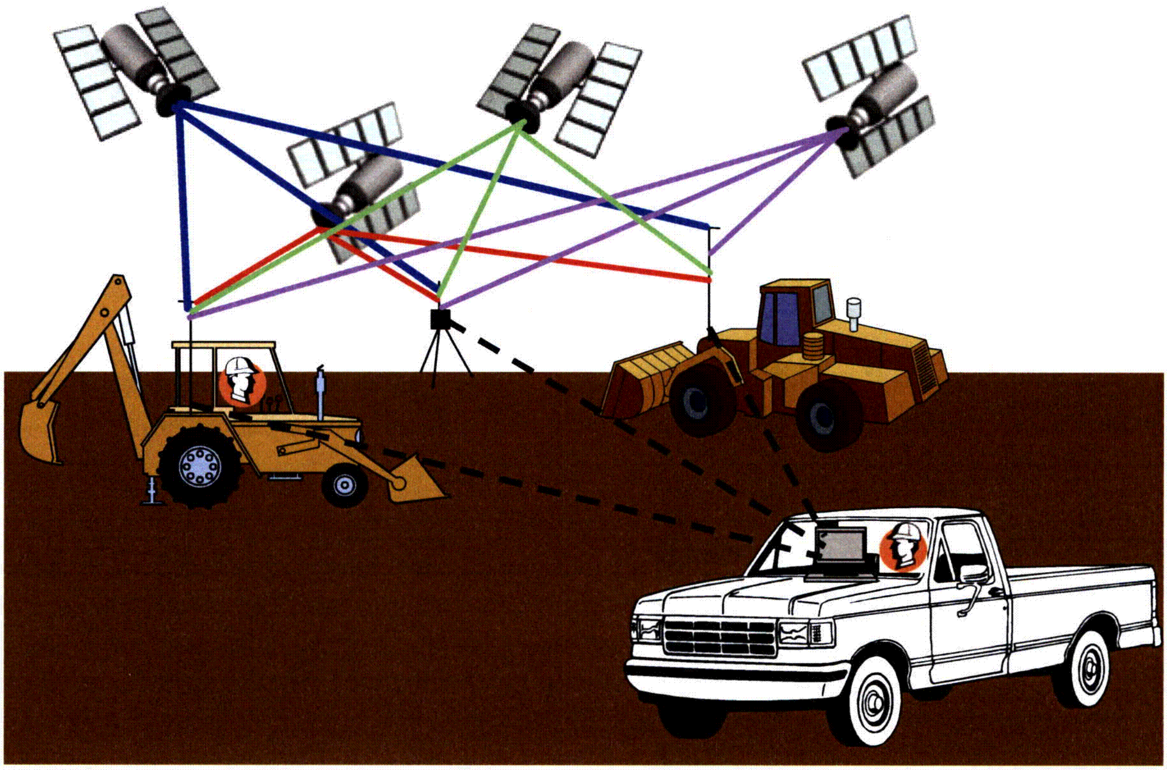

Figure G-2. GPS Information Tracking During Site Land Development

Another advantage of GPS is real-time site monitoring. Progress can be updated by the wireless computer network in real time, allowing the site supervisor to check progress on a computer in the cab of his/her pick-up truck.

In summary, the benefits in applying GPS in site-preparation are as follows:

- Fast and accurate decision and control due to real-time information of position and grade
- Reduction of surveying and grade checking costs and increase of machine utilization
- Faster job cycle - Operators know where the grade is, as well as the locations of design elements, and are able to move more dirt each day. They can work regardless of wind, dust or darkness, finishing jobs faster with less fatigue
- Reduction of rework caused by the lack of correct information in the field

Material and Equipment Tracking

GPS can be used to keep track of construction inventories and equipment location. Since less accuracy is required, less expensive units with meter level accuracy can be used. Man-hours for inventory checks can be reduced and checks on inventory can be performed from a central location or from anywhere on the job-site. It is estimated that a resource grade unit with accuracy on the order of a meter can be purchased for about $10,000 (Reference 1).

Measurement of Structural Deformation and Alignment

GPS techniques can be used to monitor the motion of points on a structure with respect to static structures. This is accomplished with an array of antennas placed on the structure and the static reference structure. Measurements can be made on a continuous basis or on a periodic basis. Measurement precision on the order of 2 to 5 mm is typical (Reference 6). This type of measurement may be used to measure foundation settlement or it may aid in assembly of large structures fabricated off-site.

Indoor Measurement Tools

GPS satellite signals cannot be received inside buildings. Instead, an infrared laser technology that is computationally similar to GPS can be used indoors (Reference 5). This infrared laser technology is often called Indoor-GPS though it employs a localized signal transmission system as a substitute for the global satellite network.

The indoor system requires the set-up of several infrared laser transmitters that send light signals over the area in which position information is desired. During set-up, the relative position and orientation of the transmitters is determined through infrared measurement. When operating, a stationary or roving receiver picks up the infrared signals from at least two transmitters that are in its line of sight. The receiver processes the signal information to calculate its own position based on the known positions of the transmitters. Use of multiple transmitters increases the accuracy of the position calculations. Accuracy on the order of several mils is possible.

Indoor-GPS is used to position large parts for mating, keep track of equipment position and movement, and track part inspection. Inspection and construction tools can be instrumented with GPS technology to do such tasks as keep track of which bolts have been tightened and with what torque.

Benefits of indoor-GPS are greatest when a particular set-up can be reused multiple times. For example, the aerospace industry has found indoor-GPS particularly useful in its manufacturing facilities where it is used for the assembly and inspection of multiple aircraft (Reference 5). Arc Second, Inc. is a major developer of indoor GPS with its Constellationellation^{3D-I} technology.

In the construction business, infrared technology has primarily been used for surveying purposes and the placement of walls, ceilings, and floors. However, infrared technology has the potential to be a powerful time-saving tool for recording as-built measurements in new nuclear power plants. Furthermore, it can aid the construction process by guiding the placement of equipment and tracking inspections.

3. Code and Regulatory Issues

No issues were identified. In addition, none are expected since the accuracy of GPS surveying methods meets or exceeds that of traditional methods.

4. Summary

GPS technology is currently used to survey, move earth, and grade work-sites. Indoor GPS technology, using lasers rather than satellites, is also available for indoor surveying purposes. These applications are well developed and in current use in the transportation, housing, and office building construction industries. Indications are that they provide significant cost and time savings over traditional techniques. As long as equipment and trained personnel are available, construction of a new nuclear power plant would benefit similarly.

GPS has additional potential benefits to new nuclear plant construction that could be used for plants planned for the generation beyond 2010. These potential benefits include:

- Accurate and time efficient placement of equipment and large structures
- Automation of drawing revisions
- Material and equipment tracking off-site and on-site
- Robotic inspection of critical components
- As-built measurement of piping and equipment

As this technology is being pursued aggressively by industry, DOE-sponsored research and development will probably not be required to enable its use in nuclear plant construction. DOE should inform the industry of technology advances in positioning and measurement applications through publication of this report and possibly through participation in a conference on advanced construction technologies

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H

Open-Top Installation

In previous domestic nuclear power plant construction, the as-built construction schedules from first concrete (FC) to fuel load (FL) were long and few tasks could be completed in parallel. In the open-top installation construction sequence, part of the Reactor Building is built, followed by placing the Reactor, Steam Generators, and other large pieces of equipment in place in the building using large cranes. Once the equipment has been placed inside, the construction of the Reactor Building can be finished while other site workers install piping and electrical systems. Figure H-1 illustrates the open-top installation process.

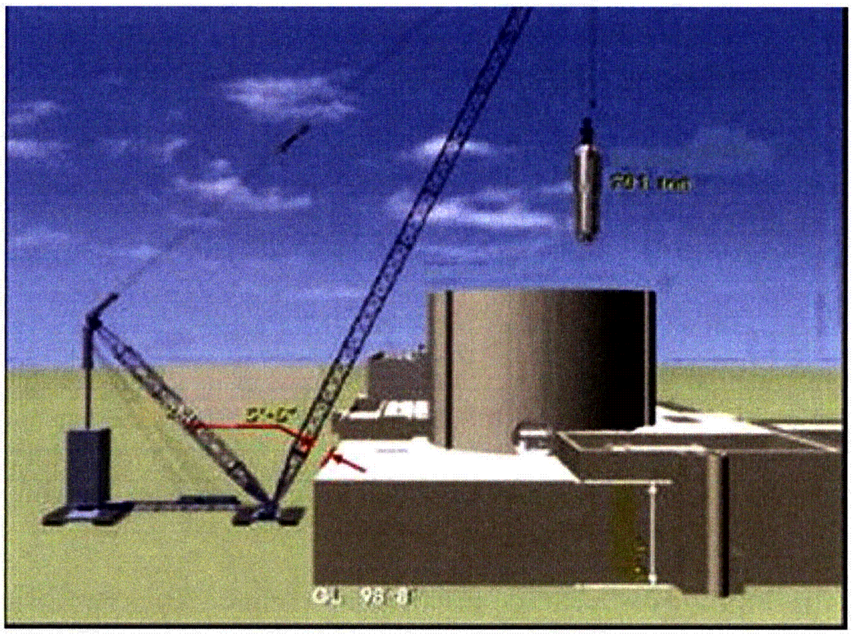

Figure H-1. Open-Top Installation

Since the last generation of plants built in the U.S., the load capacity and reach of cranes has been increased, leading to cranes known as Very Heavy Lift (VHL) Cranes. These cranes are capable of lifting and moving modules weighing up to 900 tons and reaching several hundred feet. The advent of these cranes permits very heavy loads to be placed. This has extended the feasibility of Open-Top construction and allows large-scale use of techniques such as modularization.

1. IMPLEMENTATION EXPERIENCE

This method is used in large-scale construction projects, including nuclear power plants recently completed or under construction in Japan, Taiwan, and China. Using Open-Top Installation and Modularization techniques, these plants have been built in less than 72 months. As a result, construction costs have been reduced 10 to 20%, or approximately $100 million (Reference 2). It is expected that these costs will further decrease as industry experience is gained in using Open-Top Installation in combination with modularization.

2. BENEFITS

There are significant advantages in cost and schedule using Open-Top Installation. It is estimated that Open-Top Installation in combination with modularization techniques can shorten the construction schedule from 10 to 15 years to as few as 4 to 5 years from first concrete to fuel load (Reference 2). Even limiting the use of this technique to the installation of major components can save massive amounts of time.

3. CODE AND REGULATORY ISSUES

There are no identified codes or regulatory issues pertaining to the use of Open-Top Installation. As long as the installation, fabrication, and inspections meet the applicable codes, the construction process does not affect the structure.

4. SUMMARY

There is significant potential for savings in schedule and cost using Open-Top Installation in power plant construction. A review of the regulatory codes and standards has not identified any issues which may affect current rule-making. Open-Top Installation in combination with modularization has been employed in the construction of several plants internationally with great success in cost and schedule reduction.

In order to take full advantage of Open-Top Installation, reactor vendors and construction companies will need to ensure that the design and construction schedule of the plants support Open-Top Installation and modularization. Also, depending on the climate at a site, a constructor should consider installation of a moveable roof to allow work inside the open containment to proceed in all weather conditions.

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I

Pipe Bends vs. Welded Elbows

Domestic nuclear power plants were constructed using welded pipe fittings, such as elbows, in piping systems throughout the plant. Extensive construction materials and labor are required at the construction site to support this type of piping system construction. This method contributes to the long construction period typical of large-scale field constructed projects. Pipe bending is a simple alternative construction technique that can speed up piping system construction and reduce the number of workers required.

Pipe bending technology was available 20 to 30 years ago when the existing domestic nuclear power plants were constructed. At that time, welded-in fittings were a more cost-effective construction method. However, pipe bending can now be performed at a lower cost than welding. Further, the development of portable bending machines allows on-site bending of pipe.

Figure I-1 shows isometric views of a section of piping constructed using pipe bending and welded elbows.

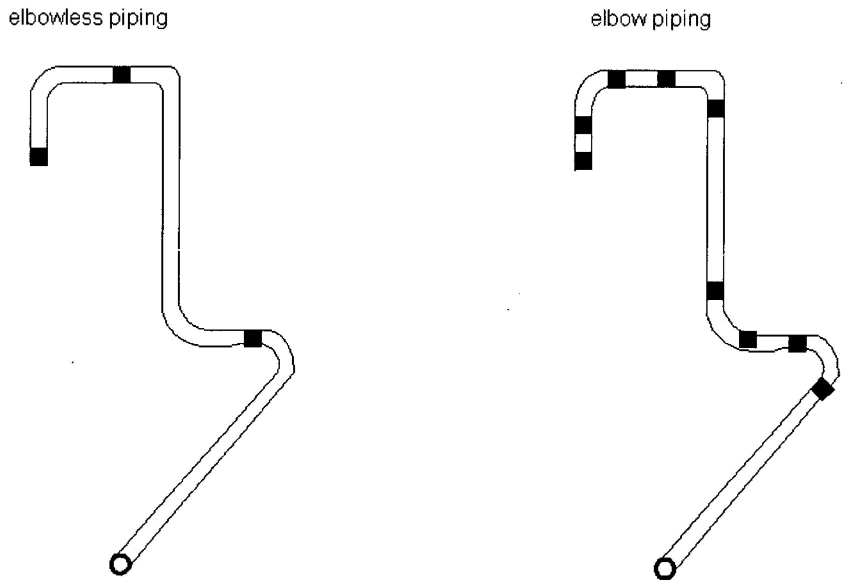

Figure I-1. Comparison of Piping System Construction Pipe Bends vs. Welded Elbows

Several types of pipe bending techniques are currently available. The most common are cold bending, induction bending, and hot slab bending. A brief description of each technique follows.

Cold bending does not apply heat to the pipe segment that is being reshaped. There are several ways to perform a cold pipe bend. The first is to draw bend, or pull, the pipe segment around a circular die to create the desired shape. The second is compression bending, where the pipe is pressed around the die to create the desired shape. The final way is to use a ram to press the pipe into the desired shape (Reference 4). Examples of ram and draw type bending are illustrated in Figure I-2.

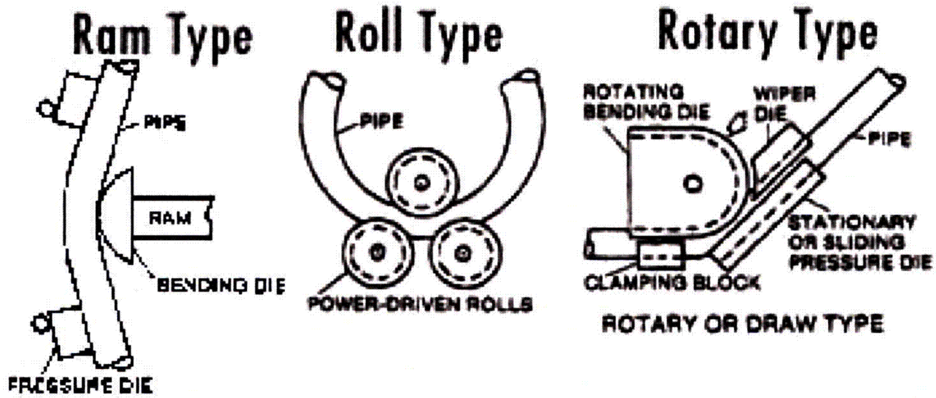

Figure I-2. Types of Cold Bending

Heat induction bending is a technique that uses localized heating in the location of the desired bend. The pipe is pushed through a set of rollers, and then through an induction ring, which is ring shaped to match the contour of the pipe. The induction ring uses electricity to heat the pipe from 800° F to 1200° F. After passing through the induction ring, the pipe is bent and then quenched using water or oil. The radius of the bend is controlled by the radius arm (Reference 4). An example of heat induction bending is shown in Figure I-3.

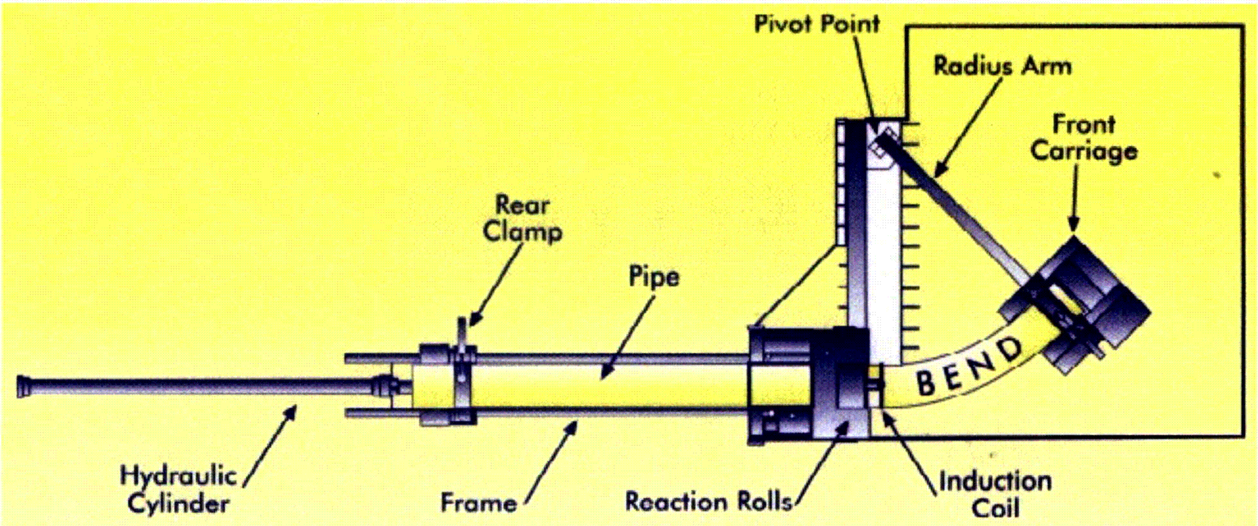

Figure I-3. Schematic of a Heat Induction Bending Machine

The third method of bending pipe is hot slab bending. The pipe is filled with dry sand and placed in a large oven which heats the metal to temperatures near 2000°F. The pipe is taken out of the oven, and secured on a bending table. Cables are attached to the free end of the pipe and pulled by winches to create the desired bend radius and length. This is the oldest pipe bending technique and most common method of bending large bore piping (Reference 4).

1. Implementation Experience

Pipe bending is a proven and commonly used technology. Applications of pipe bending on large construction projects include piping systems at fossil plants, process piping at refineries, replacement pipe in U.S. nuclear power plants, and various piping systems in nuclear power plants in South America and Asia.

Stationary pipe bending machines currently are able to bend pipe sizes in excess of 66 inch outside diameters with wall thicknesses of 5 inches for use in refineries and power plants (Reference 5). Portable bending machines are capable of bending pipe up to 60 inches in diameter (Reference 6). Cold bending is limited to pipes 20 inches in diameter and smaller (Reference 5).

These machines have been commonly used for bending process piping in field fabricated situations.

2. Benefits

There are several advantages to using pipe bends instead of welded elbows in piping systems. The use of pipe bends eliminates a large amount of the field welding required. This will decrease the time required to perform field welding and shorten the construction schedule. The number of welders required on-site will also be reduced. By eliminating welds, the code required inspections for Safety-Related piping are also reduced, reducing the inspection time required during both the construction of the piping system, and throughout the life of the plant. Other construction benefits include the reduction of shoring and scaffolding required onsite. While these construction costs are reduced by increasing the use of pipe bends, there is a small increase in the materials and additional engineering to use pipe bending. Due to wall thinning on the extrados of the bend, larger schedule pipe may be required to ensure that minimum wall thickness requirements are still satisfied.

Bending pipe allows engineers flexibility in locating the weld seams in the piping system. This helps eliminate seams that are difficult to weld, as well as inspect (Reference 3). Typical improvements would be eliminating elbows in close proximity to penetrations, or eliminating several welds in close proximity to one another, such as elbows located close to valves.

Piping in Safety-Related systems require additional inspections throughout the life of the plant. Reducing the number of welds in the plant reduces the number of welds that must be inspected as part of the In-service Inspection (ISI) Plan for the operating nuclear power plant. A typical ASME code inspection of a weld costs approximately $5,000 per weld per inspection. Eliminating welds from the inspection program can save tens of thousands of dollars per outage. Additionally, plants must apply for exemptions when it is not possible to inspect welds, such as those that are difficult to access or those where the local pipe geometry cannot provide accurate inspection results. Eliminating welds that are difficult to inspect reduces the paperwork and other difficulties that plants may face when ISI exemptions are required. Reducing the number of welds that must be inspected will also reduce the radiation exposure to personnel who perform the inspections.

While architect/engineers can use pipe bends to replace welded elbows in many or most applications, not all welded elbows can be replaced by bends. There will be circumstances where a pipe run will require use of a welded elbow rather than a bend in a long run of pipe in order to allow installation or to allow access to other components during construction. A combination of pipe bends and welded elbows is likely to be used in construction.

The disadvantages of selecting pipe bending over using welded fittings are:

- Welded fittings use a standard 1 ½ D radius for elbows. Standard bend radii for bent piping are between 2D and 5D depending on the nominal pipe size and schedule. These bends require more space than welded fittings (Reference 4).

- Bending at elevated temperatures can change the microstructure of the pipe near the bend and result in lower strength and susceptibility to stress corrosion cracking (SCC).

- Cold bending can leave residual stresses in the pipe that make the bend more susceptible to SCC or creep in systems operating in excess of 500°F.

3. Code and Regulatory Issues

The present regulatory codes are based on the ability of the pipe to withstand against internal or external pressure. Since the current codes permit the use of curved pipe, there are no identified unresolved issues.

4. Summary

Potential savings in both construction schedule and cost are available from using pipe bending instead of welded fittings in the construction of piping systems. A review of regulatory codes and standards has indicated that there are no unresolved issues that need to be addressed with future rule-making. This technology is currently being used both domestically and internationally in nuclear power plants.

Since pipe bending is a mature and proven technology, no additional development is needed. Due to the potential benefits of this technology, both during initial construction and throughout the life of the plant, pipe bending should be employed as determined to be optimally cost-effective in the construction of new nuclear power plants. DOE should inform the industry of technology advances in the use of bends rather than welded elbows through publication of this report and possibly through participation in a conference on advanced construction technologies.

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J

Precision Blasting/Rock Removal

Early in the construction phase of a nuclear power plant, excavation work is required to construct the foundations for the Reactor Building, Turbine Building, and other associated support buildings. For domestic nuclear power plants, excavation has traditionally been accomplished through the use of drilling and mechanical methods. In many cases, months were required to excavate the foundations for the Reactor Building alone, adding significant time to the construction schedule and cost.

An alternative to these construction techniques is precision blasting. Precision blasting for excavation involves drilling a series of shafts in an engineered pattern in the area to be removed. The shafts are filled with explosives and a detonation cord is run to a central location at the site. The charges are set off in an order designed to maximize the excavation with minimal amounts of debris and sound damage to the immediate area. Precision blasting is a complicated science, requiring extensive training and knowledge. It requires the use of a specialty contractor to design and control the blasting.

1. Implementation Experience

Since the 1800's, blasting has been used for several applications. Blasting was used to create railroad tunnels and cuts through otherwise impassable land. Blasting is used extensively in mining applications. Since its introduction, precision blasting has become a common means of excavation on large-scale projects such as constructing channels, roadways, and foundations for large structures.

Precision blasting has been successfully performed in the construction of the foundations for domestic nuclear power plant sites. The foundation for the Reactor Building at Millstone Unit 3 was excavated using precision blasting techniques. This is a notable success since the construction was performed while Millstone Unit 1, located only 900 ft away, was operating and Millstone Unit 2, less than 600 feet away, was late in the construction phase. The blasting techniques did not disrupt activities at either unit (Reference 2).

2. Benefits

Some large-scale projects that would require months for excavation have been completed in a few weeks using precision blasting techniques. The exact savings in the schedule are dependent on the type of rock and other geological features of the area, as well as the size and depth of the foundation excavated.

Precision blasting costs are approximately 1/3 the costs of traditional mechanical excavation methods, such as drilling and digging. Part of the cost reduction is due to the ability to remove or loosen a significant portion of the rock for the desired foundation in a short time. Blasting also reduces the personnel and equipment (and associated maintenance costs) required on-site during the excavation process.

Improperly controlled blasting has the potential to initiate problems if performed at a site with a currently operating unit. Seismic activity can result, which may cause the operating unit to shut down. Other concerns include damaging the equipment at the other unit or damaging footings or other concrete work that is being performed nearby. Improperly performed blasting has the capability to change the stability of the local geology, potentially leading to cracking or ground openings.

Regulations are in place to ensure that individuals and companies performing blasting are properly trained and certified. As a result, blasting is routinely performed, and the effects of poorly performed blasting are rare.

3. Code and Regulatory Issues

Regulations have been developed to govern this method of construction due to the risks imposed on the personnel and structures close to the construction site. Both federal and state regulations must be followed prior to and during the blasting process. Specific regulations vary state to state. Once a site is selected for construction, the local regulations will need to be reviewed to determine if blasting is permitted for that location and what, if any, restrictions may apply.

4. Summary

The selection of precision blasting as the method of excavation is impacted by the site geology, structure design, and the type of foundation required. Other factors, such as the federal and state regulations governing blasting, will also influence the acceptability of this construction technique. If precision blasting is applicable as the means of excavation, it can result in a significant savings in cost and schedule. Experience indicates that blasting can be used for construction at sites with existing units without disrupting their operation.

Since precision blasting is a mature and well understood technology, no further research or DOE action is required. DOE should inform the industry of the previous experience in successful use of precision blasting near an operating nuclear power plant through publication of this report and possibly through participation in a conference on advanced construction technologies.

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K

Cable Pulling, Termination and Splices

There have been several advancements in the field of cable pulling, splicing, and termination since construction of existing U.S. nuclear power plants. These advancements can potentially reduce overall plant construction time.

6. ADVANCES IN CABLE INSTALLATION TECHNOLOGY

Cable Pulling

Cable pulling broadly refers to the installation of cables in cable trays or conduits (also referred to as raceways) to connect the electrical loads of the plant to power sources. It is also commonly referred to as cable laying.

A cable or group of cables is pulled through the cable tray or conduit using a pulling rope, which is first routed through in the reverse direction. A lubricant is commonly applied to the cables to reduce friction, thereby allowing a longer cable length to be pulled. A pulling device is used to pull the pulling rope and the cables.

Three advancements in the area of cable pulling involve reducing the coefficient of friction between the cable and raceway or conduit. This allows longer cables to be pulled and allows them to be pulled more quickly, thereby saving time. The advancements that provide a reduced coefficient of friction (COF) are:

- High performance lubricants
- Cable tray rollers
- Cable tray sheaves

Other advancements in cable pulling include:

- Automatic lubricant application. The usual method of applying pulling lubricants is by hand. The lubricant is either poured into an upturned conduit or patted onto the advancing cable jacket throughout the pull. Construction crews who regularly install large amounts of cable are interested in ways to automatically apply pulling lubricant. Automatic application achieves a more uniform application of lubricant and reduces manpower requirements (Reference 7). This method uses a pump and flow regulator operated in concert with the cable pulling equipment.

- Assisted pulling devices. The most common method of pulling cable is with the use of an electric winch or tugger. Pullers are generally rated between 4,000 and 6,500 pounds and provide a direct tension readout as the pull progresses. If an installer is faced with a design calling for a long length of cable to be installed without splices, a second, or assist puller can be used. This assist puller method is accomplished by strategically placing an additional puller and pulling line in a straight section of pull. By pulling the slack cable using the assist puller, the pulling tension and sidewall pressure are reduced. The lead or the main puller will have less load to pull, thereby reducing pulling tensions and sidewall pressures. To safely distribute the pulling stresses on the cable, an assembly called a mare's tail is recommended; otherwise the area of the cable under grip should be wrapped with several layers of friction tape. This approach is discussed in IEEE Std. 576-2000, section 10.4. (See References 6 and 8)

Cable Splicing

Cable splicing is the joining of the two free ends of two cables together. The objective is to make a joint that is electrically equivalent to the cable. Performance characteristics for cable splices are required to conform to IEEE Std. 576-2000 and IEEE Std. 404-2000 (See References 1, 5, 9, 10, 11).

The commonly used methods of splicing are as follows (Reference 1):

- Cold Shrink: A tube or a series of tubes which are expanded to several times their diameter are placed over the conductor and allowed to shrink in diameter over the cable without the use of heat. When cold shrink products are stretched and then allowed to shrink on the cable, they exert a continuous inward pressure on the cable as they try to shrink back to their original diameter, less the permanent set. This inward pressure provides an environmental seal and improves electrical performance

- Heat Shrink: A tube or a series of tubes are applied over the conductor and reduced in diameter over the cable with the use of externally applied heat

- Premolded: The joint is factory molded and is installed by sliding it over the cable. The use of heat is not a part of the installation procedure

Cable Termination

Cable termination describes the treatment of a cable end which is connected to the electrical load or power source. Cable terminations are installed over prepared shielded power cables where a portion of the insulation has been removed. The function of a typical termination is to provide a cable end seal, electrical stress control, and external insulation covering. The cable end seal protects the cable from moisture. The electrical stress control is needed to prevent a dielectric breakdown. External insulation covering must limit leakage current and resist both tracking and erosion from exposure to the environmental conditions in a strong electric field. The commonly used methods of cold shrink, heat shrink, and premolded preparation described above for cable splicing also apply to cable termination.

7. IMPLEMENTATION EXPERIENCE

High performance lubricants and cable tray rollers and sheaves are being routinely used by cable laying crews in the U.S. and other countries. Automated application of lubricants is gaining acceptance and becoming more common primarily due to the reduction in manpower. It could not be determined whether these techniques have been used at recently constructed nuclear power plants.

Assisted cable pulling is also used when necessary for long pulls of cable to save time. It could not be determined whether this technique has been used at recently constructed nuclear power plants. Given that there are few cable pulls of over 1,000 feet in length at nuclear power plants, it is not likely that this technique has been widely used in the construction of new nuclear power plants.

High performance lubricants and assisted cable pulling devices have been used at existing U.S. nuclear power plants during construction, for repairs, and for installing modifications. Examples include: all cable replacement work for restart of Browns Ferry Unit 1, completion of construction at Grand Gulf and Comanche Peak, and replacement of damaged underground cables at Diablo Canyon

Cold shrink technology is mature and has gained industry acceptance for use in splices and end terminations. It could not be determined whether this technique has been used for cable repairs or replacement at U.S. nuclear power plants or for construction of new plants outside the U.S. Heat shrink technology is the standard, and has been used for both repairs and cable replacements at U.S. and foreign nuclear power plants. Preformed fittings are also commonly used for both repairs and cable replacements at U.S. and foreign nuclear power plants. They are simpler to install than heat shrink or cold shrink, but do not allow the flexibility of those techniques and proper fittings may not be available for every situation.

The maturity and improved reliability of splices has led to installation of fully fitted cabling in preassembled modules with over 90% of work completed. Sufficient length of cable is left in a coil at the module boundary so that at the time of installation, each cable is run to a cable splice junction box where numerous cables are spliced for ease of inspection and maintenance in the future. This technique is being used in the U.S. and overseas in construction of ships, fossil power plants, and oil and gas drilling platforms. It is being used in the U.S. in construction of the latest class of nuclear-powered submarines. This concept has not been used in the civilian nuclear industry.

8. BENEFITS

Cable Pulling

<u>High Performance Lubricants</u>
When cables are pulled in cable trays or conduit, an upper limit of the length of cable pulled is calculated to avoid exceeding the maximum cable tension allowed to prevent damage. A key variable in the calculation of maximum allowable tension on the cables during cable pulling is

the frictional coefficient measured between the cable jacket and the conduit wall. One of the more significant factors affecting coefficient of friction (COF) is the presence and the type of lubricant.

Over the past twenty years, the clay slurry lubricants common in power cable installation have been replaced by lower friction, water soluble organic polymer lubricants based on polyethers, polyalcohols, polyamides, and/or neutralized polyacids. Recently, silicone oil polymers (dimethyl polysiloxane) which are not water soluble, have been emulsified in water systems and used in cable pulling lubricants, usually in combination with other polymer systems.

Tests performed by the American Polywater Corporation (a manufacturer of silicone oil polymer lubricants) indicate that high performance polymer lubricants result in COF ranging from 0.10 to 0.20 (References 2 and 3). A silicone oil supplement further lowers this COF. This improvement is on the order of 10%, (i.e., 10% lower tensions on straight pulls, or longer pulls with the same tension). When the pulls include multiple bends, the COF is calculated exponentially, therefore tension is further reduced. The test result data indicates that the COF used in EPRI EL-5036, "Power Plant Electrical Reference Series, Volume 4: Wire and Cable," (Reference 4) may be conservative in calculations when high performance lubricant is used. This conservatism could result in more expense in splicing and conduit access than necessary.

The benefits of using high performance cable pulling lubricants is lower tensions on straight pulls and longer pulling distances for the same tension. Longer pulls reduce the need for splicing and speed the overall cable pulling process. Also, lower dynamic COF of the cable would reduce the cable pulling time.

<u>Cable Tray Rollers and Sheaves</u>

The proper use and location of rollers and sheaves will greatly reduce the necessary tension required to pull cable into the tray. Rollers are used to support the cable in the straight run of the cable tray. When the tray changes direction, sheaves should be employed to satisfy the maximum allowable sidewall pressure limits and minimum bending radii requirements of the cable.

According to IEEE Std. 576-2000, section 10.3.1 (Reference 5), "Field data indicate that an effective coefficient of friction of 0.15 will account for the low rolling friction coefficients of well designed rollers and sheaves in good operating condition."

Use of rollers and sheaves reduces the COF, thereby reducing the cable pulling tension and cable pulling time. This would be noted during the cable pull process as a lower tension indicated on winch instruments, allowing faster pulling, and does not require regulatory or code review.

<u>Automatic Lubricant Application in Cable Pulling</u>

Automatic lubricant application during cable pulling ensures uniformity in application of the lubricant, which reduces the cable COF, and thereby increases cable pulling length and speed and reducing cable installation time. This would be noted during the cable pull process as a lower tension indicated on winch instruments, allowing faster pulling, and does not require regulatory or code review.

Assist Pulling Device

An assist puller allows for pulling longer lengths of cable at one time, which will reduce the time needed to pull longer cables. This would be noted during the cable pull process as a lower tension indicated on winch instruments, allowing faster pulling, and does not require regulatory or code review.

Cable Splices and Terminations

Cold Shrink Technology

Cold shrink technology has become popular in splicing medium-voltage cables over the past 20 years. Cold shrink technology is available for insulation rated from 600V to 35kV. Some of the benefits of the cold shrink technology include:

- No heat, flames, or special installation tools
- Minimal training required
- Easy, fast, and safe installation
- Symmetrical cable cutback dimensions
- Allows transition of different cable sizes within a splice range
- Low temperature handling
- One piece splice body design
- 100% factory tested

The amount of training and skills required for cold shrink is much less compared to the requirements for proper use of other types of splicing and termination technology. It tends to be more reliable than heat shrink, because it provides a constant, even pressure around the conductor and is not dependant on the need to apply heat uniformly, like heat shrink. It does not do a good job of resisting hard objects, though, which is one reason it is not used for direct burial.

A considerable amount of installation time is taken in securing the site safety requirements, applying uniform heat, allowing the splice/terminations to cool down, and transporting the heat torch in making a heat shrink splice/termination. The preparation of conductor in the cable for splice/termination is the same for both cold and heat shrink terminations.

Consolidated statistics from past nuclear power plant construction (Reference 12) indicate that the average man-hour (MH) requirement for a single power termination (pre-molded or heat shrink) is 2.5MH. Use of a cold shrink termination takes no more than 1.0MH for completion and could be done in as little as 0.5MH. This translates into at least a 150% reduction in time for each termination/splice by using cold shrink technology over heat shrink or pre-molded technology. Considering the number of cable terminations in a typical nuclear plant, a considerable reduction in cable installation time can be achieved through use of this technology.

Cable Splices Enable Modules to Be More Finished

One of the emerging technologies in the area of shipbuilding or other modular construction projects is the extensive use of cable splices to enable fully outfitting a module and testing its installed equipment prior to delivery to the project. For example, ships are built in modules and these modules are finally assembled side by side and welded to their neighbors. In the past, long lengths of cable were pulled through many sections of a hull after welding of modules had been completed (Reference 13). Raychem (a manufacturer of cable insulation products) is marketing a family of thick-wall shrink-fit wraps for cable splicing that allow each prefabricated steel module to be fully fitted with all cabling prior to joining to its neighbors. This water-proof splice joint has been approved by Lloyd's Register, American Bureau of Shipping, and Det Norske Veritas (an independent foundation whose services include safety and quality certification of ship designs).

Modules installed in the latest class of submarine have cable pre-installed with coils of lengths needed to reach a cable splice junction box. The cable coils are arranged out of the way of module lifting equipment and hull sections to prevent damage to the cable during transport or installation of the module. This also minimizes safety issues with personnel or equipment entanglement with cable coils on modules to be moved. General Dynamics Electric Boat and Northrop Grumman Newport News developed specifications and tests to prove the splices meet performance requirements. They also developed special tools that apply proper heat and pressure simultaneously for the required amount of time, to speed the splicing process.

This use of cable splicing can be applied to nuclear power plant construction as it makes more use of modularization. For example, piping is being modularized wherever possible, equipment is being pre-installed, cable tray and tray supports come pre-installed inside the modules. This reduces the site work and shortens project completion time. If cables can be preinstalled in modules and connected to cable sections in the neighboring modules using splices, the reduction in construction time could be substantial. Extensive use of splices for nuclear power plants is a new concept and more studies should be done to analyze its benefits and life-cycle costs.

9. CODE AND REGULATORY ISSUES

Cable Pulling Lubricants

The methods set forth in EPRI EL-5036, "Power Plant Electrical Reference Series, Volume 4: Wire and Cable," have been the de facto standard for nuclear power plant cable pulling since it was issued in 1987. While this report addresses the use of some modern lubricants for cable pulling, it has not been updated to include the reduced COF of more advanced lubricants and the longer pulling lengths described in IEEE Std. 576-2000. There should be no regulatory issues with applying the COF estimates based on the use of new lubricants to the calculations in EPRI EL-5036.

Increased Pulling Tension Limits

IEEE Std. 576-2000 (Reference 5) has increased the maximum allowed pulling tension of three-conductor or multi-conductor cables from 6,000 lbs. (in IEEE Std. 576-1989) to 10,000 lbs. (Reference 7). As a result of this change, the maximum allowable pulling tension in EPRI EL-5036 differs from that in IEEE Std. 576-2000 for multicore cables. This increase in allowable tension enables pulling longer cable lengths. There should be no regulatory issues with applying the limit in the latest IEEE standard to the calculations in EPRI EL-5036.

Use of Cold Shrink Splices and Terminations

Raychem heat shrink tubing type WCSF(N) has been used by most domestic nuclear plants for cable splicing. This type is qualified to design basis accident conditions per U.S. Nuclear Regulatory Commission Regulatory Guide 1.131, "Qualification Tests of Electric Cables, Field Splices, and Connections for Light-Water-Cooled Nuclear Power Plants (for Comment)" (Reference 15). The more recently developed cold shrink splices and cable terminations need to be qualified for design basis accident conditions for use in nuclear power plant construction in accordance with applicable regulations.

Use of Splices to Enhance Modularization

The NRC currently recognizes that cable splices are unavoidable, but does not allow their general use. This is stated in regulatory position 3 of U.S. NRC Regulatory Guide 1.75 proposed Revision 3 (December 2003) as follows: "NRC recognizes that cable splices in cable trays cannot be avoided. Field splices should be strictly limited to special circumstances. Cable splices in raceway should generally be avoided to the extent it is practical" (Reference 15). This is a change from the earlier regulatory position. Regulatory position 9 of U.S. NRC Regulatory Guide 1.75, Revision 2 (September 1978), states "Cable splices in raceway should be prohibited" (Reference 14).

10. SUMMARY

Extensive use of the most up-to-date cable pulling methods and systems has the potential to reduce bottlenecks and reduce time and cost for the overall construction schedule of a new nuclear power plant. Given the number and quantity of cables installed in a typical nuclear plant (over 20,000 cables totaling over 6,500,000 lineal feet for a typical single-unit PWR), the potential for time savings is considerable.

Information concerning the use of advanced cable lubricants and other techniques to speed cable pulling such as automatic lubricant pumps and integral cable tray rollers should be disseminated to potential users through publication of this report and participation in a nuclear plant construction method workshop. These technologies do not pose any new code or regulatory issues.

Information concerning the potential for reduction in construction schedule through use of cold-shrink cable splice and termination technology should be disseminated to potential users through publication of this report and participation in a nuclear plant construction method workshop. DOE should encourage EPRI or a manufacturer to perform the necessary environmental qualification testing to qualify cold shrink products for nuclear safety-related system applications.

The use of cable splices as part of modular construction is estimated to shorten new nuclear plant construction schedules by approximately 1 month out of a 66-month construction schedule (see Appendix N for details of this estimate). Therefore, the feasibility and desirability of using this technology should be investigated. MPR recommends that the following actions be taken as part of a nuclear industry-sponsored effort:

1. Perform environmental qualification testing of cold-shrink splices. This could be based on the application of splices found in use in construction of nuclear-powered submarines and the testing used to certify cold-shrink splices for use on commercial ships. The testing should be planned with NRC participation to ensure it addresses potential regulatory concerns.

2. Perform testing, possibly at a national laboratory such as Sandia or Brookhaven where cable insulation aging has been extensively studied, to show that aging of splices does not degrade overall cable performance. The testing should be planned with NRC participation to ensure it addresses potential regulatory concerns.

3. Make results of this work widely available for use in efforts to change industry and NRC standard practice that restricts the use of splices, with the goal of the NRC revising regulatory guidance to incorporate results of performance testing and accepting the use of splices to enhance modular construction. This will support envisioned application of a modularization strategy incorporating splices in new domestic nuclear plant designs and construction plans.

These activities could be co-sponsored by DOE if DOE and industry determine that making this technology available as a construction technique would be a worthwhile effort. The long lead time to adopt splicing technology as industry practice will probably result in its not being available within the next 5 years for the next nuclear plant construction in the U.S.

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L
Advanced Information Management and Control

Nuclear power plant information must be maintained throughout the life of the facility - from requirements definition, project planning, and design to procurement, construction, and operational handover, and throughout facility operation, maintenance and ultimate disposition at the end of its useful life. Information management and control consists of acquisition, storage, retrieval, and manipulation of the plant information. This appendix discusses the current state of the art and future technologies that could be applied for information management and control for future nuclear power plant construction projects.

1. IMPLEMENTATION EXPERIENCE

New Attack Submarine Deployment by General Dynamics Electric Boat

Electric Boat credits part of its success in the development of the Navy's newest submarine class (New Attack Submarine or NSSN) to the use of advanced information management and control technologies (Reference 1 and 2). This project has many parallels to a nuclear power plant construction project. The submarine has a nuclear reactor and related machinery that requires design effort and quality assurance. Also, the boats are built in limited quantities and the engineering and construction effort is a large and complex undertaking.

The first boat in the new submarine class, the USS Virginia, was christened in August 2003. Prior to beginning the design for NSSN, Electric Boat initiated a study to identify the most cost effective and efficient techniques for the new submarine project. Electric Boat concluded that the construction and operating costs for a new submarine were almost entirely determined during development; therefore, improvements in the development process would decrease life cycle costs. The result of the study was the implementation of a program called Integrated Product and Process Development. The intent of this program was to team the designers, builders, life cycle support personnel, quality personnel, and cost personnel within Electric Boat. In addition, the team included the customer (the Navy) and outside equipment suppliers. The goal was to have all stakeholders provide input early in the project, where it would have the greatest impact.

Computerized design databases made the teamwork possible by ensuring that all parties had access to information at all times. Central control of the information ensured that all parties worked to the same baseline. The databases were tools used during initial design and construction. Further, they will provide information throughout the life of every submarine in the class. The use of electronic tools allowed the shift from paper to electronic design information. Two technologies were key in the new submarine project: data modeling and management systems and video telecommunications.
Electric Boat used CATIA, a program developed by Dassault Systems and supported domestically by IBM, for data modeling and management. CATIA provided three-dimensional

CAD capabilities, and data management capabilities. In addition to the existing CATIA capabilities, Electric Boat required extensive customization to achieve process efficiencies for data management. The information in the design models were used to create drawings, parts lists, work orders, and in some cases were used in computer controlled manufacturing.

Video telecommunications allowed continuous involvement of all the relevant parties from an early point in the design. Key decisions could be made rapidly that did not require co-location or extensive travel. Specially built rooms at various sites allowed real time transmittal of 3-D model information, in addition to voice and video. Weekly electronic video teleconferences in these rooms allowed meetings to occur remotely but interactively between various parties. Questions were resolved immediately or in greatly reduced times compared to previous practice. Shipyard workers saw the power of 3-D visualization in meetings with designers and requested that a similar room be installed in the shipyard. Shipyard workers have come to question the need for two dimensional drawings in the future.

CANDU

A recent nuclear power plant construction project in China, known as the Quinshan CANDU project, used several advanced information technologies: the Asset Information System and TRAK databases, the CANDU Material Management System, and the Integrated Electrical and Control Database (Reference 3).

The Asset Information System (AIM) and TRAK databases provided all project participants with access to design and construction documents. It provided the baseline to ensure proper information was used for design and construction, and will be used during operation of the plant.

For the CANDU project, the computer aided design and drafting system (called CADDS) was linked to systems for controlling and managing materials and documentation. In the CANDU Material Management System (CMMS), material management began as soon as design elements were created in CADDS and continued through procurement, storage, and issuing materials at the job site. The CMMS was used to generate requests for quotes for material supply, purchase orders, and to accurately identify materials on-site. Bar codes applied to materials on-site allowed tracking their location with CMMS. CMMS will support operation and maintenance once the plant is on-line.

The Integrated Electrical and Control Database stored all information associated with the design and as-pulled data for wiring, cables, and connectors. The database also integrated with the systems for controlling and managing materials and documentation.

FIATECH

The flow of information is important during all phases of capital projects' life cycles. Figure L-1 illustrates the information flow between the phases of a capital project.

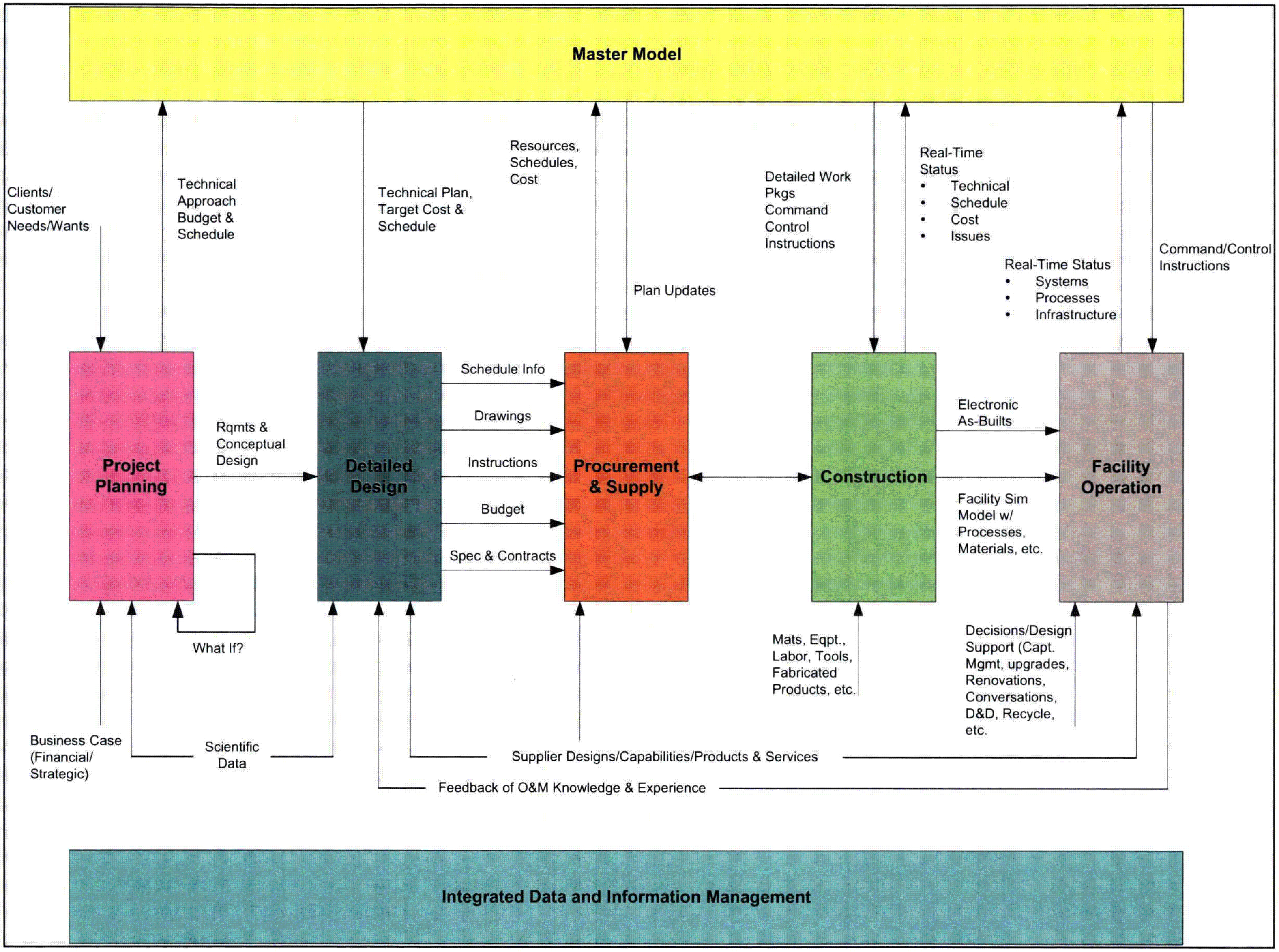

Figure L-1. Schematic of Capital Project Information Flow (largely based on FIATECH, Reference 4)

During project planning, requirements are articulated by the owner/customer. What-if scenarios and the choice of a conceptual design require input from outside sources of information. The financial plan and a high level schedule are created during project planning, but they support decisions made later in the project. The requirements and conceptual design from the planning phase are passed to the detailed design phase.

During detailed design, information provided by vendors and subcontractors for materials, equipment, and subsystems is used to finalize the details of the design. Lessons learned from previous designs (construction, operations, maintenance) guide decisions. The detailed design phase produces drawings, specifications, and instructions for use in procurement and during construction. The detailed design also updates and provides greater detail for the project schedule and budget.

While equipment and materials are procured and supplied, numerous parties must interface with suppliers and shippers. Again, the schedule and budget are updated as this phase progresses.

During construction, on-site personnel require information to efficiently receive materials and equipment. The constructors require work packages from designers. As they progress, the constructors have information to update the schedule and budget. Also, they produce as-built drawings that can be used in operation and maintenance of the plant.

Once plant operations begin, lessons learned can provide valuable feedback for future projects.
In addition, the owner's management of the facility requires a two-way flow of information.

Since all phases of capital projects are interrelated and interdependent, further integration of information flow can improve these projects. There is a need for more effective information management, and standards are needed to support interoperability across the project/facility life cycle.

A partnership named FIATECH aims to build a fully integrated information system for projects and industries. FIATECH, which stands for Fully Integrated and Automated TECHnology, is a partnership of the National Institute of Standards and Technology, industry (including major construction companies, software vendors, oil companies, and utilities), and other government organizations (Reference 4). FIATECH's mission is to direct industry and government appropriations for research and development of new construction technologies. FIATECH is also addressing new materials, new construction methods, and workforce issues that are not addressed in this appendix.

The FIATECH vision for the future of information management and control technologies includes the following:

- Information available on demand to all parties, with appropriate security

- Integration of systems and processes. Project partners and functions can instantly and securely communicate irrespective of geography, culture, and technology preferences

- Interconnected, automated systems and processes that reduce the time and cost of planning, design, and construction

- Collection of tools (software) that are totally interoperable with each other and perform their own function flawlessly while supporting the needs of the other functions. The tools are integrated but flexible to meet the needs of the different stakeholders

- Construction processes that take advantage of the available information technologies to assure conformance with design and regulatory requirements

- Information technology delivering better facilities that are optimized for post-construction operation. The resulting facilities are simplified, and less costly to operate and maintain. Information that was created when the facility was in planning through completion of construction gives the capability to adapt to changing business demands

2. BENEFITS

The benefits are time savings, cost savings, and overall improved project control.

In the future, potential benefits include integrating real-time plant process instrument and control data and 3D computer models for process monitoring and optimization. By combining 3D geometry data and operations data, real-time simulation and analysis of plant processes are possible.

FIATECH

According to FIATECH, the benefits of advanced information flow include:

- Up to 8% reduction in costs for facility creation and renovation

- Up to 14% reduction in project schedules

In addition, FIATECH estimates that improving the interoperability of software used for capital projects would result in savings of $1 billion per year for industry.

CANDU

The CANDU project benefited from the use of advanced information management technology in the following ways:

- The material management system allowed for accurate identification of materials, smoothing the process for materials that required quality assurance and traceability. This is an important improvement for a nuclear power plant

- The electronic data management system ensured that the project team did not have to recreate information for purchase orders

- The electronic data management system will be the basis for inventory, operation, and maintenance once the plant is on-line

Electric Boat NSSN

According to Electric Boat, applying Integrated Product and Process Development (IPPD) to the NSSN has resulted in:

- Drawings issued on schedule and with fewer re-issues as compared to previous submarine classes.

- Drawings for the new submarine were issued on average 2.5 years earlier relative to the start of construction than for previous classes of submarine.

- Construction man-hours are 40% lower for the lead ship (Virginia) as compared to the two previous classes' first ships.

- Virginia was delivered at quality and cost levels that compare to the third ship in class for previous programs.

Electric Boat credits its success to the overall process (IPPD), not just the electronic tools. However, the process was facilitated by the new technology now available for construction projects.

3. Code and Regulatory Issues

Advanced information management and control technologies must be implemented properly to avoid regulatory issues during construction and operation of a new nuclear power plant. Regulations focus on ensuring accuracy, accessibility, and proper documentation of information. No specific limits on the use of electronic systems were identified; however, all requirements of standard information management and control systems would also apply to an electronic system. Proper use of advanced technologies is expected to help plant constructors and operators comply with appropriate codes and regulations. The increased availability of information should facilitate proper oversight scope, scheduling, and verification.

4. Summary

Advanced information management technology is currently in use in the construction industry. The Qinshan CANDU project has integrated some design and parts tracking information and utilizes project databases that provide a baseline for all parties. General

Dynamics Electric Boat has used advanced information technologies in developing the New Attack Submarine. Current information technology has demonstrated success.

Future technologies promise to facilitate communication that was not possible in the past. These technologies, when coupled with the appropriate processes for teamwork, should aid successful development of a new nuclear power plant.

The major hurdle to integrating the project phases is the lack of software compatibility. Currently, software is available for specific functions in support of each project phase. There is no standard for direct flow of information from one program to another. In general, information flow is either a manual process or it does not occur. It is important to note that if generic industry-wide standards are not specified prior to the first utility committing to construction of a new nuclear plant, then problems could arise based on compatibility of the information management systems between the nuclear vendor and the A/E firm.

Another barrier to further information portability is a working environment with multiple companies with disparate goals involved in the design, build, and operations of power plants. Implementation of advanced information management and control technologies will require a major commitment from all parties involved. Support from the users is necessary for the tools to be useful. Companies must be convinced that the significant costs associated with implementing new information technologies will result in schedule and cost reductions of comparable value.

The vendors responsible for new nuclear plant construction will need to perform a study on the processes to be used in a new nuclear plant project. This system should start with project planning and extend through construction to start-up and operation. This study will require input from owners, designers, constructors, operators, and the regulator. The results of the study will guide the development of the appropriate information technologies.

The FIATECH program sponsored by NIST is working to advance the integration of information between the phases of capital projects. Use of advanced information management and control is also explicitly recognized and required in the US Advanced Light Water Reactor (ALWR) Utility Requirements Document. This technology does not require DOE research funding. However, the nuclear industry (e.g., NEI) should obtain information on FIATECH from NIST and conduct an investigation to assess the applicability of this project to improving project coordination for new nuclear plant construction in the U.S.

Also, the investigation could assess the applicability of the FIATECH project to improving communications between the plant construction team and the NRC throughout construction. The investigation should determine steps needed to resolve any NRC concerns about safety-related electronic documentation and safeguarding any sensitive information related to plant security. The NRC is developing its own Construction Inspection Program Information Management System (CIPIMS) to track inspection, test, analysis, and acceptance criteria (ITAAC) during construction of new nuclear power plants. An assessment of the NIST project is recommended because it could improve the process of inspections and approvals by NRC during plant construction, in addition to increasing efficiency during construction. Industry should conduct this assessment and invite NRC to participate.

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Prefabrication, Preassembly, and Modularization

Prefabrication, preassembly, and modularization are construction techniques that are being utilized in many industries, including nuclear power plant construction. These construction techniques will find application, in some form, in any new construction of nuclear power plants.

Prefabrication is a manufacturing process, generally performed at a specialized facility, where materials are joined to form a component part of a final installation. Prefabrication components often involve the work of a single craft, like piping.

Preassembly is a process by which various materials, prefabricated components and/or equipment are joined together at a remote location for subsequent installation as a unit. Preassemblies typically contain portions of systems and require work by multiple crafts.

A module results from a series of remote assembly operations, possibly involving prefabrication and preassembly. Modules are often the largest transportable unit or component of a facility. A module in its most complete form is a volume fitted with all structural elements, finishes, and process components which are designed to occupy that space. Modules can be constructed remotely or constructed at the work site and then placed in position.

There are many motivations for the use of these new construction techniques. A lack of adequate materials or labor at the worksite leads to moving the work to where the labor and materials are located. Difficult site locations can also motivate the creation of new worksites with better conditions (for example, the construction of the international space station or earthbound constructions of an offshore oil rig). The functional characteristics or need for speed and ease of erection of projects may lead to the use of these techniques. Relocation and reuse of a facility may be possible if constructed using modularization. Quality requirements may result in the need for work to occur in a shop rather than the field.

Prefabrication, preassembly, and modularization all allow decoupling sequential activities into parallel activities, providing for possible improvements in the construction schedule. The resulting economics and time savings spur the move to more productive work environments. Technological developments in project planning, design, and materials are enabling the use of these construction techniques.

This section discusses prefabrication, preassembly, and modularization experience and how it can be applied to future nuclear power plants.

1. Implementation Experience

Prefabrication has been used in the building industry for structures such as precast concrete buildings, metal buildings, walls, and space frames. Preassembly has been used in buildings and industrial construction. Skid-mounted pumps and dressed vessels are typical equipment preassemblies. Stairs, catwalks, and instrument panels are small preassemblies, while pipe racks with pipes installed are an example of large assemblies. Modularization has been used by the petrochemical industry to address cold weather challenges in Canada and Alaska. Large modules have also been used for offshore platforms. The following section discusses the use of modularization in shipbuilding, civil works, fossil power plants, and in nuclear power plants.

Northrop Grumman Newport News Shipyard

Newport News shipyard implemented modularization in increasing proportions of the construction of each successive Nimitz class aircraft carrier over the last thirty years. Currently, the shipyard assembles 100-ton modules into 300 to 600-ton "super lifts" (see Figure M-1) that are placed onto ships in drydock (Ref. 1). Newport News is planning to implement modularization even further for the new CVN-21 class. They project that the new ships will include over 60% pre-outfitted building blocks and superlifts.

Newport News is also implementing modularization in the construction of new submarines in conjunction with Electric Boat (discussed more below). Newport News assembles the module structures, and then outfits them with coamings for pipe and cable runs, pipe hangers, and light fixtures. They do not install long electric cables in modules due to a safety concern. Cables are pulled after modules are installed. Newport News uses preassembled pipe as much as possible. They use as-built measurements made by laser to ensure pipe lengths and bends are manufactured correctly to fit (e.g., into bulkhead penetrations).

General Dynamics Electric Boat

Electric Boat is using a modularization concept for constructing the newest class of submarines for the Navy (the first boat is the Virginia) in conjunction with Northrop Grumman Newport News Shipyard. Electric Boat has also used modules in submarine construction for past submarine designs, specifically in hull sections i.e., slices of the boats in the form of cylinders, truncated cones, and end domes as illustrated in Figure M-2. The hull sections are outfitted with internal structures, pipes, and cables installed.

Electric Boat's submarine assembly yard is located in Groton, Connecticut. The hull sections are constructed in an enclosed plant at another facility at Quonset Point, Rhode Island. Hull sections, weighing up to 1400 tons, are transported by barge from Quonset Point to Groton. For the Virginia class, hull sections will also be transported between Electric Boat and Newport News.

The use of modularization has increased the level of completion of the boats at pressure hull closure, from 58% on the Seawolf to 85% complete for the Virginia (Ref. 2). The first hull section of the Virginia was 1100 tons and was 98% outfitted prior to joining to adjacent sections.

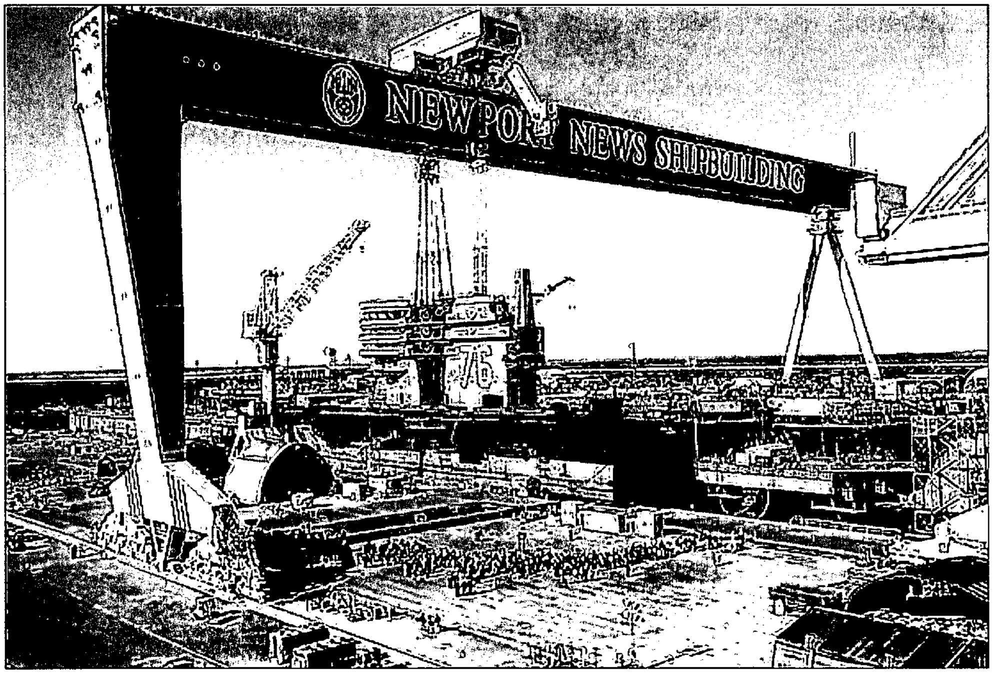

Figure M-1. Lifting the Island for the USS Ronald Reagan, CVN 76
(excerpted from www.nn.northropgrumman.com/photogallery)

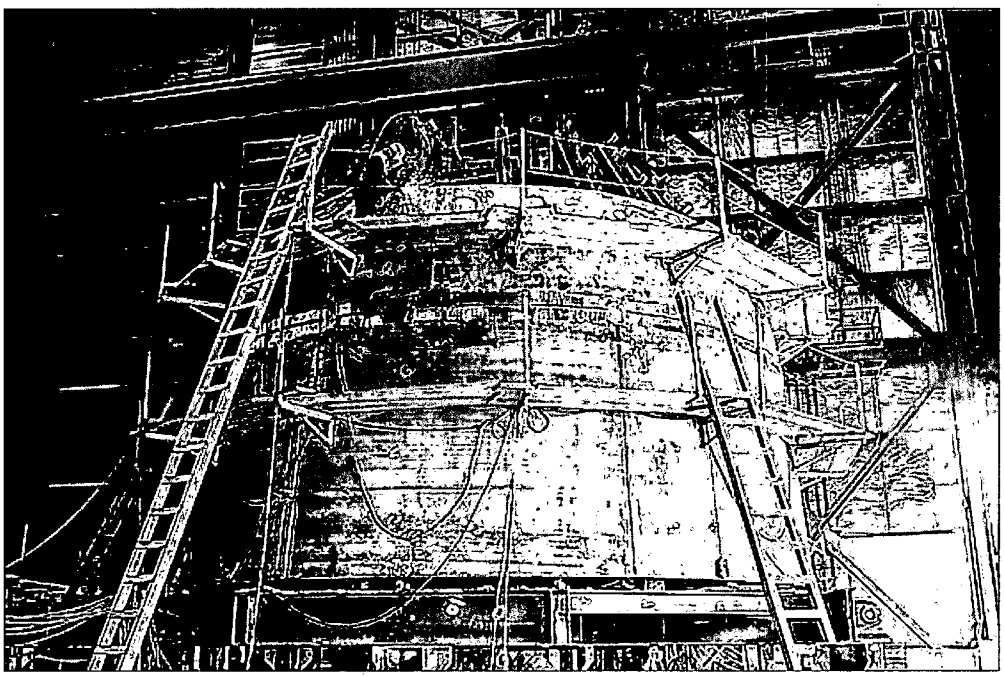

Figure M-2. A Submarine Hull Section
(excerpted from www.nn.northropgrumman.com/photogallery)

Boston's Big Dig

The Ted Williams tunnel in Boston's Big Dig incorporated modularization. Tunnel sections were made of steel tubes that are 40 feet in diameter and 300 feet long. The tubes were built in Baltimore and transported to Boston via barge (see Figure M-3). The tunnels were sunk into trenches that had been dredged in the harbor floor. Twelve tubes were connected to make a ¾-mile tunnel. The tunnels were finished with tiles and lighting after they were sunk into place. Similar construction was used on the Baltimore Harbor Tunnel and elsewhere but with less complete structure.

Figure M-3. Tube Sections for the Ted Williams Tunnel
(excerpted from www.bigdig.com)

Nuclear Power Plants

Modularization has been proposed for use in the construction of the four Generation III+ reactor plants being evaluated by MPR for the DOE NP2010 program.

<u>**AECL ACR-700**</u>

The modularization techniques proposed for the ACR-700 are based on the experience and established work processes of recent CANDU projects. Four CANDU units were built in the 1990's: Qinshan Phase III Units 1 and 2 went into service in 2002 and 2003, and there are two other units currently under construction. Like previous plants, AECL plans to use Hitachi machine shops and satellite offices located in Japan, Canada, and the U.S. for the ACR-700.

The approach for modularization of the ACR-700 involves the use of four module types:

- Multi-discipline modules with process equipment, piping, cable trays, ducting, civil structures, instruments, etc.
- Process equipment and piping modules with equipment, piping, and structural frame
- Piping modules with piping, supports, and structural frame
- Instrumentation, Controls, and/or Electrical (ICE) modules with panels, cabinets, racks, and cable trays

The design packages for the modules of the ACR-700 will be prepared through a process that improves on the methods that were used at Qinshan. The Qinshan design packages were produced by area (location) and by different engineering groups (civil, mechanical, piping, etc.). AECL plans to produce the design packages for the ACR-700 modules in two parallel paths: for construction divided by module with collaborative input from all the engineering groups and for construction divided by volume with input from the engineering groups.

AECL plans four alternative methods for module production:

- Modules completed in a factory and shipped to site
- Sub-modules completed in a factory, shipped separately to the site with final module assembly in an onsite facility
- Components fabricated in a factory, with modules fabricated in an on-site facility
- Major equipment shipped separately to site (a piece of major equipment is considered a module).

The transportation methods available to the construction site will affect the module types used in the plant construction.

AECL states that the construction schedule duration will be reduced since modules will be produced in parallel with site civil work. In addition, the reactor building design is simplified and will require significantly less time to construct in part due to the integration of floors with the modules (floors will be poured in structures integrated with the modules as they are installed). In the proposed ACR design, over 80% of the reactor building is modularized.

GE ESBWR

The structural modules planned for adaptation and use in the GE ESBWR have been used successfully on the ABWR to significantly reduce construction time. The modularization planned for the ESBWR results from the simplification of the systems and structures in the new plant design. Modules will be lowered into position once the floor elevation on which they sit is complete.

GE plans three modularization methods for the ESBWR:

- On-site assembly and modularization of equipment
- Equipment manufacturers providing components that are complete and assembled more than usual
- All equipment provided to a central facility for assembly and installation into modules

The modules may be massive and require special transportation methods.

There are fifteen module types:

- Reactor building (RB) and auxiliary fuel building (FB) precast stair tower/elevator shaft modules
- RB, FB, and control building (CB) structural steel/metal deck modules
- RB, FB, and CB prefabricated rebar mat modules
- RB upper base mat rebar/embedment module
- RB bottom Reinforced Concrete Containment Vessel (RCCV) liner module
- RB RCCV wall rebar modules
- RB RPV pedestal module
- RB RCCV diaphragm floor liner module
- RB upper RCCV wall liner module
- RB drywell equipment and piping support structure (DEPSS)
- RB RCCV top slab liner module
- RB and FB pools liner modules
- RB and FB roof truss structural steel modules
- RB, FB, and CB general area rebar modules
- RB, FB, and CB forms and supports modules

The DEPSS consists of the RPV shield wall, the DEPSS structural steel, and integrated piping duct and electrical components. It is the heaviest and most complex of the modules and, if implemented, provides the most benefit to the construction schedule.

The majority of the module types are civil works. GE acknowledges there may be advantages to development of modules for mechanical and electrical components. It should be noted that GE's ABWR design includes equipment modules in addition to civil modules. GE plans to maximize modularization benefits during the detailed design phase.

In GE's modularization plan the major benefits to shorten the schedule will come in the areas of: reactor building structures, the reactor vessel and connected piping and valves, equipment-like control rod drives in the reactor building, the Reactor Water Cleanup System, and the Shutdown Cooling System. The modularization of the DEPSS will permit the RPV shield wall assembly to be constructed concurrent with other RCCV work, saving significant critical path time. Additional smaller benefits are anticipated in the fuel and control buildings. GE anticipates reduced or no benefit from modularization of activities that are not on the critical path.

Westinghouse AP600

Modules are an integral part of the AP600 design concept. There are approximately 600 modules in the design. All the major pipe areas are modularized. Large modules carry 90% of the pipe, valves, and instruments for containment systems. Of all the pipe welds inside containment, 65% will be made in shops and shipped in modules.

There are five types of modules planned:

- Mechanical Equipment modules- equipment on a common structural frame along with interconnecting piping, valves, instruments, wiring, etc.

- Piping modules- pipe and valves and associated instrumentation on a common structural frame.

- Electrical Equipment modules- electrical equipment on a common structural frame.

- Structural modules- liner modules, wall modules, super floor modules, heat sink floor modules, turbine pedestal form modules, stair modules, platform modules, structural steel modules, space frame modules.

- Wall, basemat, and floor reinforcement modules.

Some of the modules will be shop-assembled, some will be assembled on-site.

Westinghouse states that the total impact of modularization on the construction schedule has not been defined, but that the single largest driver of schedule reduction is modularization.

Many critical path activities are planned to be shortened through modularization. The key components in Westinghouse's construction schedule are:

- On-site fabrication and lifting of completed reinforcement and structural modules into place.
- A modularized containment vessel as opposed to piece-by-piece installation in a congested area.
- Liner modules that can be pre-assembled in parallel with other construction activities.
- Major piping and equipment modules in containment, which are on critical path.
- Any mechanical or electrical modules that must be installed before the floor steel above.

The information presented here is based on the modularization plan for the AP600; however, since the AP1000 is largely the same design, the information is considered applicable.

Toshiba ABWR

Toshiba plans to apply modularization to critical path activities to reduce construction times for the ABWR. Since the critical path is the reactor building, modularization will figure highly there. In addition, modularization is planned for areas that will require large amounts of mechanical and electrical commodities that may become critical path if delayed.

The types of modules planned for the ABWR are based on experience gained in ABWR construction in Japan. The modules are similar to those described in the GE ESBWR section, but additionally the ABWR literature lists the following modules:

- Cable tray modules
- Large bore piping modules
- Large equipment modules (e.g., the condenser)

The RCCV modules are the most important features for maintaining the ABWR schedule. These are modules for: central mat, RCCV lower shell, RCCV diaphragm floor, DEPSS, and top slab. Like the other designs, the ABWR construction schedule relies on modularization for shorter durations.

2. Implications of Prefabrication, Preassembly, and Modularization

The decision to use modularization must be made during the conceptual design stage to maximize its benefits and minimize the detrimental impacts. The ramifications of modularization will impact almost every subsequent decision. Prefabrication and preassembly also require some level of early decisions, although not to the degree required for and resulting from modularization. A summary of the implications of making extensive use of PPM in a construction project is provided in Table M-1.

Table M-1. Significant Changes Required to Implement PPM in Construction Projects

Change	Discussion
Earlier Final Decisions	1. The decision to use PPM must be made during the conceptual design stage to maximize the benefits of its use and minimize the detrimental impacts of the implications of this decision. 2. In order to support design completion, equipment selection, arrangement, pipe and cable layout, etc., must be decided sooner in the engineering process. 3. Equipment and materials will need to be procured earlier than in traditional projects. Project financing must allow for the cash flow required for equipment and module procurement much earlier in the process than for projects without PPM.
Efforts to Optimize Modularization	1. PPM is not beneficial to cost or schedule in every case. Finding the optimum degree of modularization is a tradeoff between such factors as transportation capabilities, lift capabilities, costs, and constructability. The Construction Industry Institute has produced a tool to aid in deciding what level of prefabrication, preassembly, or modularization to use (see Reference 5). 2. Successful use of modularization requires early participation of all disciplines in the module design. The detailed design may require splitting the designers into multidisciplinary module teams. 3. Design and construction teams must be integrated to effectively use modularization. 4. Life-cycle maintenance should also be considered when dividing a facility into modules and arranging equipment and interfaces within modules. This may be of greater concern to the buyer than the builder.
Design Requirements Differ	1. Modular design will require additional structural engineering for each module to be self-supporting as well as supporting the entire structure once assembled. The design of modules will have to consider the rigging requirements, like inclusion of lifting lugs. Center of gravity calculations (for transportation) may impose design constraints that otherwise would not exist. 2. The use of modularization requires choosing how to divide the plant (see Reference 4 for a quantitative method). The detailed design will have to consider laying out the plant in a modular arrangement. 3. Designers will have to consider how to arrange the equipment in the modules to ensure interconnections will function.

Change	Discussion
Increased Reliance on Information Management	1. Computerization in the design process is the key to modularization because of the enormous amount of data generated, processed, and shared between different groups involved in the engineering of modular plants. Information technology and computer-aided design both play a role. 2. Mistakes in procurement must be minimized since they have more significant impacts on cost and schedule for modular projects.
Design, Engineering, and Planning Must Be Completed Earlier	Increased up-front planning is required due to the interdependency of the parts that will make up the new plant. Design and engineering must be completed in time to allow construction planning and final issue of module fabrication specifications. Project financing must allow for more man-hours of engineering and planning effort earlier in the process.
Team Integration and Organization Is More Important	The use of modularization requires a higher level of control and organization during design and procurement than for traditional projects. For the most part, this translates into a need for a high level of information transmittal between organizations and teams. The level of involvement between the project team and the vendor procurement activities will likely be set by the contractual relationship set up between the parties involved.
Transportation Access Affects Design	Modularization requires consideration of transportation issues. The must be adequate site access to deliver large modules. The maximum module size and weight must be considered. The project team will have to survey the transportation routes for oversized module transport.
Standardization Affects Design	If multiple units are to be built using modules, the designers need to tailor the design of overall plant to site and customer requirements, but retain as much in common as possible between plants. One strategy is to divide plants into modules so that site-specific requirements affect the fewest modules, with minimum impact on other modules that can thus be standardized.
Reliance on Module Fabricators	There needs to be a high level of interaction between the project team and module suppliers to ensure all requirements are met. The dependence on suppliers for equipment for the modules and the modules themselves requires a rigorous qualification of bids. The project team will have to try to seek shops with experience in producing modules, or provide appropriate oversight for new processes. Fabricators must ensure dimensional control so that interfaces align between modules.

3. BENEFITS

Prefabrication, preassembly, and modularization increase the number of locations at which work can be performed and shift many of these to a shop environment rather than in the field, reducing construction cost and schedule. Parallel paths for work lead to schedule compression. The total construction duration can be reduced through careful planning. Weather-related challenges and associated downtime can be reduced by moving work from the field into shops. Modularization has the most dramatic effect on the manpower curve for the construction of a nuclear power plant of any of the construction techniques discussed. More effort is shifted into planning, design, and procurement. The manpower required at the construction site is leveled throughout the project.

The project costs from incorporating prefabrication, preassembly, and modularization are affected in different ways, not always resulting in reduction of costs. More engineering is required for these construction techniques, increasing design costs. More materials are required for modularization and the transportation costs are increased. There should be a reduction in construction time since field time is replaced by shop time, which is more efficient. Also, field time should be more efficient in assembling modules than traditional construction techniques. Inspection, calibration, and testing could occur in the module fabrication facility prior to module shipment to work sites. Due to the compact design of modularization, however, maintenance issues at the work site could be harder to resolve. As discussed above, more activities can occur in parallel, shortening construction schedules. Shorter construction schedules typically lead to .lower costs from interest on financing for the project.

Prefabrication, preassembly, and modularization should result in better quality control since more work is performed in the shop than in the field. A related benefit should be that most work is performed in a safer environment than a construction site. Quality control should be tighter since inspections and tests will be easier to perform in the shop than in the field.

4. CODE AND REGULATORY ISSUES

There should be no code impact to the use of modularization, preassembly, or prefabrication since all designs will have to meet existing requirements. The requirements will not change due the use of these construction techniques. Some improvements in the regulatory process may be possible if inspections and tests can be performed while modules are in shops. Conversely, regulatory changes during the project will be even more detrimental since scheduling of the modules will be so integrated and essential to project completion.

5. SUMMARY

Prefabrication, preassembly, and modularization (PPM) have been applied in many and varied construction applications and are certain to be applied in any new nuclear power plant construction in the U.S. The schedule should be compressed using these construction techniques and costs should be reduced, primarily by reducing the costs of financing interest during construction. Careful planning will be required to choose the proper level of application of prefabrication, preassembly, or modularization. Successful implementation will also require consideration of the organization of the project team, the schedule, and transportation issues.

Given the extensive recent use of this technology for fossil power plants and for nuclear powered aircraft carriers and submarines, the issues that will affect use for nuclear plant construction in the U.S. are the application of commercial nuclear power quality standards, ensuring non-U.S. module fabricators can produce the required quality and meet tight schedule demands, and maximizing the cost-effective incorporation of this technology into new plant designs and construction plans. DOE should disseminate information concerning the use of modularization by NSSS vendors through a nuclear plant construction method conference attended by vendor, constructor, and utility representatives. The key prerequisites for successful modularization as described in Table M-1 should be emphasized.

Modularization relies heavily on fabrication capability and transportation infrastructure, and the existing infrastructure may not be adequate for nuclear power plant modular construction in the areas of size, weight, complexity, and quality control.

- Industry should assess module manufacturing capability, define gaps in capability under various construction demand scenarios, determine whether capabilities exist to fabricate the modules needed, define any gaps in capabilities or barriers to their use, and develop approaches to overcome the gaps.

- Industry should assess the impact of 10 CFR 50 Appendix B QA requirements on the availability and feasibility of using PPM. Options for development of new QA methods or programs should be investigated. The findings of this review could be presented to the NRC to discuss measures to resolve the obstacles to increasing the number of domestic and foreign suppliers that meet QA requirements.

6. REFERENCES

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N
Construction Schedule Improvement Analysis

1. PURPOSE

Estimate the reduction in construction schedule for domestic nuclear power plants attributable to advanced construction methods.

2. SCOPE

The potential reduction in construction time is quantified for the technologies recommended for further industry-sponsored research and development. The following technologies were evaluated:

- Cable Laying, Splicing, and Termination
- Modularization

Additionally, the potential schedule savings from the use of steel-plate reinforced concrete structures was evaluated.

The level of accuracy of the estimated reduction in nuclear plant construction schedule is considered sufficient for prioritizing the recommended research and development efforts. The estimates should be used to compare the potential schedule benefit of each construction technology, but as they are based on 1970's-era construction schedules, these estimated time savings are not directly applicable to more recently proposed plant construction schedules.

3. RESULTS

Table N-1 summarizes the estimated improvement in the overall nuclear plant construction schedule provided by each construction method. These estimates are focused on the construction schedule reductions expected between first structural concrete activities ("first concrete") and fuel load. Any benefits derived during the engineering design or other phases of the nuclear plant development are not included in the estimates.

Table N-1. Estimated Construction Schedule Improvements

Construction Method	Appendix	Estimated Schedule Reduction (Months)
Steel-Plate Reinforced Concrete Structures	A	2.3
Cable Splicing	K	1.3
Modularization	M	5

4. UNIVERSAL INPUTS

4.1. Benchmark Project

The benchmark construction project duration used as the basis for estimating the benefit from the advanced construction methodology is 66 months. This value, measured from construction permit issue date to fuel load, is the average construction project duration for 43 domestic nuclear power plants completed by 1979 (Reference 1). Use of this benchmark omits the complicating effects of the regulatory changes following the 1979 accident at Three Mile Island Unit 2. Construction duration was 73 months from groundbreaking to fuel load.

The commodity installation rates for man-hour (MH) requirements to place a unit quantity of cable, pipe, concrete, etc., are given as a high and low value in Reference 1. The low (best) rate is used in this analysis, resulting in conservative estimates of the schedule reduction.

The low (best) rates were selected since the worst-case numbers reported were affected by factors that will be mitigated in any future nuclear plant construction project. Examples of these factors include:

- Labor strikes
- Lost labor man-hours due to waiting for material
- Lost labor man-hours waiting for engineering drawing changes to account for unexpected interferences
- Lost labor man-hours waiting for engineering approval of field routing of pipe
- Lost labor man-hours due to re-work caused by regulatory changes, late design revisions, or failed inspections

4.2. Critical Path Analysis

Construction schedules are reduced by shortening the duration of critical path activities. The maximum schedule reduction for a specific critical path activity occurs when a different activity becomes critical path.

Schedule improvements estimated in this appendix consider only reductions in critical path activities that reduce the overall plant construction time.

It is assumed that construction of the portions of the plant outside containment is not on critical path.

5. CALCULATIONS

5.1. Steel-Plate Reinforced Concrete Structures

Result

The construction schedule for a nuclear power plant is potentially reduced by 71 working days, or a 30% reduction of the postulated 225-day concrete schedule, when steel-plate reinforced concrete (SC) is used during construction. This 2.3 month schedule improvement translates to an approximately 4% reduction in the overall plant construction time of 66 months.

Inputs

Inputs to this calculation are summarized in Table N-2. Additional assumptions regarding the overlap of concrete activities is illustrated in Figure N-1.

Table N-2. Inputs for Steel-Plate Reinforced Concrete Structures

Quantity	Value (see note 1)	Source
MATERIALS		
Amount of materials used to construct concrete walls		Nuclear Industry Experience
Concrete (yd^3)	12,239	
Rebar (ton)	3,107	
Embedments (lbs)	377,147	
Formwork (ft^2)	210,845	
LABOR		
Craft hours for structural concrete in a plant		Nuclear Industry Experience
Concrete (hr)	33,635	
Rebar (hr)	76,890	
Embedments (hr)	89,410	
Formwork (hr)	95,651	
Percentage of concrete craft hours dedicated to removing formwork (%)	40	Assumption
Space requirement of single laborer (ft^2)	300	Assumption
Average work day duration (hr)	10	Assumption
REACTOR BUILDING CHARACTERISTICS		
Shape	Cylinder	Assumption
Diameter (ft)	130	
Height (ft)	100	

Note:

1. The values for the information in this table were obtained from information pertaining to construction of a nuclear safety-related concrete building. That information is proprietary, so only the values are referenced here.

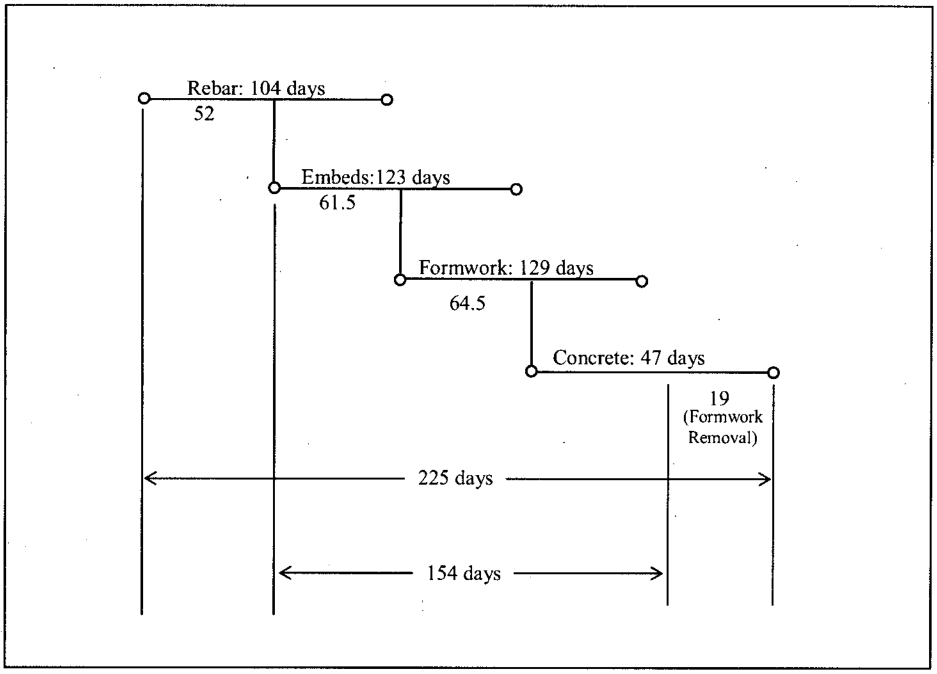

Figure N-1. Construction Schedule Estimate for Reinforced Concrete Inside Reactor Building

Approach

The schedule reduction due to the use of steel-plate reinforced concrete is estimated based on two areas with the potential for substantial time savings:

- Rebar placement
- Formwork removal

Steel-plate reinforced concrete arrives at the construction site in modules. Therefore, no placement of rebar is required. Secondly, these modules are self contained, that is, the steel plates are permanent structures. Therefore, no form work needs to be constructed or removed to support the concrete installation. However, based on the limited industry experience with this technique, there is no construction schedule reduction expected due to replacing formwork assembly with module placement. In addition, time savings associated with scaffolding is not expected since scaffolding will still be required for welding access. Figure N-2 illustrates the differences in the construction activities required.

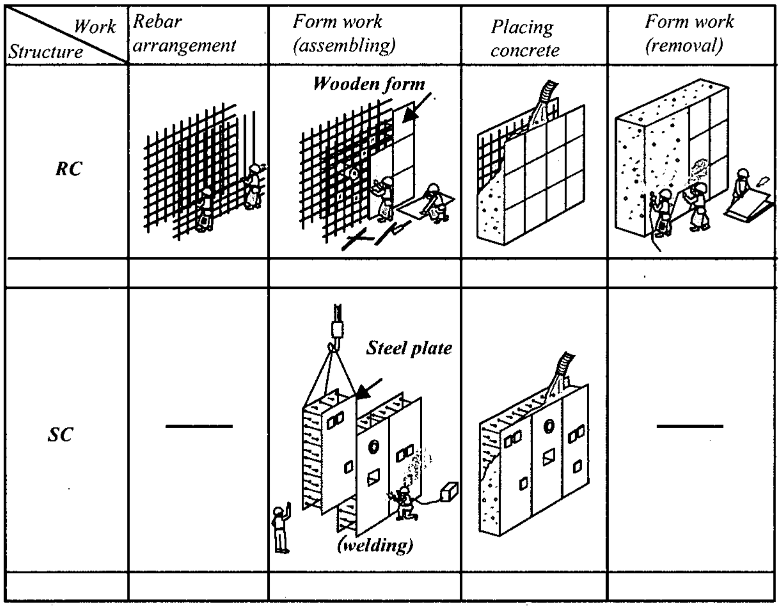

Figure N-2. Comparison of Construction Activities Reinforced Concrete (RC) vs. Steel-Plate Reinforced Concrete (SC) Structures

Calculation

The quantity of materials and labor hours for each material were obtained from past experience in constructing nuclear plant walls. Table N-3 summarizes the quantity of materials used for concrete, formwork, embedments, and rebar. The labor hours needed to place these materials are also listed. These provide the bases for determining the unit effort required to install each material.

Table N-3. Construction of Reinforced Concrete Walls-Material Quantities and Man Hours

Material	Quantity	Units	Construction Labor	
			(MH)	(MH/unit)
Concrete	12,239	yd^3	33,684	2.8
Rebar	3,107	ton	76,890	25
Embeds	377,147	lbs	89,410	0.24
Formwork	210,845	ft^2	95,651	0.45

Using the assumptions in Table N-2 concerning the size of the reactor building and assuming that the amount of concrete needed for the SC structures inside the reactor building is approximately 15 percent of the total containment volume, the concrete volume is calculated as:

$$Concrete\,Volume = (0.15) \cdot \pi \cdot \frac{D^2}{4} \cdot H = (0.15) \cdot \pi \cdot \frac{(130)^2}{4} \cdot (100) = 199{,}098\ \mathrm{ft}^3$$

Converted to cubic yards, the Concrete Volume ≈ 7,500 yd^3.

The quantity of rebar, embedments, and formwork required to construct the walls is calculated from the ratio of these materials to concrete using the values provided in Table N-3. Table N-4 summarizes these ratios.

Table N-4. Ratio of Material Quantities to Quantity of Concrete

Material	Unit	Ratio to Concrete
Concrete	yd^3	1
Rebar	ton	0.25
Embeds	lbs	30.8
Formwork	ft^2	17.2

The ratio of the material to concrete, multiplied by the amount of concrete gives the quantity of material needed for the construction of the walls inside the reactor building. Using these values, the total man-hours needed for construction of each material is calculated. Given the dimensions of the reactor building above, the cross-sectional area of the building is:

$$Area = \frac{1}{4} \cdot \pi \cdot D^2 = \frac{1}{4} \cdot \pi \cdot (130)^2 = 13{,}273 \text{ ft}^2$$

Assuming that an average worker requires 300 square feet of space to work, then work in containment is limited to 45 workers. Therefore, it will be assumed that the crew working on the SC structures consists of about 45 workers. Assuming a work day of 10 hours, the total number of working days to complete the SC structures for each material is also given in Table N-5.

Table N-5. Total Man Hours and Working Days for Each Material

Material	Quantity	Units	MH/unit	Total MH	Working Days
Concrete	7,500	yd^3	2.8	21,000	47
Rebar	1,875	ton	25	46,875	104
Embeds	231,000	lbs	0.24	55,440	123
Formwork	129,150	ft^2	0.45	58,118	129

The overlap in the schedule of construction activities when installing each material is illustrated in Figure N-1. It is assumed that the process of building the walls is scheduled such that each new activity begins approximately halfway through the previous activity. The overall time to construct the walls inside the reactor building is approximately 225 working days.

Because SC structures require no rebar, this will save 52 days off the overall schedule. Since no formwork needs to be removed once the concrete is set, the overall schedule will be shortened further. The amount of time it takes to remove the formwork was included in the concrete material schedule. It is assumed that approximately 40% of the labor hours dedicated to concrete were allotted to stripping the structure of its formwork. Therefore, this is a time saving of approximately 19 working days. Consequently, the overall time savings due to the employment of SC structures in the reactor building is approximately 71 working days, or about 30% of the 225 day concrete construction time. For a 66 month total construction schedule, this 2.3 month schedule improvement translates to an approximately 4% overall schedule savings.

5.2. *Advanced Use of Cable Splicing*

Result

The schedule reduction achievable by advanced use of cable splicing technologies is estimated to be at least 1.3 months.

Inputs

The inputs for calculating the schedule reduction related to cable splicing are provided in Table N-6.

Table N-6. Inputs for Advanced Cable Splicing

Quantity	Value	Source
MATERIALS		
Combined quantity of power and control cable in a single-unit PWR or BWR	6,500,000 LF	Based on industry experience and review of new plant design data.
Combined quantity of power and control cable in reactor building	2,500,000 LF	Based on industry experience and review of new plant design data. (some new plant designs have greatly reduced the quantity of cabling in the reactor building to approximately 15-20% of this value)
Quantity of cable as percentage of total Power Control	 30% 70%	Assumption
Reactor building cable quantity on critical path as percentage of total	50%	Assumption based on 25% critical path overlap with prior and subsequent construction activities
LABOR		
Manpower Requirement Cable laying– Power Cable laying– Control	 High – 0.30 MH/LF Low – 0.10 MH/LF High – 0.09 MH/LF Low – 0.05 MH/LF	Reference 1
Cable laying crew size (No. of laborers)	10	Assumption
Space requirement of single laborer	300 ft^2	Assumption
Work day duration	10 hr	Assumption
REACTOR BUILDING CHARACTERISTICS		
Shape Diameter Height	Cylinder 130 ft 100 ft	Assumption

Approach

Cable splicing adds flexibility to the construction process, which saves time by allowing more activities to be performed in parallel. There are many ways to implement cable splicing in combination with modularization. One possible approach is illustrated in Figure N-3. Here two modules are shown located inside containment, each with one load (E) and one cable terminal box (D). Each load is wired to a motor control center (MCC), located outside containment (A).

Three splicing locations are illustrated. The first, at location B, allows the power cable from the MCC to the common splicing location outside containment to be installed off critical path and independent of the installation of loads. A second location is on the module itself at the module cable terminal box (D). Cables from loads on the module would be routed to this common location. The cable terminal box on the module would be located so as to simplify installation of the module and subsequent power, control, and instrumentation cable connections. This allows the module to be prewired and tested off-site. The third splice location is a cable splice junction box inside containment (C) where several cables from the junction box outside containment (B) will be pulled and spliced to cables from the modules (D). Alternatively, the cables from loads on the modules can be made long enough to reach the cable splice junction box inside containment and modules would be installed with these cable lengths coiled and ready.

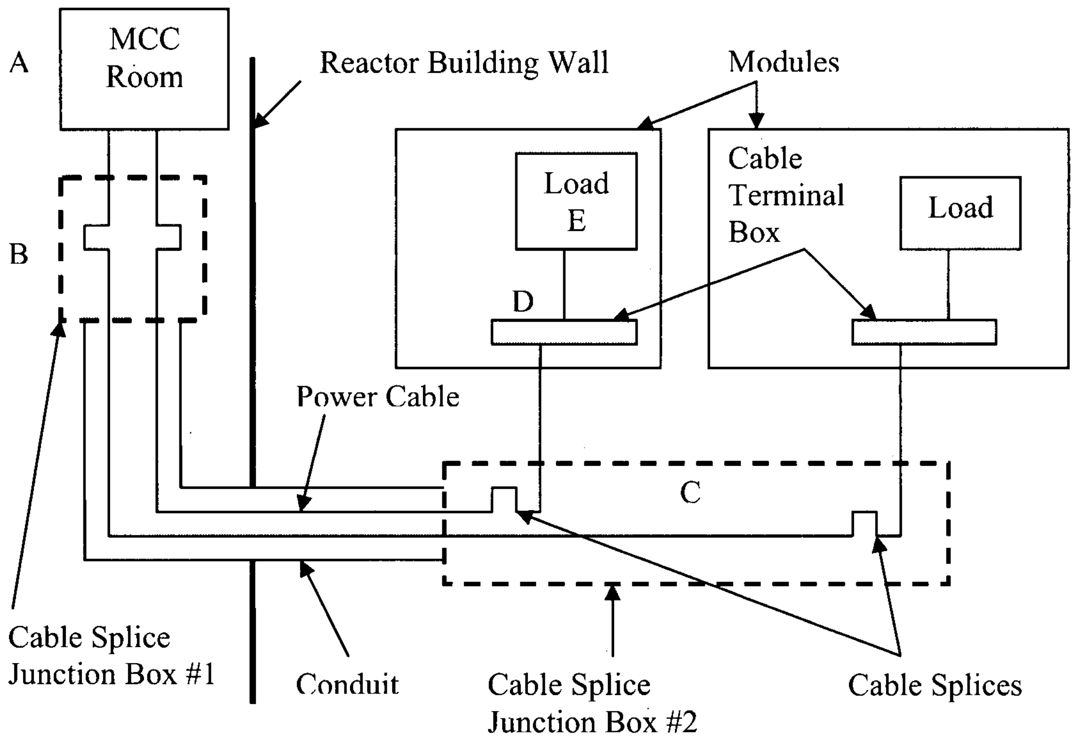

Figure N-3. Conceptual Cable Connections to Modularization

The construction schedule reduction from using splices depends on how much cable is removed from critical path, for example:

- The power cable from the load or module terminal box to cable splice junction box #2 can be pre-wired and coiled inside the module
- The power cable from the MCC room to cable splice junction box #1 is removed from critical path since it can be pulled independent of the reactor building work schedule

Thus, the overall power cable pulling time on critical path is reduced by the percentage of cable due to the use of splicing in combination with modularization. This estimate excludes any schedule reduction achieved as a result of the following:

- Cable pulling using splices are centralized at modules, cable splice junction boxes, and MCCs or switchgear. This would save time in the setup/breakdown of cable pulling equipment and other preparation by craftsmen to perform cable pulling
- Modules have cables and equipment tested in advance of placement in containment to reduce the time needed for post-installation testing
- Separate segments of cables can be installed at different times. This allows rescheduling of installation of segments at times when interferences can be avoided in the work area

Calculation

Power cable and control cable are treated separately because of the difference in man-hours required. The quantity of power and control cable associated with a critical path is calculated based on the following:

- The quantity of cable associated with the schedule critical path in the reactor building (50% of the total), results in 1,250,000 ft of critical path cable
- The breakdown between power and control cable of 30% and 70% of total critical path cable, results in 375,000 ft of power cable and 875,000 ft of control cable on critical path

The schedule reduction due to advanced use of cable splicing technology is calculated as shown in Tables N-7 and N-8.

Table N-7. Power Cable Schedule Reduction Calculation

Estimate	Cable on Critical Path (ft)	Available Labor per Crew (MH/crew-day)	Cable Pulling Rate (ft/day/crew)	Duration of Critical Path (months)	Schedule Improvement (months)
High	375,000	100	333	11	1.3
Low	375,000	100	1000	4.7	0.6

Table N-8. Control Cable Schedule Reduction Calculation

Estimate	Cable on Critical Path (ft)	Available Labor per Crew (MH/crew-day)	Cable Pulling Rate (ft/day/crew)	Duration of Critical Path (months)	Schedule Improvement (months)
High	875,000	100	1111	9.8	1.2
Low	875,000	100	2000	5.5	0.7

The following steps are involved in calculating the schedule reduction:

4. The amount of cable on critical path, calculated above, is listed in Column 2

5. Column 3 lists the maximum labor effort available from a single ten-man cable pulling crew in one ten-hour day

6. Column 4 contains the maximum cable pulling rate for a single crew. An example calculation (for the low estimate for power cables in Table N-6) of this value is:

   (100 MH/crew-day)/(0.10 MH/ft) = 1000 ft/day/crew

7. Column 5 contains the duration of critical path effort required for cable installation. An example calculation (for the low estimate of power cable) of this value is:

   (375,000 ft)/(1000 ft/day * 4 crews) * (1 month/20 working days) = 4.7 months

   The use of four crews is based on the assumption that an average worker requires 300 ft2 of space to work. The total working area in containment is 13,273 ft2 (see steel-plate reinforced concrete structure subsection of this appendix for area calculation). The number of workers in containment is therefore limited to 45. The crew size of 10 limits the number of crews working to 4

8. The length of cable removed from critical path due to pre-installation on the module is estimated to be 2% of the total length. The length of cable removed from critical path due to pre-installation from the MCC to the cable splice junction box outside containment is estimated to be 10% of the total length. Therefore, the reduction in cable length on the critical path is 12%, which also reduces the critical path cable installation effort by 12%

9. The number of months listed in Column 6 is 12% times Column 5

The schedule reductions shown in Tables N-7 and N-8 can be added since the activities would be performed in series, as presented in this analysis. The minimum total schedule improvement associated with advanced use of cable splicing technology is estimated as 1.3 months.

It should be noted that this is a conservative estimate since the improvement can be increased by (1) bundling cables to allow installation of multiple cables in a single pull, (2) pre-installing multiple cables from a MCC to a cable splice junction box, and (3) by taking into account other improvements to the overall project schedule as noted in the Approach discussion.

5.3. Prefabrication, Preassembly, and Modularization

Result

Based on reduction in on-site pipefitting, the construction schedule could potentially be reduced by at least 5 months when modularization is used.

Inputs

The assumptions used in the estimate of the schedule reduction achieved by using modularization are as follows:

- During construction of existing domestic nuclear power plants, the majority of mechanical-related construction man-hours are in three categories:
    - Large bore piping
    - Large bore pipe hangers
    - Small bore piping (which includes pipe hangers)
- Modularization could achieve a reduction of 50% in construction time associated with piping. This overall construction schedule reduction is based on the reduction in the number of field welds, a reduction in the number of hanger installations, and an increase in productivity due to less congested working conditions.

Further inputs to this calculation are provided in Table N-9.

Table N-9. Inputs for Pre-Fabrication, Preassembly, and Modularization

Quantity	Value	Source
LABOR		
Average unit man-hours for pipe fitting for one and two unit nuclear plants of size 800-1150 MWe per unit (man-hours/ft)	High - 13.8 Low - 3.35	Reference 1
Space requirement of single laborer (ft^2)	300	Assumption
Labor reduction due to modularization (%)	50%	Assumption
MATERIALS		
Length of piping (≥ 2.5 in. diam.) required for two-unit nuclear power plant of size range 840-1300 MWe (ft)	170,000 to 275,000	Reference 1
Piping quantity (≥ 2.5 in. diam.) in new plant designs as a percentage of past (%)	Maximum: 90% Minimum: 50%	Assumption
Piping quantity in reactor building relative to total (%)	20-30 %	Assumption
REACTOR BUILDING CHARACTERISTICS		
Shape Diameter (ft) Height (ft)	Cylinder 130 100	Assumption

Approach

This calculation estimates the improvement in the nuclear plant construction schedule based on the pipe installation duration only. It also uses only the low (best-case) value for achieved pipe installation productivity rate (MH/ft) from Reference 1, as previously discussed in Section 4.1 of this Appendix.

Modularization improves the productivity of workers on the job site by reducing the congestion of the work areas. In past nuclear plant construction, congestion slowed work as pipe fitters, electricians, and other trades needed to perform work in the same area (referred to as "stacking trades"). If the modules used include piping and hangers, the majority of pipe welds and hanger installations will be made in a shop. Pipe fitters will only have to make the field welds necessary to connect piping between modules. MPR estimates that the reduction in the number of welds, the reduction in the number of hanger installations, and the increase in productivity due to less congested working conditions could shorten the construction time associated with piping by 50-80%.

Calculation

The calculation of construction schedule reduction due to modularization is shown in Table N-10. The source of the parameters used in Table N-10 that are not calculated is provided in the Inputs subsection.

The schedule improvement calculation in Table N-10 is described as follows:

- The total length of piping used in existing domestic nuclear power plants as determined in the inputs is listed in Column 2
- Column 3 lists the ratio of piping length in the reactor building (critical path piping) relative to the total length for the plant
- Column 4 contains the number of man-hours needed to install 1 ft. of piping
- Column 5 lists the percentage of total piping length in a new nuclear plant (Generation III) relative to total piping length in existing domestic nuclear plant
- Column 6 provides the assumed credit (i.e., percent schedule reduction) due to modularization
- Multiplying the parameters in Columns 2-6 gives the calculated parameter in Column 7

This estimate of the schedule reduction due to the use of modularization is converted to overall schedule reduction by dividing Column 7 by the number of pipefitter man-hours available in one month, provided in Column 8.

The number of pipefitter man-hours available in one month is calculated based on the assumption that an average worker requires 300 ft^2 of space to work. The total working area in containment is 13,273 ft^2 (see steel plate reinforced concrete structure subsection of this appendix for area calculation). Under this assumption, work in containment is limited to 45 workers. Assuming a work day of 10 hours, the maximum personnel effort available for pipe fitting in a month is limited to 9,000 man-hours.

As shown in Table N-10, the schedule improvement due to reduction in pipe installation time is estimated to be between 5 and 61 months. The 61 month reduction used the very low productivity rate of 13.8 MH per foot, and is not a credible value for a 66 month overall schedule. The conservative estimate of 5 months is used in this report. Note, however, that this analysis does not account for the impact of modularization due to higher off-site labor productivity, pre-installation of equipment and instruments, etc.

Table N-10. Calculation of Construction Schedule Improvement due to Modularization

Estimate	Total Length of Piping for Existing Nuclear Plant (ft)	Piping Quantity in Reactor Building Relative to Total (%)	Unit Man-Hours (MH/ft)	Piping Quantity in New Plant Designs Relative to Existing (%)	Credit for Schedule Reduction Due to Modularization (%)	Savings in Pipe Installation Man-Hours thru Use of Modularization, (MH)	Pipefitter Man-Hours per Month (MH/mon)	Time Savings (Months)
Low	170,000	30%	3.35	50%	50%	42,712	9,000	5
High	275,000	20%	13.80	90%	80%	546,480	9,000	61

6. REFERENCES

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Glossary of Acronyms

ABWR	Advanced Boiling Water Reactor
ACR	Advanced CANDU Reactor
ACRS	Advisory Committee on Reactor Safeguards; an independent committee to the that reviews and provides advice on nuclear reactor safety
A/E	Architect/Engineer
AECL	Atomic Energy of Canada Limited
ALWR	Advanced Light Water Reactor
AP1000	Advanced PWR 1000
ARC	Advanced Reactor Corporation; a consortium of operating electric utilities to oversee the development of advanced plant designs
ASL	Approved Supplier List; the list of approved nuclear vendors for safety-related purchases and procurements
BEA	Bid Evaluate and Award
BOP	Balance of Plant; all systems, structures, components, and facilities of the plant not a part of or included in the nuclear island
BWR	Boiling Water Reactor
CED	Contract Effective Date
CIPIMS	Construction Inspection Program Information Management System
COL	Combined Construction and Operating License; a phase in the new reactor licensing process as described in 10CFR Part 52
CP	Construction Permit
CSTA	Calandria and Shield Tanks Assembly

DC	Design Certification; a phase in the new reactor licensing process as described in 10CFR Part 52
DOE	U.S. Department of Energy
EPC	Engineer-Procure-Construct
EPRI	Electric Power Research Institute
ESBWR	Economic Simplified Boiling Water Reactor
ESP	Early Site Permit; a phase in the new reactor licensing process as described in 10CFR Part 52
FC	First Concrete
FL	Fuel Load
FOAK	First-of-a-Kind
FOAKE	First-of-a-Kind Engineering; the effort required to integrate never before used technology from a certified design to a level at which they can be incorporated during the construction stage of a plant. Analysis or testing may be required to prove to the licensing organization that the new design or method conforms to strict requirements that ensure reliability and the ability of the plant to safely operate and shutdown under both normal and abnormal conditions.
FWP	Feedwater Pump
GE	General Electric
HVAC	Heating, Ventilation and Air Conditioning
I&C	Instrumentation and Control
ITAAC	Inspection, Tests, Analysis, and Acceptance Criteria
K-6/K-7	Kashiwazaki-Kariwa Units 6/7
LOCA	Loss of Coolant Accident
LOOP	Loss of Off-site Power
LWA	Limited Work Authorization
LWR	Light Water Reactor

M&E	Mechanical and Electrical
MCC	Motor Control Center
NOAK	Nth-of-a-kind
NP2010	Nuclear Power 2010; a program established by the DOE to deploy new nuclear power plants in the U. S. by 2010
NRC	U.S. Nuclear Regulatory Commission
NPP	Nuclear Power Plant
NSP	Nuclear Steam Plant
NSSS	Nuclear Steam Supply System
NTDG	Near Term Deployment Group; a group established by the DOE to examine prospects for deployment of new nuclear plants in the U. S. in this decade and to identify obstacles to deployment and provide action for resolution
O&M	Operation and Maintenance
OL	Operating License
P&ID	Piping and Instrumentation Diagram
PCS	Passive Containment Cooling System
PHT	Primary Heat Transport
PSAR	Preliminary Safety Analysis Report
PWR	Pressurized Water Reactor
QA	Quality Assurance
RCCV	Reinforced Concrete Containment Vessel
RFC	Release for Construction
RFF	Release for Fabrication
RIP	Reactor Internal Pump
RPV	Reactor Pressure Vessel

SIT	Structural Integrated Test; a test to measure strains in the containment structure
SSLC	Safety System Logic Control
TEPCO	Tokyo Electric Power Company
URD	Utility Requirements Document; a document prepared by the ALWR program team that outlines requirements for future Light Water Reactor designs
VHL	Very Heavy Lift (crane)
W	Westinghouse Electric Company
WBS	Work Breakdown Structure

V10.2-2

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Application of Advanced Construction Technologies to New Nuclear Power Plants

Prepared for

U.S. Department of Energy
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Table N-6. Inputs for Advanced Cable Splicing

Quantity	Value	Source
MATERIALS		
Combined quantity of power and control cable in a single-unit PWR or BWR	6,500,000 LF	Based on industry experience and review of new plant design data.
Combined quantity of power and control cable in reactor building	2,500,000 LF	Based on industry experience and review of new plant design data. (some new plant designs have greatly reduced the quantity of cabling in the reactor building to approximately 15-20% of this value)
Quantity of cable as percentage of total Power Control	 30% 70%	Assumption
Reactor building cable quantity on critical path as percentage of total	50%	Assumption based on 25% critical path overlap with prior and subsequent construction activities
LABOR		
Manpower Requirement Cable laying– Power Cable laying– Control	 High – 0.30 MH/LF Low – 0.10 MH/LF High – 0.09 MH/LF Low – 0.05 MH/LF	Reference 1
Cable laying crew size (No. of laborers)	10	Assumption
Space requirement of single laborer	300 ft^2	Assumption
Work day duration	10 hr	Assumption
REACTOR BUILDING CHARACTERISTICS		
Shape Diameter Height	Cylinder 130 ft 100 ft	Assumption

Further inputs to this calculation are provided in Table N-9,

Table N-9. Inputs for Pre-Fabrication, Preassembly, and Modularization

Quantity	Value	Source
LABOR		
Average unit man-hours for pipe fitting for one and two unit nuclear plants of size 800-1150 MWe per unit (man-hours/ft)	High - 13.8 Low - 3.35	Reference 1
Space requirement of single laborer (ft^2)	300	Assumption
Labor reduction due to modularization (%)	50%	Assumption
MATERIALS		
Length of piping (≥ 2.5 in. diam.) required for two-unit nuclear power plant of size range 840-1300 MWe (ft)	170,000 to 275,000	Reference 1
Piping quantity (≥ 2.5 in. diam.) in new plant designs as a percentage of past (%)	Maximum: 90% Minimum: 50%	Assumption
Piping quantity in reactor building relative to total (%)	20-30 %	Assumption
REACTOR BUILDING CHARACTERISTICS		
Shape Diameter (ft) Height (ft)	Cylinder 130 100	Assumption

Approach

This calculation estimates the improvement in the nuclear plant construction schedule based on the pipe installation duration only. It also uses only the low (best-case) value for achieved pipe installation productivity rate (MH/ft) from Reference 1, as previously discussed in Section 4.1 of this Appendix.

Modularization improves the productivity of workers on the job site by reducing the congestion of the work areas. In past nuclear plant construction, congestion slowed work as pipe fitters, electricians, and other trades needed to perform work in the same area (referred to as "stacking trades"). If the modules used include piping and hangers, the majority of pipe welds and hanger installations will be made in a shop. Pipe fitters will only have to make the field welds necessary to connect piping between modules. MPR estimates that the reduction in the number of welds, the reduction in the number of hanger installations, and the increase in productivity due to less congested working conditions could shorten the construction time associated with piping by 50-80%.

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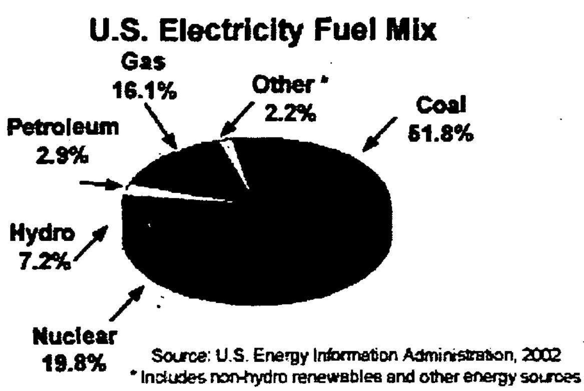
Rec 10.4 Ref 1

CEED Center for Energy and Economic Development

Essential
Affordable
Increasingly Clean

Fuel Diversity

History has taught us that it is risky to develop an over-reliance on any one energy source. In fact, a balanced energy portfolio has been the key to providing America with a growing supply of affordable electricity for the past 30 years.



Fuel diversity helps to protect consumers against the threat of supply disruptions or price volatility. With America's demand for electricity expected to grow 40% by 2020, meeting the nation's growing demand for reliable, affordable electricity will require the continued utilization of all domestic energy resources. And that includes coal, which is the primary source of the electricity that powers America's homes and businesses.

- Currently, more than half of the electricity consumed by U.S. homes and businesses (51.8%) comes from coal.
- Other fuels used to generate electricity include nuclear (19.8%), natural gas (16.1%), hydroelectric facilities (7.2%), petroleum (2.9%), and non-hydro renewables (such as wind and solar) and other energy sources (2.2%).

Fueling America's Future
Growing Demand
Fuel Diversity
Abundant Coal
Affordable Coal
Environmental Progress
Clean Coal Technology
Common-Sense Regulation

Search
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Sec 10.4 Ref 3

DOE/EIA-0383(2004)
January 2004

Annual Energy Outlook 2004

With Projections to 2025

January 2004

For Further Information . . .

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AEO2004 will be available on the EIA web site at www.eia.doe.gov/oiaf/aeo/ in early January 2004. Assumptions underlying the projections and tables of regional and other detailed results will also be available in early January 2004, at web sites www.eia.doe.gov/oiaf/assumption/ and /supplement/. Model documentation reports for the National Energy Modeling System (NEMS) and the report *NEMS: An Overview* are available at web site www.eia.doe.gov/bookshelf/docs.html and will be updated for *AEO2004* in the first few months of 2004.

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Preface

The *Annual Energy Outlook 2004* (*AEO2004*) presents midterm forecasts of energy supply, demand, and prices through 2025 prepared by the Energy Information Administration (EIA). The projections are based on results from EIA's National Energy Modeling System (NEMS).

The report begins with an "Overview" summarizing the *AEO2004* reference case. The next section, "Legislation and Regulations," discusses evolving legislation and regulatory issues. "Issues in Focus" includes discussions of future labor productivity growth; lower 48 natural gas depletion and productive capacity; natural gas supply options, with a focus on liquefied natural gas; natural gas demand for Canadian oil sands production; National Petroleum Council forecasts for natural gas; natural gas consumption in the industrial and electric power sectors; nuclear power plant construction costs; renewable electricity tax credits; and U.S. greenhouse gas intensity. It is followed by a discussion of "Energy Market Trends."

The analysis in *AEO2004* focuses primarily on a reference case and four other cases that assume higher and lower economic growth and higher and lower world oil prices. Forecast tables for those cases are provided in Appendixes A through C. Appendix D provides a summary of key projections in oil equivalent units. Appendix E summarizes projected household expenditures for each fuel by region and household income quintiles. The major results for the alternative cases, which explore the impacts of varying key assumptions in NEMS (such as technology penetration rates), are summarized in Appendix F. Appendix G briefly describes NEMS, the *AEO2004* assumptions, and the alternative cases.

The *AEO2004* projections are based on Federal, State, and local laws and regulations in effect on September 1, 2003. The potential impacts of pending or proposed legislation, regulations, and standards (and sections of existing legislation requiring funds that have not been appropriated) are not reflected in the projections. For example, *AEO2004* does not include the potential impact of the pending Energy Policy Act of 2003. In general, the historical data used for *AEO2004* projections are based on EIA's *Annual Energy Review 2003*, published in October 2003; however, data are taken from multiple sources. In some cases, only partial or preliminary 2002 data were available. Historical data are presented in this report for comparative purposes; documents referenced in the source notes should be consulted for official data values. The projections for 2003 and 2004 incorporate short-term projections from EIA's September 2003 *Short-Term Energy Outlook*.

Federal, State, and local governments, trade associations, and other planners and decisionmakers in the public and private sectors use the *AEO2004* projections. They are published in accordance with Section 205c of the Department of Energy 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.

The projections in *AEO2004* 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 forecasts, given known technology, technological and demographic trends, and current laws and regulations. Thus, they provide a policy-neutral reference case that can be used to analyze policy initiatives. EIA does not propose, advocate, or speculate on future legislative and regulatory changes. All laws are assumed to remain as currently enacted; however, the impacts of emerging regulatory changes, when defined, are reflected.

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, including severe weather, political disruptions, strikes, and technological breakthroughs. In addition, future developments in technologies, demographics, and resources cannot be foreseen with any degree of precision. Many key uncertainties in the *AEO2004* 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, analytical processes in the examination of policy initiatives.

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Overview

Key Energy Issues to 2025

For almost 4 years, natural gas prices have remained at levels substantially higher than those of the 1990s. This has led to a reevaluation of expectations about future trends in natural gas markets, the economics of exploration and production, and the size of the natural gas resource. The *Annual Energy Outlook 2004* (*AEO2004*) forecast reflects such revised expectations, projecting greater dependence on more costly alternative supplies of natural gas, such as imports of liquefied natural gas (LNG), with expansion of existing terminals and development of new facilities, and remote resources from Alaska and from the Mackenzie Delta in Canada, with completion of the Alaska Natural Gas Transportation System and the Mackenzie Delta pipeline.

Crude oil prices rose from under $20 per barrel in the late 1990s to about $35 per barrel in early 2003, driven in part by concerns about the conflict in Iraq, the situation in Venezuela, greater adherence to export quotas by members of the Organization of Petroleum Exporting Countries (OPEC), and changing views regarding the economics of oil production. *AEO2004* reflects changes in expectations about the relative roles of various basins in providing future crude oil supplies.

Outside OPEC, the major sources of growth in crude oil production in the *AEO2004* forecast are Russia, the Caspian Basin, non-OPEC Africa, and South and Central America. U.S. dependence on imported oil has grown over the past decade, with declining domestic oil production and growing demand. This trend is expected to continue. Net imports, which accounted for 54 percent of total U.S. petroleum demand in 2002—up from 37 percent in 1980 and 42 percent in 1990—are expected to account for 70 percent of total U.S. petroleum demand in 2025 in the *AEO2004* forecast, higher than the *Annual Energy Outlook 2003* (*AEO2003*) projection of 68 percent.

The change in expectations for future natural gas prices, in combination with the substantial amount of new natural-gas-fired generating capacity recently completed or in the construction pipeline, has also led to a different view of future capacity additions. Although only a few years ago, natural gas was viewed as the fuel of choice for new generating plants, coal is now projected to play a more important role, particularly in the later years of the forecast. In the *AEO2004* forecast, beyond the completion of plants currently under construction, little new generating capacity is expected to be added before 2010. With a higher long-term forecast for natural gas prices, the competitive position of coal is expected to improve. As a result, cumulative additions of natural-gas-fired generating capacity between 2003 and 2025 are lower in the *AEO2004* forecast than they were in *AEO2003*, and more additions of coal and renewable generating capacity are projected.

Economic Growth

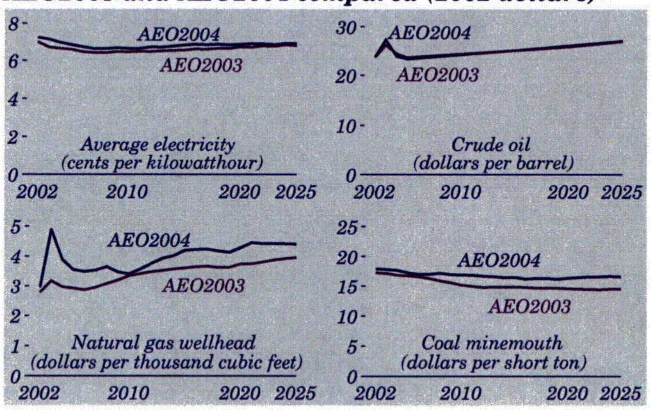
In the *AEO2004* reference case, the U.S. economy, as measured by gross domestic product (GDP), grows at an average annual rate of 3.0 percent from 2002 to 2025, slightly lower than the growth rate of 3.1 percent per year for the same period in *AEO2003*. Most of the determinants of economic growth in *AEO2004* are similar to those in *AEO2003*, but there are some important differences. For example, *AEO2004* starts with lower nominal interest rates than *AEO2003*; the rate of inflation is generally higher; and unemployment levels are higher. Consequently, differences between *AEO2004* and *AEO2003* cannot be explained simply by differences in GDP growth.

Energy Prices

In the *AEO2004* reference case, the average world oil price increases from $23.68 per barrel (2002 dollars) in 2002 to $27.25 per barrel in 2003 and then declines to $23.30 per barrel in 2005. It then rises slowly to $27.00 per barrel in 2025, about the same as the *AEO2003* projection of $26.94 per barrel in 2025 (Figure 1). Between 2002 and 2025, real world oil prices increase at an average rate of 0.6 percent per year in the *AEO2004* forecast. In nominal dollars, the average world oil price is about $29 per barrel in 2010 and about $52 per barrel in 2025.

World oil demand is projected to increase from 78 million barrels per day in 2002 to 118 million barrels per day in 2025, less than the *AEO2003* projection of 123 million barrels per day in 2025. In *AEO2004*,

Figure 1. Energy price projections, 2002-2025: AEO2003 and AEO2004 compared (2002 dollars)



projected demand for petroleum in the United States and Western Europe and, particularly, in China, India, and other developing nations in the Middle East, Africa, and South and Central America is lower than was projected in *AEO2003*. Growth in oil production in both OPEC and non-OPEC nations leads to relatively slow growth in prices through 2025. OPEC oil production is expected to reach 54 million barrels per day in 2025, almost 80 percent higher than the 30 million barrels per day produced in 2002. The forecast assumes that sufficient capital will be available to expand production capacity.

Non-OPEC oil production is expected to increase from 44.7 to 63.9 million barrels per day between 2002 and 2025. Production in the industrialized nations (United States, Canada, Mexico, Western Europe, and Australia) remains roughly constant at 24.2 million barrels per day in 2025, compared with 23.4 million barrels per day in 2002. In the forecast, increased nonconventional oil production, predominantly from oil sands in Canada, more than offsets a decline in conventional production in the industrialized nations.

The largest share of the projected increase in non-OPEC oil production is expected in Russia, the Caspian Basin, Non-OPEC Africa, and South and Central America (in particular, Brazil). Russian oil production is expected to continue to recover from the lows of the 1990s and to reach 10.9 million barrels per day in 2025, 43 percent above 2002 levels. Production from the Caspian Basin is expected to exceed 6.0 million barrels per day by 2025, compared with 1.7 million barrels per day in 2002. In 2025, projected production from South and Central America reaches 7.8 million barrels per day, up from 4.3 million barrels per day in 2002. A large portion of the increase in South and Central American production, 0.9 million barrels per day, is expected to come from nonconventional oil production in Venezuela. Non-OPEC African production is projected to grow from 3.1 million barrels per day in 2002 to 6.7 million barrels per day in 2025.

Average wellhead prices for natural gas (including both spot purchases and contracts) are projected to increase from $2.95 per thousand cubic feet (2002 dollars) in 2002 to $4.90 per thousand cubic feet in 2003, declining to $3.40 per thousand cubic feet in 2010 as the initial availability of new import sources (such as LNG) and increased drilling in response to the higher prices increase supplies. With the exception of a temporary decline in natural gas wellhead prices just before 2020, when an Alaska pipeline is expected to be completed, wellhead prices are projected to increase gradually after 2010, reaching $4.40 per thousand cubic feet in 2025 (equivalent to about $8.50 per thousand cubic feet in nominal dollars). LNG imports, Alaskan production, and lower 48 production from nonconventional sources are not expected to increase sufficiently to offset the impacts of resource depletion and increased demand. At $4.40 per thousand cubic feet, the 2025 wellhead natural gas price in *AEO2004* is 44 cents higher than the *AEO2003* projection. The higher price projection results from reduced expectations for onshore and offshore production of nonassociated gas, based on recent data indicating lower discoveries per well and higher costs for drilling in the lower 48 States.

In *AEO2004*, the average minemouth price of coal is projected to decline from $17.90 (2002 dollars) in 2002 to a low of $16.19 per short ton in 2016. Prices decline in the forecast because of increased mine productivity, a shift to western production, declines in rail transportation costs, and competitive pressures on labor costs. After 2016, however, average minemouth coal prices are projected to rise as productivity improvements slow and the industry faces increasing costs to open new mining areas to meet rising demand. In 2025, the average minemouth price is projected to be $16.57 per short ton, still lower than the real price in 2002 but considerably higher than the *AEO2003* projection of $14.56 per short ton. In nominal dollars, projected minemouth coal prices in *AEO2004* are equivalent to $32 per short ton in 2025.

Average delivered electricity prices are projected to decline from 7.2 cents per kilowatthour in 2002 to a low of 6.6 cents (2002 dollars) in 2007 as a result of cost reductions in an increasingly competitive market—where excess generating capacity has resulted from the recent boom in construction—and continued declines in coal prices. In markets where electricity industry restructuring is still ongoing, it contributes to the projected price decline through reductions in operating and maintenance costs, administrative costs, and other miscellaneous costs. After 2007, average real electricity prices are projected to increase, reaching 6.9 cents per kilowatthour in 2025 (equivalent to 13.2 cents per kilowatthour in nominal dollars). In *AEO2003*, real electricity prices followed a similar pattern but were projected to be slightly lower in 2025, at 6.8 cents per kilowatthour. The higher price projection in *AEO2004* results primarily from higher expected costs for both generation and transmission of electricity. Higher generation costs reflect the higher projections for natural gas and coal prices in *AEO2004*, particularly in the later years of the forecast.

Energy Consumption

Total primary energy consumption in *AEO2004* is projected to increase from 97.7 quadrillion British thermal units (Btu) in 2002 to 136.5 quadrillion Btu in 2025 (an average annual increase of 1.5 percent). *AEO2003* projected total primary energy consumption at 139.1 quadrillion Btu in 2025. The *AEO2004* projections for total petroleum and natural gas consumption in 2025 are lower than those in *AEO2003*, and the projections for coal, nuclear, and renewable energy consumption are higher. Higher natural gas prices in the *AEO2004* forecast, and the effects of higher corporate average fuel economy (CAFE) standards for light trucks in the transportation sector, are among the most important factors accounting for the differences between the two forecasts.

Delivered residential energy consumption, excluding losses attributable to electricity generation, is projected to grow at an average rate of 1.0 percent per year between 2002 and 2025 (1.4 percent per year between 2002 and 2010, slowing to 0.8 percent per year between 2010 and 2025). The most rapid growth is expected in demand for electricity used to power computers, electronic equipment, and appliances. *AEO2004* projects residential energy demand totaling 14.2 quadrillion Btu in 2025 (slightly higher than the 14.1 quadrillion Btu projected in *AEO2003*). The *AEO2004* forecast includes more rapid growth in the total number of U.S. households than was projected in *AEO2003*; however, fewer new single-family homes are projected to be built than in the *AEO2003* forecast, because the mix of single- and multi-family units has been revised, based on preliminary data on housing characteristics from the Energy Information Administration's 2001 Residential Energy Consumption Survey. Multi-family units tend to be smaller and use less energy per household, offsetting some of the increase in projected energy demand due to the increase in the number of U.S. households.

Delivered commercial energy consumption is projected to grow at an average annual rate of 1.7 percent between 2002 and 2025, reaching 12.2 quadrillion Btu in 2025 (slightly less than the 12.3 quadrillion Btu projected in *AEO2003*). The most rapid increase in energy demand is projected for electricity used for computers, office equipment, telecommunications, and miscellaneous small appliances. Commercial floorspace is projected to grow by an average of 1.5 percent per year between 2002 and 2025, identical to the rate of growth in *AEO2003* for the same period.

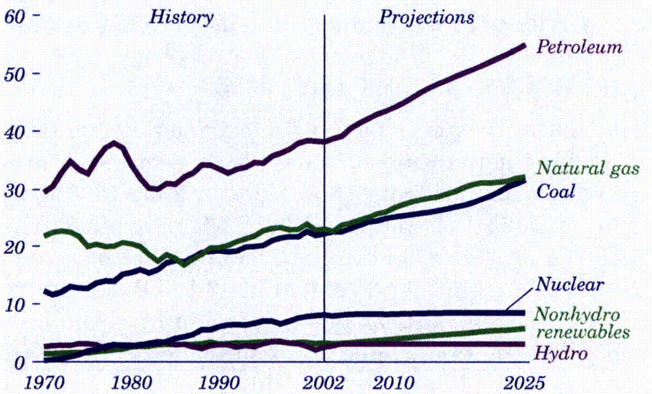
Delivered industrial energy consumption in *AEO-2004* is projected to increase at an average rate of 1.3 percent per year between 2002 and 2025, reaching 33.4 quadrillion Btu in 2025 (lower than the *AEO-2003* forecast of 34.8 quadrillion Btu). The *AEO2004* forecast includes slower projected growth in the dollar value of industrial product shipments and higher energy prices (particularly natural gas) than in *AEO2003*; however, those effects are offset in part by more rapid projected growth in the energy-intensive industries.

Delivered energy consumption in the transportation sector is projected to grow at an average annual rate of 1.9 percent between 2002 and 2025 in the *AEO2004* forecast, reaching 41.2 quadrillion Btu in 2025 (2.5 quadrillion Btu lower than the *AEO2003* projection). Two factors account for the reduction in projected transportation energy use from *AEO2003* to *AEO2004*. First is the adoption of new Federal CAFE standards for light trucks—including sport utility vehicles. The new CAFE standards require that the light trucks sold by a manufacturer have a minimum average fuel economy of 21.0 miles per gallon for model year 2005, 21.6 miles per gallon for model year 2006, and 22.2 miles per gallon for model years 2007 and beyond. (The old standard was 20.7 miles per gallon in all years.) As a result, the average fuel economy for all new light-duty vehicles is projected to increase to 26.9 miles per gallon in 2025 in *AEO2004*, as compared with 26.1 miles per gallon in *AEO2003*. Second is the lower forecast for industrial product shipments in *AEO2004*, leading to a projection for freight truck travel in 2025 that is 7 percent lower than the *AEO2003* projection.

Total electricity consumption, including both purchases from electric power producers and on-site generation, is projected to grow from 3,675 billion kilowatthours in 2002 to 5,485 billion kilowatthours in 2025, increasing at an average rate of 1.8 percent per year (slightly below the 1.9-percent average annual increase projected in *AEO2003*). Rapid growth in electricity use for computers, office equipment, and a variety of electrical appliances in the residential and commercial sectors is partially offset in the *AEO2004* forecast by improved efficiency in these and other, more traditional electrical applications, by the effects of demand-side management programs, and by slower growth in electricity demand for some applications, such as air conditioning, which have reached near-maximum penetration levels in regional markets.

Total demand for natural gas is projected to increase at an average annual rate of 1.4 percent from 2002 to 2025. From 22.8 trillion cubic feet in 2002, natural gas consumption increases to 31.4 trillion cubic feet in 2025 (Figure 2), primarily as a result of increasing use for electricity generation and

Figure 2. Energy consumption by fuel, 1970-2025 (quadrillion Btu)



industrial applications, which together account for almost 70 percent of the projected growth in natural gas demand from 2002 to 2025. The annual rate of increase in natural gas demand varies over the projection period. In particular, the growth in demand for natural gas slows in the later years of the forecast (growing by 0.6 percent per year from 2020 to 2025, as compared with 1.6 percent per year from 2002 to 2020), as rising prices for natural gas make it less competitive for electricity generation. The *AEO2004* projection for total consumption of natural gas in 2025 is 3.5 trillion cubic feet lower than in *AEO2003*.

In *AEO2004*, total coal consumption is projected to increase from 1,066 million short tons (22.2 quadrillion Btu) in 2002 to 1,567 million short tons (31.7 quadrillion Btu) in 2025. From 2002 to 2025, coal use (based on tonnage) is projected to grow by 1.7 percent per year on average, compared with the *AEO2003* projection of 1.4 percent per year. From 2002 to 2025, on a Btu basis, coal use is projected to grow by 1.6 percent per year. (Because of differences in the Btu content of coal across the Nation and changes in the regional mix of coal supply over time, the rate of growth varies, depending on whether it is measured in short tons or Btu.) The primary reason for the change in the rate of growth is higher natural gas prices in the *AEO2004* forecast. In *AEO2004*, total coal consumption for electricity generation is projected to increase by an average of 1.8 percent per year (1.7 percent per year on a Btu basis), from 976 million short tons in 2002 to 1,477 million short tons in 2025, compared with the *AEO2003* projection of 1,350 million short tons in 2025.

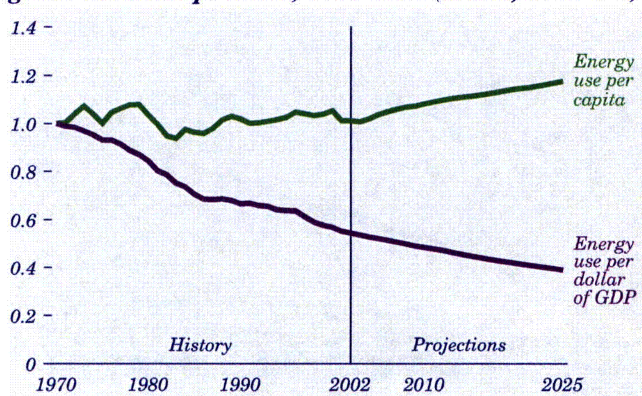
Total petroleum demand is projected to grow at an average annual rate of 1.6 percent in the *AEO2004* forecast, from 19.6 million barrels per day in 2002 to 28.3 million barrels per day in 2025. *AEO2003* projected a 1.8-percent annual average growth rate over the same period. The largest share of the difference between the two forecasts is attributable to the transportation sector. In 2025, total petroleum demand for transportation is 1.2 million barrels per day lower in *AEO2004* than it was in *AEO2003*.

Total renewable fuel consumption, including ethanol for gasoline blending, is projected to grow by 1.9 percent per year on average, from 5.8 quadrillion Btu in 2002 to 9.0 quadrillion Btu in 2025, as a result of State mandates for renewable electricity generation, higher natural gas prices, and the effect of production tax credits. About 60 percent of the projected demand for renewables in 2025 is for grid-related electricity generation (including combined heat and power), and the rest is for dispersed heating and cooling, industrial uses, and fuel blending. Projected demand for renewables in 2025 in *AEO2004* is 0.2 quadrillion Btu higher than in *AEO2003*, with more wind and geothermal energy consumption and less biomass fuel consumption expected in the *AEO2004* forecast.

Energy Intensity

Energy intensity, as measured by energy use per dollar of GDP, is projected to decline at an average annual rate of 1.5 percent in the *AEO2004* forecast, with efficiency gains and structural shifts in the economy offsetting growth in demand for energy services (Figure 3). This rate of improvement, the same as projected in *AEO2003*, is generally consistent with recent historical experience. With energy prices increasing between 1970 and 1986, energy intensity declined at an average annual rate of 2.3 percent, as the economy shifted to less energy-intensive industries, product mix changed, and more efficient technologies were adopted. Between 1986 and 1992, however, when energy prices were generally falling, energy intensity declined at an average rate of only 0.7 percent a year. Since 1992, it has declined on average by 1.9 percent a year.

Figure 3. Energy use per capita and per dollar of gross domestic product, 1970-2025 (index, 1970 = 1)



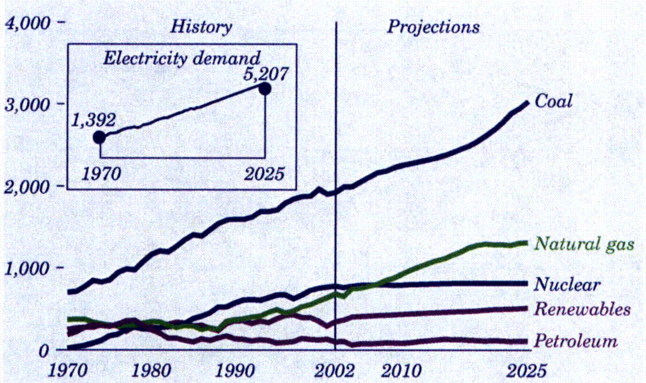
Energy use per person generally declined from 1970 through the mid-1980s but began to increase as energy prices declined in the late 1980s and 1990s. Per capita energy use is projected to increase in the forecast, with growth in demand for energy services only partially offset by efficiency gains. Per capita energy use increases by an average of 0.7 percent per year between 2002 and 2025 in *AEO2004*, the same as in *AEO2003*.

The potential for more energy conservation has received increased attention recently as a potential contributor to the balancing of energy supply and demand as energy supplies become tighter and prices rise. *AEO2004* does not assume policy-induced conservation measures beyond those in existing legislation and regulation or behavioral changes that could result in greater energy conservation.

Electricity Generation

In the *AEO2004* forecast, the projected average price for natural gas delivered to electricity generators is 25 cents per million Btu higher in 2025 than was projected in *AEO2003*. As a result, cumulative additions of natural-gas-fired generating capacity between 2003 and 2025 are lower than projected in *AEO2003*, generation from gas-fired plants in 2025 is lower, and generation from coal, petroleum, nuclear, and renewable fuels is higher. Cumulative natural gas capacity additions between 2003 and 2025 are 219 gigawatts in *AEO2004*, compared with 292 gigawatts in *AEO2003*. The *AEO2004* projection of 1,304 billion kilowatthours of electricity generation from natural gas in 2025 is still nearly double the 2002 level of 682 billion kilowatthours (Figure 4), reflecting utilization of the new capacity added over the past few years and the construction of new natural-gas-fired capacity later in the forecast period to meet increasing demand and replace capacity that is expected to be retired. Less new gas-fired capacity is added in the later years of the forecast because of the projected rise in prices for natural gas and the current surplus of capacity in many regions of the country. In *AEO2003*, 1,678 billion kilowatthours of electricity was projected to be generated from natural gas in 2025.

Figure 4. Electricity generation by fuel, 1970-2025 (billion kilowatthours)



The natural gas share of electricity generation (including generation in the end-use sectors) is projected to increase from 18 percent in 2002 to 22 percent in 2025 (as compared with 29 percent in the *AEO2003* forecast). The share from coal is projected to increase from 50 percent in 2002 to 52 percent in 2025 as rising natural gas prices improve the cost competitiveness of coal-fired technologies. *AEO2004* projects that 112 gigawatts of new coal-fired generating capacity will be constructed between 2003 and 2025 (compared with 74 gigawatts in *AEO2003*).

Nuclear generating capacity in the *AEO2004* forecast is projected to increase from 98.7 gigawatts in 2002 to 102.6 gigawatts in 2025, including uprates of existing plants equivalent to 3.9 gigawatts of new capacity between 2002 and 2025. In *AEO2003*, total nuclear capacity reached a peak of 100.4 gigawatts in 2006 before declining to 99.6 gigawatts in 2025. In a departure from *AEO2003*, no existing U.S. nuclear units are retired in the *AEO2004* reference case. Like *AEO2003*, *AEO2004* assumes that the Browns Ferry nuclear plant will begin operation in 2007 but projects that no new nuclear facilities will be built before 2025, based on the relative economics of competing technologies.

Renewable technologies are projected to grow slowly because of the relatively low costs of fossil-fired generation and because competitive electricity markets favor less capital-intensive technologies in the competition for new capacity. Where enacted, State renewable portfolio standards, which specify a minimum share of generation or sales from renewable sources, are included in the forecast. The production tax credit for wind and biomass is assumed to end on December 31, 2003, its statutory expiration date at the time *AEO2004* was prepared.

Total renewable generation, including combined heat and power generation, is projected to increase from 339 billion kilowatthours in 2002 to 518 billion kilowatthours in 2025, at an average annual growth rate of 1.9 percent. *AEO2003* projected slower growth in renewable generation, averaging 1.4 percent per year from 2002 to 2025.

Energy Production and Imports

Total energy consumption is expected to increase more rapidly than domestic energy supply through 2025. As a result, net imports of energy are projected to meet a growing share of energy demand (Figure 5). Net imports are expected to constitute 36 percent of total U.S. energy consumption in 2025, up from 26 percent in 2002.

Projected U.S. crude oil production increases from 5.6 million barrels per day in 2002 to a peak of 6.1 million barrels per day in 2008 as a result of increased production offshore, predominantly from the deep waters of the Gulf of Mexico. Beginning in 2009, U.S. crude oil production begins a gradual decline, falling to 4.6 million barrels per day in 2025—an average annual decline of 0.9 percent between 2002 and 2025. The *AEO2004* projection for U.S. crude oil production in 2025 is 0.7 million barrels per day lower than was projected in *AEO2003*. The projections for Alaskan production and offshore production in 2025 both are lower than in *AEO2003* (by 660,000 and 120,000 barrels per day, respectively), based on revised expectations about the discovery of new speculative fields in Alaska and on an update of the cost of offshore production.

Total domestic petroleum supply (crude oil, natural gas plant liquids, refinery processing gains, and other refinery inputs) follows the same pattern as crude oil production in the *AEO2004* forecast, increasing from 9.2 million barrels per day in 2002 to a peak of 9.7 million barrels per day in 2008, then declining to 8.6 million barrels per day in 2025 (Figure 6). The projected drop in total domestic petroleum supply would be greater without a projected increase of 590,000 barrels per day in the production of natural gas plant liquids (a rate of increase that is consistent with the projected growth in domestic natural gas production).

In 2025, net petroleum imports, including both crude oil and refined products (on the basis of barrels per day), are expected to account for 70 percent of demand, up from 54 percent in 2002. Despite an expected increase in domestic refinery distillation capacity of 5 million barrels per day, net refined petroleum product imports account for a growing portion of total net imports, increasing from 13 percent in 2002 to 20 percent in 2025 (as compared with 34 percent in *AEO2003*).

The most significant change made in the *AEO2004* energy supply projections is in the outlook for natural gas. Total natural gas supply is projected to increase at an average annual rate of 1.4 percent in *AEO2004*, from 22.6 trillion cubic feet in 2002 to 31.3 trillion cubic feet in 2025, which is 3.3 trillion cubic feet less than the 2025 projection in *AEO2003*. Domestic natural gas production increases from 19.1 trillion cubic feet in 2002 to 24.1 trillion cubic feet in 2025 in the *AEO2004* forecast, an average increase of 1.0 percent per year. *AEO2003* projected 26.8 trillion cubic feet of domestic natural gas production in 2025.

The projection for conventional onshore production of natural gas is lower in *AEO2004* than it was in *AEO2003*, because slower reserve growth, fewer new discoveries, and higher exploration and development costs are expected. In particular, reserves added per well drilled in the Midcontinent and Southwest regions are projected to be about 30 percent lower than projected in *AEO2003*. Offshore natural gas production is also lower in *AEO2004* than in *AEO2003* because of the tendency to find more oil than natural gas in the offshore and at higher costs than previously anticipated. Recent data from the Minerals Management Service show that about three-quarters of the hydrocarbons discovered in deepwater fields are oil, compared with 50 percent assumed in *AEO2003*. Conventional production of associated-dissolved and nonassociated natural gas in the onshore and offshore remains important, meeting 39 percent of total U.S. supply requirements in 2025, down from 56 percent in 2002.

Figure 5. Total energy production and consumption, 1970-2025 (quadrillion Btu)

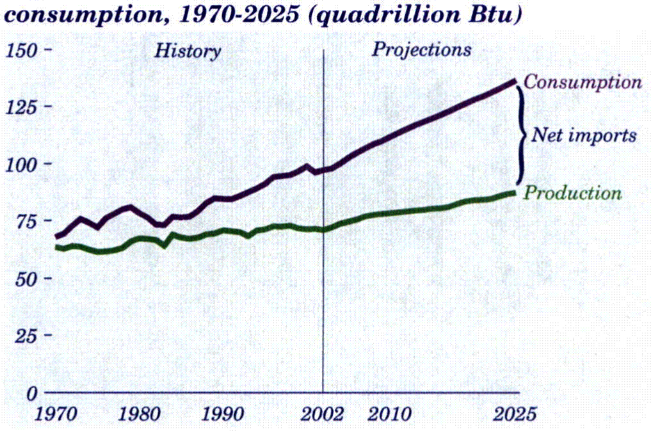
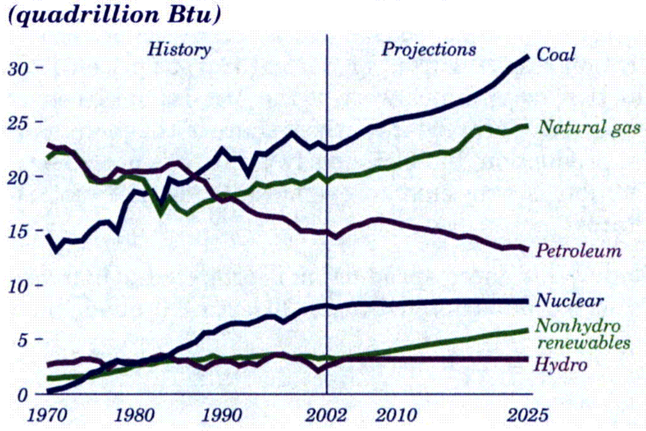


Figure 6. Energy production by fuel, 1970-2025 (quadrillion Btu)



Canadian imports are also projected to be sharply lower in *AEO2004* than in *AEO2003*. Net imports of natural gas from Canada are projected to remain at about the 2002 level of 3.6 trillion cubic feet through 2010 and then decline to 2.6 trillion cubic feet in 2025 (compared with the *AEO2003* projection of 4.8 trillion cubic feet in 2025). The lower forecast in *AEO2004* reflects revised expectations about Canadian natural gas production, particularly coalbed methane and conventional production in Alberta, based on data and projections from the Canadian National Energy Board and other sources.

Growth in U.S. natural gas supplies will be dependent on unconventional domestic production, natural gas from Alaska, and imports of LNG. Total nonassociated unconventional natural gas production is projected to grow from 5.9 trillion cubic feet in 2002 to 9.2 trillion cubic feet in 2025. With completion of an Alaskan natural gas pipeline in 2018, total Alaskan production is projected to increase from 0.4 trillion cubic feet in 2002 to 2.7 trillion cubic feet in 2025. The four existing U.S. LNG terminals (Everett, Massachusetts; Cove Point, Maryland; Elba Island, Georgia; and Lake Charles, Louisiana) all are expected to expand by 2007, and additional facilities are expected to be built in the lower 48 States, serving the Gulf, Mid-Atlantic, and South Atlantic States, with a new small facility in New England and a new facility in the Bahamas serving Florida via a pipeline. Another facility is projected to be built in Baja California, Mexico, serving the California market. Total net LNG imports are projected to increase from 0.2 trillion cubic feet in 2002 to 4.8 trillion cubic feet in 2025, more than double the *AEO2003* projection of 2.1 trillion cubic feet.

As domestic coal demand grows in *AEO2004*, U.S. coal production is projected to increase at an average rate of 1.5 percent per year, from 1,105 million short tons in 2002 to 1,543 million short tons in 2025. Projected production in 2025 is 103 million short tons higher than in *AEO2003* because of a substantial increase in projected coal demand for electricity generation resulting from higher natural gas prices. Production from mines west of the Mississippi River is expected to provide the largest share of the incremental production. In 2025, nearly two-thirds of coal production is projected to originate from the western States.

Renewable energy production is projected to increase from 5.8 quadrillion Btu in 2002 to 9.0 quadrillion Btu in 2025, with growth in industrial biomass, ethanol for gasoline blending, and most sources of renewable electricity generation (including conventional hydroelectric, geothermal, biomass, and wind). The *AEO2004* projection for renewable energy production in 2025 is 0.2 quadrillion Btu higher than was projected in *AEO2003* as a result of higher projections for electricity generation from geothermal and wind energy.

Carbon Dioxide Emissions

Carbon dioxide emissions from energy use are projected to increase from 5,729 million metric tons in 2002 to 8,142 million metric tons in 2025 in *AEO2004*, an average annual increase of 1.5 percent (Figure 7). This is slightly less than the projected rate of increase over the same period in *AEO2003*, 1.6 percent per year.

By sector, projected carbon dioxide emissions from residential, commercial, and electric power sector sources are higher in *AEO2004* than they were in *AEO2003* because of an updated estimate of 2002 emissions and higher projected energy consumption in each of the three sectors—particularly, coal consumption for electricity generation in the electric power sector. Projected carbon dioxide emissions from the industrial and transportation sectors are lower in the *AEO2004* forecast, because of lower projections for industrial natural gas consumption and the new CAFE standards for light trucks as well as other changes in the transportation sector that lead to lower petroleum consumption. The *AEO* projections do not include future policy actions or agreements that might be taken to reduce carbon dioxide emissions.

Figure 7. Projected U.S. carbon dioxide emissions by sector and fuel, 1990-2025 (million metric tons)

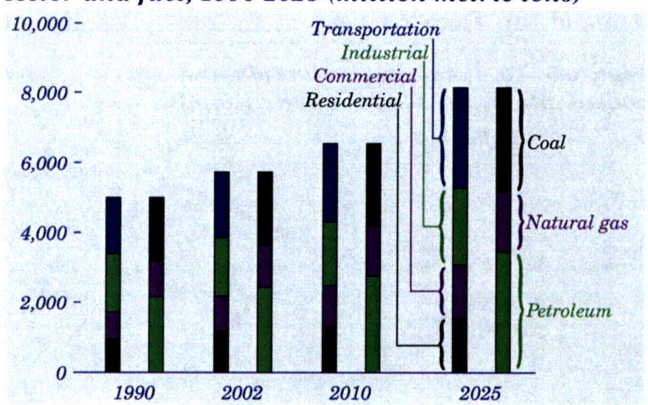


Table 1. Total energy supply and disposition in the *AEO2004* reference case: summary, 2001-2025

Energy and economic factors	2001	2002	2010	2015	2020	2025	Average annual change, 2002-2025
Primary energy production (quadrillion Btu)							
Petroleum	14.70	14.47	15.66	14.91	13.95	13.24	-0.4%
Dry natural gas	20.23	19.56	21.05	22.20	24.43	24.64	1.0%
Coal	23.97	22.70	25.25	26.14	27.92	31.10	1.4%
Nuclear power	8.03	8.15	8.29	8.48	8.53	8.53	0.2%
Renewable energy	5.25	5.84	7.18	7.84	8.45	9.00	1.9%
Other	0.53	1.13	0.88	0.79	0.81	0.84	-1.3%
Total	**72.72**	**71.85**	**78.30**	**80.36**	**84.09**	**87.33**	**0.9%**
Net imports (quadrillion Btu)							
Petroleum	23.29	22.56	28.13	33.20	37.25	41.69	2.7%
Natural gas	3.69	3.58	5.63	6.39	6.63	7.41	3.2%
Coal/other (- indicates export)	-0.67	-0.51	0.06	0.26	0.43	0.61	NA
Total	**26.31**	**25.63**	**33.82**	**39.84**	**44.31**	**49.71**	**2.9%**
Consumption (quadrillion Btu)							
Petroleum products	38.49	38.11	44.15	48.26	51.35	54.99	1.6%
Natural gas	23.05	23.37	26.82	28.74	31.21	32.21	1.4%
Coal	22.04	22.18	25.23	26.32	28.30	31.73	1.6%
Nuclear power	8.03	8.15	8.29	8.48	8.53	8.53	0.2%
Renewable energy	5.25	5.84	7.18	7.84	8.46	9.00	1.9%
Other	0.08	0.07	0.11	0.11	0.07	0.03	-4.6%
Total	**96.94**	**97.72**	**111.77**	**119.75**	**127.92**	**136.48**	**1.5%**
Petroleum (million barrels per day)							
Domestic crude production	5.74	5.62	5.93	5.53	4.95	4.61	-0.9%
Other domestic production	3.11	3.60	3.59	3.72	3.94	3.98	0.4%
Net imports	10.90	10.54	13.17	15.52	17.48	19.67	2.7%
Consumption	19.71	19.61	22.71	24.80	26.41	28.30	1.6%
Natural gas (trillion cubic feet)							
Production	19.79	19.13	20.59	21.72	23.89	24.08	1.0%
Net imports	3.60	3.49	5.50	6.24	6.47	7.24	3.2%
Consumption	22.48	22.78	26.15	28.03	30.44	31.41	1.4%
Coal (million short tons)							
Production	1,138	1,105	1,230	1,285	1,377	1,543	1.5%
Net imports	-29	-23	-2	6	14	23	NA
Consumption	1,060	1,066	1,229	1,291	1,391	1,567	1.7%
Prices (2002 dollars)							
World oil price (dollars per barrel)	22.25	23.68	24.17	25.07	26.02	27.00	0.6%
Domestic natural gas at wellhead (dollars per thousand cubic feet)	4.14	2.95	3.40	4.19	4.28	4.40	1.8%
Domestic coal at minemouth (dollars per short ton)	17.79	17.90	16.88	16.47	16.32	16.57	-0.3%
Average electricity price (cents per kilowatthour)	7.4	7.2	6.6	6.8	6.9	6.9	-0.2%
Economic indicators							
Real gross domestic product (billion 1996 dollars)	9,215	9,440	12,190	14,101	16,188	18,520	3.0%
GDP chain-type price index (index, 1996=1.000)	1.094	1.107	1.301	1.503	1.774	2.121	2.9%
Real disposable personal income (billion 1996 dollars)	6,748	7,032	8,894	10,330	11,864	13,826	3.0%
Value of manufacturing shipments (billion 1996 dollars)	5,368	5,285	6,439	7,345	8,344	9,491	2.6%
Energy intensity (thousand Btu per 1996 dollar of GDP)	**10.53**	**10.36**	**9.17**	**8.50**	**7.91**	**7.37**	**-1.5%**
Carbon dioxide emissions (million metric tons)	**5,691.7**	**5,729.3**	**6,558.8**	**7,028.4**	**7,535.6**	**8,142.0**	**1.5%**

Notes: Quantities are derived from historical volumes and assumed thermal conversion factors. Other production includes liquid hydrogen, methanol, supplemental natural gas, and some inputs to refineries. Net imports of petroleum include crude oil, petroleum products, unfinished oils, alcohols, ethers, and blending components. Other net imports include coal coke and electricity. Some refinery inputs appear as petroleum product consumption. Other consumption includes net electricity imports, liquid hydrogen, and methanol.

Sources: Tables A1, A19, and A20.

Legislation and Regulations

Legislation and Regulations

Introduction

Because analyses by the Energy Information Administration (EIA) are required to be policy-neutral, the projections in this *Annual Energy Outlook 2004* (*AEO2004*) are based on Federal and State laws and regulations in effect on September 1, 2003. The potential impacts of pending or proposed legislation, regulations, and standards—or of sections of legislation that have been enacted but that require funds or implementing regulations that have not been provided or specified—are not reflected in the projections.

Examples of Federal and State legislation incorporated in the projections include the following:

- The Energy Policy Conservation Act of 1975
- The National Appliance Energy Conservation Act of 1987
- The Clean Air Act Amendments of 1990 (CAAA90), which include new standards for motor gasoline and diesel fuel and for heavy-duty vehicle emissions
- The Energy Policy Act of 1992 (EPACT)
- The Omnibus Budget Reconciliation Act of 1993, which added 4.3 cents per gallon to the Federal tax on highway fuels
- The Outer Continental Shelf Deep Water Royalty Relief Act of 1995 and subsequent provisions on royalty relief for new leases issued after November 2000 on a lease-by-lease basis
- The Federal Highway Bill of 1998, which included an extension of the ethanol tax incentive
- The Maritime Security Act of 2002, which amended the Deepwater Port Act of 1974 to include offshore natural gas facilities
- State of Alaska's Right-Of-Way Leasing Act Amendments of 2001, which prohibit leases across State land for a "northern" or "over-the-top" natural gas pipeline route running east from the North Slope to Canada's MacKenzie River Valley
- State renewable portfolio standards, including the California renewable portfolio standards passed on September 12, 2002
- State programs for restructuring of the electricity industry.

AEO2004 assumes that State taxes on gasoline, diesel, jet fuel, and E85 (fuel containing a blend of 70 to 85 percent ethanol and 30 to 15 percent gasoline by volume) will increase with inflation, and that Federal taxes on those fuels will continue at 2002 levels in nominal terms. *AEO2004* also assumes the continuation of the ethanol tax incentive through 2025. Although these tax and tax incentive provisions include "sunset" clauses that limit their duration, they have been extended historically, and *AEO2004* assumes their continuation throughout the forecast.

Examples of Federal and State regulations incorporated in *AEO2004* include the following:

- Standards for energy-consuming equipment that have been announced
- The new corporate average fuel economy (CAFE) standards for light trucks published by the National Highway Traffic Safety Administration (NHTSA) in 2003
- Federal Energy Regulatory Commission (FERC), Orders 888 and 889, which provide open access to interstate transmission lines in electricity markets
- The December 2002 Hackberry Decision, which terminated open access requirements for new onshore liquefied natural gas (LNG) terminals.

AEO2004 includes the CAAA90 requirement of a phased in reduction in vehicle emissions of regulated pollutants. In addition, AEO2004 incorporates the CAAA90 requirement of a phased in reduction in annual emissions of sulfur dioxide by electricity generators, which in general are capped at 8.95 million tons per year in 2010 and thereafter, although "banking" of allowances from earlier years is permitted. *AEO2004* also incorporates nitrogen oxide (NO_x) boiler standards issued by the U.S. Environmental Protection Agency (EPA) under CAAA90. The 19-State NO_x cap and trade program in the Northeast and Midwest is also represented. Limits on emissions of mercury, which have not yet been promulgated, are not represented.

AEO2004 reflects "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements finalized by the EPA in February 2000. The Tier 2 standards for reformulated gasoline (RFG) will be required by 2004 but will not be fully realized in conventional gasoline until 2008 due to allowances for small refineries. *AEO2004* also incorporates the "ultra-low-sulfur diesel" (ULSD) regulation finalized by the EPA in December 2000, which requires the production of at least 80 percent ULSD (15 parts sulfur per million) highway diesel between June 2006 and June 2010 and a 100-percent requirement for ULSD thereafter (see Appendix G for more detail).

Because the new rules for nonroad diesel have not yet been finalized, they are not reflected in the *AEO2004* projections. The *AEO2004* projections reflect legislation that bans or limits the use of the gasoline blending component methyl tertiary butyl ether (MTBE) in the next several years in 17 States and assumes that the Federal oxygen requirement for RFG in Federal nonattainment areas will remain intact.

The provisions of EPACT focus primarily on reducing energy demand. They require minimum building efficiency standards for Federal buildings and other new buildings that receive Federally backed mortgages. Efficiency standards for electric motors, lights, and other equipment are required, and Federal, State, and utility vehicle fleets are required to phase in vehicles that do not rely on petroleum products. The *AEO2004* projections include only those equipment standards for which final actions have been taken and for which specific efficiency levels are provided.

The *AEO2004* reference case projections include impacts of the programs in the Climate Change Action Plan (CCAP)—44 actions developed by the Clinton Administration in 1993 to achieve the stabilization of greenhouse gas emissions (carbon dioxide, methane, nitrous oxide, and others) in the United States at 1990 levels by 2000. Of the 44 CCAP actions, 13 are not related either to energy combustion or to carbon dioxide and, consequently, are not incorporated in the *AEO2004* projections. Although CCAP no longer exists as a unified program, most of the individual programs, which generally are voluntary, remain.

The projections do not include carbon dioxide mitigation actions that may be enacted as a result of the Kyoto Protocol, which was agreed to on December 11, 1997, but has not been ratified or submitted to the U.S. Senate for ratification.

More detailed information on recent legislative and regulatory developments is provided below.

Corporate Average Fuel Economy Standards for Light Trucks

The regulation of fuel economy for new light vehicles was established through the enactment of the Energy Policy Conservation Act of 1975. The regulation of light truck fuel economy was implemented in model year 1979. Increases in light truck CAFE standards continued to be made through the 1980s and 1990s, reaching 20.7 miles per gallon for model year 1996. Thereafter, Congress prohibited any further increases in fuel economy standards.

Congress lifted the prohibition on new CAFE standards on December 18, 2001. On April 1, 2003, NHTSA published a final rule for increasing CAFE standards for light trucks (all pickup trucks, vans, and sport utility vehicles with gross vehicle weight rating less than 8,500 pounds). The new CAFE standard requires that the light trucks sold by a manufacturer have a minimum average fuel economy of 21.0 miles per gallon for model year 2005, 21.6 miles per gallon for model year 2006, and 22.2 miles per gallon for model year 2007. The new light truck CAFE standards are incorporated in *AEO2004*.

California Low Emission Vehicle Program

The Low Emission Vehicle Program (LEVP) was originally passed into legislation in 1990 in the State of California. It began as the implementation of a voluntary opt-in pilot program under the purview of CAAA90, which included a provision that other States could "opt in" to the California program to achieve lower emissions levels than would otherwise be achieved through CAAA90.

The 1990 LEVP was an emissions-based policy, setting sales mandates for three categories of vehicles: low-emission vehicles (LEVs), ultra-low-emission vehicles (ULEVs), and zero-emission vehicles (ZEVs). The mandate required that ZEVs make up 2 percent of new vehicle sales in California by 1998, 5 percent by 2001, and 10 percent by 2003. At that time, the only vehicles certified as ZEVs by the California Air Resources Board (CARB) were battery-powered electric vehicles [*1*].

The LEVP program incorporates the ZEV mandate, which has been revised and delayed several times. In December 2001, the CARB amended the LEVP to include ZEV credits for partial zero-emission vehicles (PZEVs) and advanced technology partial zero-emission vehicles (AT-PZEVs), phase-in credits for pure ZEVs, and additional credits for vehicles with high fuel economy. The ZEV sales mandates were also modified, increasing the ZEV sales requirement from 10 percent in 2003 to 16 percent in 2018. Auto manufacturers in 2002 filed Federal suits in both California and New York, arguing that the CARB revisions to the ZEV program were preempted by the Federal authority over vehicle fuel economy standards. In June 2002, a Federal judge granted a preliminary injunction that prevented the CARB from enforcing the ZEV regulations for model year 2003 and 2004 vehicles.

In April 2003, the CARB proposed further amendments (Resolution 03-4) to the ZEV mandates in response to the suit filed by auto manufacturers, and the manufacturers agreed to settle their litigation with the State of California. The proposed mandate places a greater emphasis on emissions reductions from PZEVs and AT-PZEVs and requires that manufacturers produce a minimum number of fuel cell and electric vehicles. The mandate now requires that ZEVs make up 10 percent of new vehicles sales in 2005, increasing to 16 percent in 2018 and thereafter. The amendment also includes phase-in multipliers for pure ZEVs and allows 20 percent of the sales requirement to be met with AT-PZEVs and 60 percent with PZEVs. AT-ZEVs and PZEVs are allowed 0.2 credit per vehicle. Given the acquiescence of auto manufacturers to the proposed amendments, they are incorporated in the *AEO2004* forecast.

California Carbon Standard For Light-Duty Vehicles

In July 2002, California Assembly Bill 1493 (A.B. 1493) was signed into law. The bill requires the CARB to develop and adopt, by January 1, 2005, a maximum feasible carbon dioxide pollution standard for light-duty vehicles. In estimating the feasibility of the standard, the CARB is required to consider cost-effectiveness, technological capability, economic impacts, and flexibility for manufacturers in meeting the requirement. The standard will apply to light-duty noncommercial passenger vehicles manufactured for model year 2009 and beyond. The bill does not mandate the sale of any specific technology but prohibits the use of the following as options for carbon dioxide reduction: mandatory trip reduction; land use restrictions; additional fees and/or taxes on any motor vehicle, fuel, or vehicles miles traveled; a ban on any vehicle category; a reduction in vehicle weight; or a limitation or reduction of the speed limit on any street or highway in the State. Consequently, A.B. 1493 will rely heavily on vehicle efficiency improvements or a switch to low-carbon fuels to achieve the carbon dioxide emission standard.

If it is determined that low-carbon alternatives are not a feasible solution, A.B. 1493 is likely to face considerable opposition from the auto industry, as evidenced by suits filed in 2002 against California's LEVP. Given that California has not yet set a specific carbon dioxide standard, and given the uncertainty surrounding the possible outcome of future standards, A.B. 1493 is not represented in *AEO2004*.

Regulation of Mercury and Fine Particulate Emissions

The EPA is currently developing regulations to reduce emissions of fine particulates and mercury from electric power plants. Efforts to reduce emissions of particulate matter less than 2.5 microns in diameter ($PM_{2.5}$) began with the issuance of National Ambient Air Quality Standards (NAAQS) on July 16, 1997. Before then, only coarse particle emissions (10 microns and larger) were regulated.

The EPA and the States are now measuring fine particulate concentrations throughout the country to determine which areas are not in compliance with the $PM_{2.5}$, as required by the NAAQS. The EPA plans to make final designations identifying attainment and nonattainment areas by December 15, 2004 [*2*]. Following the EPA designations, States will have 3 years, until December 2007, to prepare State Implementation Plans (SIPs) identifying the steps they will take to bring nonattainment areas into compliance. The SIPs are likely to include plans to reduce emissions from power plants, cars, trucks, and various industrial sources. The States will generally have until 2009, 5 years from their designation, to bring nonattainment areas into compliance, but the deadline could be extended by 5 years under some circumstances. Until the final regulations and SIPs are in place, however, the full impacts on electricity generators will not be known.

On December 14, 2000, the EPA announced that regulating mercury emissions from oil- and coal-fired power plants as a hazardous air pollutant (HAP) under Section (112)(n)(1)(A) of CAAA90 is warranted. The EPA, which has been meeting with various stakeholder groups and reviewing the latest available data on mercury emissions control to develop emissions standards, plans to issue proposed standards on December 15, 2003, and final standards by December 14, 2004 [*3*]. Thereafter, electricity generators will have 3 years, until December 15, 2007, to comply. Although the new regulations are certain to have an impact, particularly on coal-fired plants, because SIPs have not been proposed, their effects are not known and are not reflected in *AEO2004*.

Extension of Deep Shelf Royalty Relief to Existing Leases

The Minerals Management Service (MMS) of the U.S. Department of the Interior [*4*] in March 2003 proposed a new rule that would extend to existing leases the same royalty relief that currently is provided for newly acquired leases, for natural gas production from wells drilled to deep vertical depth (below the "mudline") in the Outer Continental Shelf. Since March 2001, the MMS has provided royalty relief for production from wells drilled to 15,000 feet total vertical depth in newly acquired leases in the shallow waters (less than 200 meters of water depth) of the shelf. Royalty payments to the Federal Government are suspended for the first 20 billion cubic feet of such "deep shelf" production from wells beginning production within the first 5 years of a lease. The purpose of the new rule is to encourage more exploration in the deep shelf play [5], which has significant potential but presents substantial technical difficulties. Of the 10.5 trillion cubic feet of undiscovered resources in the deep shelf (as estimated by the MMS), about 6.3 trillion cubic feet is under existing leases. The proposed new rule would have granted relief for wells drilled after March 26, 2003. Leases currently eligible for royalty relief under the old rule may substitute the deep gas incentive of the new rule.

The proposed rule includes various levels of royalty relief. The first level covers wells drilled to at least 15,000 feet depth, providing relief on a minimum of 15 billion cubic feet of gas. A second level covers wells more than 18,000 feet deep, which would receive royalty relief on a minimum of 25 billion cubic feet. In addition, until a successful well is drilled, unsuccessful wells drilled to a depth of at least 15,000 feet would receive a royalty "credit" for 5 billion cubic feet of gas. Credits could be received for up to two wells. Thus, if two dry holes were drilled, the operator would accrue credits for 10 billion cubic feet, which could be added to the royalty relief for 15 billion cubic feet from a future, successful well drilled on the same lease. As of December 1, 2003, this proposal was still under review at the MMS. It is not included in *AEO2004*.

The Maritime Security Act of 2002 Amendments to the Deepwater Port Act

The Maritime Security Act of 2002, signed into law in November 2002, amended the Deepwater Port Act of 1974 to include offshore natural gas facilities. The legislation transferred jurisdiction for offshore natural gas facilities from the FERC to the Maritime Administration and the U.S. Coast Guard, both of which were at that time under the U.S. Department of Transportation. (The Coast Guard has since been moved to the Department of Homeland Security.)

The amendments in the Maritime Security Act of 2002 lowered the regulatory hurdles faced by potential developers of offshore LNG receiving terminals. Placing them under Coast Guard jurisdiction both streamlined the permitting process and relaxed regulatory requirements. Owners of offshore LNG terminals are allowed proprietary access to their own terminal capacity, removing what had once been a major stumbling block for potential developers of new LNG facilities. The Hackberry Decision, discussed below, has the same impact on onshore LNG facilities under FERC jurisdiction.

The streamlined application process under the new amendments promises a decision within 365 days of receipt of an application for construction of an offshore LNG terminal. Once the final public hearing on an application has been held, it must be either approved or denied within 90 days. The Maritime Administration will be responsible for reviewing the commercial aspects of the proposal, and the Coast Guard will consider safety, security, and environmental aspects.

Shortly after these changes went into effect, ChevronTexaco filed a preliminary application with the Coast Guard for its Port Pelican project, which was later approved. Plans for the project call for an LNG facility in 90 feet of water, with a baseload capacity of 800 million cubic feet per day. Subsequently, El Paso Natural Gas Company filed an application for its Energy Bridge project, which would use specialized tankers with on-board regasification equipment to offload regasified LNG through a submerged docking buoy into a pipeline to the mainland. AEO2004 incorporates the Deepwater Port Act amendments through reduced permitting costs and associated delays in such projects.

The Hackberry Decision

In December 2002, the FERC terminated open access requirements for new onshore LNG terminals in the United States, placing them on an equal footing with offshore terminals regulated under provisions of the Maritime Security Act of 2002. The FERC ruling, which granted preliminary approval to the proposed Dynergy/Sempra LNG terminal in Hackberry, Louisiana, is referred to as the Hackberry Decision. It authorized Hackberry LNG (now Cameron LNG) to provide services to its affiliates under rates and terms mutually agreed upon (i.e., market-based), rather than under regulated cost-of-service rates, and exempted the company from having to provide open access service. In essence, from a regulatory perspective, LNG import facilities will be treated as supply sources rather than as part of the transportation chain.

The LNG industry had been lobbying strongly for a relaxation of regulatory requirements, arguing that the FERC should focus on doing whatever it can to ensure that the United States has adequate natural gas supplies. Industry participants at a public conference hosted by the FERC in October 2002 on issues facing the natural gas industry maintained that the

Commission's open season [6] and open access requirements were a deterrent to the construction of new LNG terminals in the United States. They stressed that investors needed assurance that they would have access to terminal capacity, and that such assurance could not be given under the FERC's existing open season bidding requirements.

The FERC has specifically stated that it hopes the new policy will encourage the construction of new LNG facilities by removing some of the economic and regulatory barriers to investment. Existing terminals will continue to operate under open access and regulated rates, but FERC has indicated a willingness to allow them to modify their regulatory status as long as their existing customers are in agreement. AEO2004 incorporates the Hackberry Decision through reduced permitting costs and delays associated with LNG projects.

State Air Emission Regulations

Several States, primarily in the Northeast, have recently enacted air emission regulations that will affect the electricity generation sector. The regulations are intended to improve air quality in the States and assist them in complying with the revised 1997 National Ambient Air Quality Standards (NAAQS) for ground-level ozone and fine particulates. The affected States include Connecticut, North Carolina, Massachusetts, Maine, New Hampshire, New Jersey, New York, and Oregon. The regulations govern emissions of NO_x, sulfur dioxide (SO_2), carbon dioxide (CO_2), and mercury from power plants. Table 2 shows emissions of NO_x, SO_2, and CO_2 by electricity generators in the eight States and in the rest of the country. Comparable data on mercury emissions by State are not available.

Where firm compliance plans have been announced, State regulations are represented in *AEO2004*. For example, the SO_2 scrubbers, selective catalytic reduction (SCR), and selective non-catalytic reduction (SNCR) installations associated with the largest State program, North Carolina's "Clean Smokestacks Initiative," are included. As shown in Table 2, North Carolina accounts for nearly one-half of the emissions in the eight affected States. Overall, the *AEO2004* forecast includes 23 gigawatts of announced SO_2 scrubbers, 41.6 gigawatts of announced SCRs, and 4.5 gigawatts of announced SNCRs (both SCRs and SNCRs are NO_x removal technologies).

In addition to the existing regulations, Governor George Pataki of New York has announced proposed greenhouse gas reduction targets for the State of New York and he invited nine other States (Connecticut, Delaware, Maryland, Maine, New Hampshire, New Jersey, Pennsylvania, Rhode Island, and Vermont) to participate in a future "Northeast CO_2 cap and trade" program.

Table 3 summarizes current State regulatory initiatives on air emissions, and the following section gives brief descriptions of programs in the eight States that have enacted air emission regulations more stringent than Federal regulations. State-level initiatives to limit greenhouse gas emissions without directly regulating the electricity generation sector, which are not discussed here, include the following examples: California's CO_2 pollution standards for 2009 model vehicles and those sold later; Georgia's transportation initiative, focusing on expanding use of mass transit and other transportation sector measures; Minnesota's Releaf Program, which encourages tree planting as a way to reduce atmospheric CO_2 levels; Nebraska's carbon sequestration advisory committee, which proposes to sequester carbon through agricultural reform practices; North Carolina's program to develop new technologies for solid waste management practices that reduce emissions; Texas's renewable portfolio standard program; and Wisconsin's greenhouse gas emissions inventory.

Table 2. Emissions from electricity generators in selected States, 2002 (tons)

State	*SO_2*	*NO_x*	*CO_2*
Connecticut	*10,814*	*5,100*	*7,827,884*
Massachusetts	*90,726*	*28,500*	*21,486,936*
Maine	*2,022*	*1,154*	*5,784,562*
New Hampshire	*43,946*	*6,826*	*5,556,992*
New Jersey	*48,268*	*27,581*	*12,440,663*
New York	*231,875*	*69,334*	*51,293,393*
North Carolina	*462,993*	*145,706*	*72,866,548*
Oregon	*12,280*	*8,840*	*7,607,557*
Subtotal	*902,925*	*293,039*	*184,864,534*
Rest of country	*9,287,292*	*4,068,670*	*2,240,690,001*
Total	***10,190,216***	***4,361,709***	***2,425,554,535***
Percent of total for selected States	*8.86%*	*6.72%*	*7.62%*

Connecticut. The Connecticut "Abatement of Air Pollution" regulation was enacted in December 2000. It limits SO_2 and NO_x emissions from all NO_x budget program (NBP) sources that are more than 15 megawatts or require fuel input greater than 250 million Btu per hour [7]. The regulation applies to the electricity generation sector, the cogeneration sector, and industrial units. The NO_x limit is 0.15 pound per million Btu of heat input. The SO_2 limit is enforced in two phases. Under Phase I, the limit for all NBP sources is 0.5 percent sulfur in fuel or 0.55 pound per million Btu of heat input by January 2002. The Phase II limit applies to all NBP sources that are also Acid Rain Program Sources, and the limit is 0.3 percent sulfur in fuel and 0.33 pound per million Btu by January 2003.

In May 2003, the Connecticut State legislature passed legislation requiring coal-fired power plants to remove 90 percent of their mercury (or a maximum of 0.6 pound mercury emitted per trillion Btu input, which is equivalent to 0.005 to 0.007 pound per gigawatthour) by July 2008. The legislature has recommended that the State Department of Environmental Protection consider stricter limits by July 2012 [*8*].

Connecticut is developing a climate change action plan that is designed to help meet the New England

Table 3. Existing State air emissions legislation with potential impacts on the electricity generation sector

State	*Activities*	*Emissions limits*
Connecticut	*"Abatement of Air Pollution" regulations for electric utility, industrial cogeneration, and industrial units*	
	SO_2 emissions Phase I limit by 2002	*0.55 pound per million Btu input*
	SO_2 emissions Phase II limit by 2003	*0.33 pound per million Btu input*
	NO_x limit	*0.15 pound per million Btu input*
	Mercury limit by July 2008	*90% removal (or maximum of 0.6 pound mercury emitted per trillion Btu input, equivalent to 0.005-0.007 pound mercury per gigawatthour)*
Maine	*"An Act to Provide Leadership in Addressing the Threat of Climate Change," regulation for greenhouse gas emissions reduction from all sectors*	
	Greenhouse gas emissions by 2010	*At 1990 levels*
	Greenhouse gas emissions by 2020	*10% below 1990 levels*
	Greenhouse gas emissions in the "long term"	*75% to 80% below 2003 levels*
	Potential participant in Northeast CO_2 cap and trade program	
Massachusetts	*"Emissions Standards for Power Plants," multi-pollutant cap for existing power plants*	
	SO_2 emissions 1999: 6.7 pounds per megawatthour	
	SO_2 cap 2004 or 2006 (depending on compliance strategy)	*6.0 pounds per megawatthour*
	SO_2 cap 2006 or 2008 (depending on compliance strategy)	*3.0 pounds per megawatthour*
	NO_x emissions 1999: 2.4 pounds per megawatthour	
	NO_x cap 2004 or 2006 (depending on compliance strategy)	*1.5 pounds per megawatthour*
	CO_2 emissions (current): 2,200 pounds per megawatthour	
	CO_2 cap 2006 or 2008 (depending on compliance strategy)	*1,800 pounds per megawatthour*
New Hampshire	*"Clean Power Act" for existing fossil-fuel power plants*	
	SO_2 emissions 1999: 48,000 tons	
	SO_2 cap 2006	*7,289 tons*
	NO_x emissions 1999: 9,000 tons	
	NO_x cap 2006	*3,644 tons*
	CO_2 emissions 1990: 5,426 thousand tons	
	CO_2 emissions 1999: 5,594 thousand tons	
	CO_2 cap 2006	*5,426 thousand tons*
New Jersey	*Greenhouse gas emissions 1990: 136 million metric tons carbon dioxide equivalent*	
	Greenhouse gas emissions 2005	*3.5% below 1990*
New York	*Title 6 NYCRR Parts 237 and 238 applicable to electric utilities, cogenerators, and industrial units*	
	SO_2 Phase I limit January 2005, 25% below allocation	*197,046 tons*
	SO_2 Phase II limit January 2008, 50% below allocation	*131,364 tons*
	NO_x limit beginning in October 2004	*39,908 tons*
North Carolina	*"Clean Smokestacks Act" for existing coal-fired plants only*	
	SO_2 emissions 1999: 429,000 tons	
	SO_2 cap 2009	*250,000 tons*
	SO_2 cap 2013	*130,000 tons*
	NO_x emissions 1999: 178,000 tons	
	NO_x cap 2009	*56,000 tons*
Oregon	*CO_2 for new or expanded power plants*	*675 pounds per megawatthour*

Governors/Eastern Canadian Provinces goal for CO_2 reduction (stabilization of greenhouse gas emissions at 1990 levels by 2010, and a 10-percent reduction from 1990 levels by 2020). The State is also a potential participant in the Northeast CO_2 cap and trade program. Modifications are being made to the current NBP rules to provide incentives in the form of allowances for renewable energy and energy efficiency programs [*9*].

Maine. Maine enacted a climate change statute—"An Act to Provide Leadership in Addressing the Threat of Climate Change" (Public Law 2003, Chapter 237, H.P. 622-L.D. 845)—in May 2003. The statute requires the establishment of a greenhouse gas emissions inventory for State-owned facilities and State-funded programs and calls for a plan to reduce emissions to 1990 levels by 2010. The statute specifies that carbon emission reduction agreements must be signed with at least 50 businesses and nonprofit organizations by January 2006, and that Maine must participate in a regional greenhouse gas registry. The goals of the statute are a reduction of greenhouse gases to 1990 levels by January 2010, a reduction to 10 percent below 1990 levels by 2020, and a reduction to between 75 and 80 percent below 2003 levels "in the long term." It authorizes the Department of Environmental Quality to adopt a State climate action plan by July 2004 to meet the goals of the statute [*10*].

Massachusetts. The Massachusetts Department of Environmental Protection air pollution control regulations (310 CMR 7.29, "Emissions Standards for Power Plants") [*11*] apply to existing power plants in Massachusetts. They would affect six older power plants. There are two options for utilities to comply with the regulations: either "repower" (defined as replacing existing boilers with new ones that meet the environmental standards, switching fuel to low-sulfur coal, or switching from coal to natural gas); or choose a standard path that includes installing low-NO_x burners, installing SO_2 scrubbers, and installing SCR or SNCR equipment.

The rule offers an incentive for a fuel shift by delaying the compliance deadline to October 2008 for any facility choosing to repower. Plants using other techniques, such as pollution control equipment, must comply by October 2006. The SO_2 standard is 6.0 pounds per megawatthour by October 2004 (standard) or October 2006 (repowering) and 3.0 pounds per megawatthour by October 2006 (standard) or October 2008 (repowering). The NO_x standard is 1.5 pounds per megawatthour by October 2004 (standard) or October 2006 (repowering). The SO_2 and NO_x regulations are considered by the State to be more stringent than the Clean Air Act Amendments of 1990 would imply. Most of the facilities are choosing the repowering mode rather than the standard mode of compliance. Compliance plans have been submitted for the six power stations affected: Brayton Point, Salem Harbor, Somerset, Mount Tom, Canal, and Mystic [*12*].

The CO_2 standard annual facility cap is based on 3 years of data as of October 2004 (standard) or October 2006 (repowering) and an annual facility rate of 1,800 pounds CO_2 per megawatthour as of October 2006 (standard) or October 2008 (repowering). Credits for off-site reductions of CO_2 emissions can be obtained through carbon sequestration or renewable energy projects. The Massachusetts Department of Environmental Protection is developing regulations that would determine what projects could qualify as reductions. Greenhouse gas banking and trading regulations are also being developed. Plants that fail to achieve the reductions may purchase emissions credits. The governor of Massachusetts has sent a letter expressing interest in working with New York State to develop a cap and trade program for CO_2 emission reductions from power plants [*13*]. Data collection and feasibility assessment on mercury control are ongoing. Draft mercury regulations have been publicly released and are going through a comment period before consideration by the State legislature [*14*].

New Hampshire. New Hampshire has enacted legislation—the Clean Power Act (House Bill 284)—to reduce emissions of SO_2, NO_x, CO_2, and mercury from existing fossil-fuel-burning steam-electric power plants. Governor Jeanne Shaheen signed the Act into law in May 2002, and implementing regulations have been finalized [*15*]. The legislation applies to the State's three existing fossil-fuel power plants only and does not apply to new capacity. The plants must either reduce emissions, purchase emissions credits from other plants outside New Hampshire that have achieved such reductions, or use some combination of these strategies. Compliance plans submitted to the New Hampshire Department of Environmental Services (DES) are under review.

The SO_2 annual cap is 7,289 tons by 2006, which amounts to a 75-percent reduction from Phase II Acid Rain legislation requirements and an 85-percent reduction from 1999 emission levels (see Table 3). The NO_x annual cap is 3,644 tons by 2006, which amounts to a 60-percent reduction from 1999 emission levels. The CO_2 annual cap is 5,425,866 tons by

2006, which amounts to a 3-percent reduction from 1999 levels. The Governor of New Hampshire has sent a letter expressing interest in working with New York State to develop a cap and trade program for reducing CO_2 emissions from power plants.

The mercury cap is to be determined after the U.S. Environmental Protection Agency (EPA) establishes a Maximum Achievable Control Technology (MACT) standard for mercury control, but no later than March 31, 2004. Emissions allowances from Federal or regional trading and banking programs can be used to comply with the State cap. For CO_2 and mercury, early reductions can be banked for future use. NO_x allowances can be pooled but cannot be applied to emissions between May and September. SO_2 allowances obtained under the Federal acid rain program can be used against the cap. The statute includes incentives for investment in energy efficiency, new renewable energy projects, conservation, and load management. It does not apply to utilities that have installed "qualifying repowering technology" or replacement units meeting certain pollution control criteria [*16*].

New Jersey. New Jersey's goal is to reduce State-wide emissions of greenhouse gases from all sectors by 3.5 percent from 1990 levels by 2005. "Covenants" have been signed, pledging organizations to reduce their greenhouse gas emissions in accordance with the State goal [*17*]. In January 2002, the U.S. Department of Justice, the U.S. EPA, and the State of New Jersey obtained a Clean Air Act Consent Decree involving Public Service Enterprise Group Fossil, LLC (PSEG). In addition to a $1.4 million monetary penalty to be paid to the Federal Government [*18*], the settlement commits PSEG to reduce SO_2, NO_x, and particulate matter emissions on all its coal-fired units, to retire SO_2 and NO_x allowances, and to undertake other environmental projects. This is a part of the Prevention of Significant Deterioration/New Source Review (PSD/NSR) enforcement effort. The Governor of New Jersey has also sent a letter expressing interest in working with New York to develop a cap and trade program for CO_2 emission reductions from power plants.

New York. New York's "Acid Deposition Reduction Budget Trading Programs"—Title 6 NYCRR Parts 237 and 238—were approved by the State Environmental Board in March 2003 and became effective in May 2003 [*19*]. The NO_x regulations apply to electricity generators of 25 megawatts or greater, and the SO_2 regulations apply to all Title IV sources under the Clean Air Act [*20*], including electric utilities and other sources of SO_2 and NO_x, such as cogenerators and industrial facilities. NO_x emissions are limited to 39,908 tons beginning in October 2004. SO_2 emissions are limited in two phases: Phase I, beginning in January 2005, limits SO_2 emissions to 25 percent below Title IV allocations (197,046 tons), and Phase II, beginning in January 2008, increases the limits to 50 percent below Title IV allocations (131,364 tons) [*21*]. A governor's task force was established in June 2001 to recommend greenhouse gas limits. Further details on the recommendations of the Task Force are provided below.

North Carolina. The General Assembly of North Carolina has passed the Clean Smokestacks Act—officially called the Air Quality/Electric Utilities Act (S.B. 1078)—which requires emissions reductions from 14 coal-fired power plants in the State. Under the Act, North Carolina utilities must reduce NO_x emissions from 245,000 tons in 1998 to 56,000 tons by 2009 and SO_2 emissions from 489,000 tons in 1998 to 250,000 tons by 2009 and 130,000 tons by 2013. Progress Energy Carolinas, Inc., and Duke Power have submitted compliance plans to the North Carolina Department of Environment and Natural Resources and the North Carolina Utilities Commission. The utilities will comply with the Act by installing scrubbers and SNCR technology at their plants.

The Act requires the Department of Environment and Natural Resources to evaluate issues related to the control of mercury and CO_2 emissions and recommend the development of standards and plans to control them. In 2003, the Department of Air Quality has prepared a report on mercury [*22*] and CO_2 reductions for the State [*23*]. This is the first of three sets of reports submitted to the Environmental Management Commission and the Environmental Review Commission. The subsequent reports are due in September 2004 and September 2005. The objective of the 2003 report is to provide a general background on the topic of climate change and to define the scope of efforts needed to meet the legislative requirements. The 2004 and 2005 reports will build on this background, report on any developments in the Federal Government, and recommend courses of action that may follow. A proposed workshop being planned for spring 2004 will form the basis for the September 2004 report.

The Act also requires North Carolina to persuade other States and power companies to reduce their emissions to similar levels and on similar timetables. The Act specifically mentions that discussions should be held with the Tennessee Valley Authority (TVA) to determine its emission reduction policies. A meeting was held between the Department of Environment and Natural Resources/Department of Air Quality and TVA in August 2002 to discuss actions planned by TVA that would be comparable to the Clean Smokestacks Act. TVA presented its plans to add scrubbers to five additional power plants, primarily in the eastern portion of the TVA system, beginning with its Paradise plant in 2006. TVA plans to complete installation of the new scrubbers by 2010. TVA also plans to install the first 8 SCR systems for NO_x control and to have 25 boiler units controlled by 2005, which will reduce NO_x emissions during the ozone season by 75 percent. Duke Power and Progress Energy have reported compliance costs for SO_2 and NO_x control. For the North Carolina utilities, SNCR costs range from $4.93 to $63.70 per kilowatt, and scrubber costs range from $113 to $414 per kilowatt [*24*].

Oregon. Oregon has established its first formal State standards for CO_2 emissions from new electricity generating plants. The standards apply to power plants and non-generating facilities that emit CO_2. The Oregon Energy Facility Siting Council originally adopted the rules pursuant to House Bill 3283, which was passed by the Oregon legislature in June 1997, and has subsequently updated the rules, most recently in April 2002 [*25*]. For baseload natural gas plants and non-baseload plants, the standard is CO_2 emission rates of 675 pounds per megawatthour, 17 percent below the rate for the most efficient natural-gas-fired plants currently in operation in the United States. The Council has not set CO_2 emission standards for baseload power plants using other fossil fuels.

The Council's definition of a natural-gas-fired facility allows up to 10 percent of the expected annual energy to be provided by an alternative fuel, most likely distillate fuel. Proposed facilities may meet the requirement through cogeneration, using new technologies, or purchasing CO_2 offsets from carbon mitigation projects. It is possible to offset all excess CO_2 emissions through cogeneration offsets alone, and there are no limitations on the geographic locations or types of CO_2 offset projects. The Council has set a monetary value that the generators may pay to buy offsets ($0.85 per short ton CO_2, equivalent to $3.12 per ton carbon, set in September 2001) [*26*]. This equates to an offset cost of 0.88 mills per kilowatthour [*27*].

New Source Review

On August 27, 2003, the EPA issued a final rule defining certain power plant and industrial facility activities as "routine maintenance, repair and replacement," which are not subject to new source review (NSR) under CAAA90. As stated by the EPA, "these changes provide a category of equipment replacement activities that are not subject to Major NSR requirements under the routine maintenance, repair and replacement (RMRR) exclusion" [*28*]. Essentially this means that power plants and industrial facilities engaging in RMRR activities will not be required to obtain State or EPA approval for those activities and will not have to install the "best available" emissions control technologies that might be required if NSR were triggered.

Although the RMRR exclusion is not new, in the past it has been evaluated on a case-by-case basis. The new rule attempts to give affected entities some regulatory clarity by defining the specific activities that qualify for the exclusion. The new rule "specifies that the replacement of components of a process unit with identical components or their functional equivalents will come within the scope of the exclusion, provided the cost of replacing the component falls below 20 percent of the replacement value of the process unit of which the component is a part, the replacement does not change the unit's basic design parameters, and the unit continues to meet enforceable emission and operational limitations" [*29*]. Knowing the costs and scope of any changes they are considering, industrial and power plant facility owners will be able to determine whether they might trigger NSR.

The potential impact of the new rule is unknown. During its development, some observers argued that uncertainty about whether actions under consideration would trigger NSR had led facility owners to forgo investments that might improve the efficiency, reliability, and/or capacity of their units, and that the change in rules could lead to significant increases in the efficiency of coal-fired power plants and their electricity production [*30*].

Even without the rule change, however, coal-fired generation has been increasing. For example, between 1990 and 2002 coal-fired generation in the electric power sector increased by 21 percent, while coal-fired capacity increased by only 2 percent. Clearly, operators have been able to maintain their coal-fired power plants and increase their output under the old rules. These revisions should enable coal plant operators to continue maintaining their plants and increase their use with less worry about triggering NSR. In *AEO2004*, coal-fired generation is projected to increase significantly as existing plants are used more intensively and new plants are added. No explicit changes to address the impacts of the new NSR rule have been made in *AEO2004*. As more data become available, they will be included in future *AEO*s.

The Energy Policy Act of 2003

The U.S. House of Representatives passed H.R. 6.EH, The Energy Policy Act of 2003 (EPACT03), on April 11, 2003. The Senate passed H.R. 6.EAS (the same bill it had passed in 2002) on July 31, 2003. A Conference Committee was convened to resolve differences between the two bills, and a conference report was approved and issued on November 17, 2003 [*31*]. The House approved the conference report on November 18, 2003, but a Senate vote on cloture failed, and further action has been delayed at least until January 2004.

Consistent with the approach adopted in the *AEO* to include only Federal and State laws and regulations in effect, the various provisions of EPACT03 are not represented in the *AEO2004* projections. This discussion focuses on selected provisions of the current version of EPACT03 that have, in EIA's estimation, significant potential to affect energy consumption and supply at the national level. Proposed provisions in the following areas are addressed:

- Tax credits, grants, low-income subsidies, mandatory standards, and voluntary programs that act to reduce the cost and use of energy in the buildings sectors
- Industrial programs providing tax credits for combined heat and power (CHP) generation, blended cement, and voluntary programs to reduce energy intensity
- Tax credits for alternative fuel vehicles
- Establishment of a renewable fuels standard
- Elimination of the use of methyl tertiary butyl ether (MTBE) in gasoline
- Elimination of oxygen content requirements for reformulated gasoline
- Creation of tax deductions and credits for small refiners to encourage the production of low-sulfur diesel fuels
- Ethanol and biodiesel tax credits
- Extension of royalty relief to natural gas production from deep wells on existing leases in shallow waters
- Establishment and funding of a research program for ultra-deepwater and nonconventional natural gas and other petroleum resources from royalty payments
- Section 29 tax credits for nonconventional fuels production
- Assistance for constructing the Alaska Natural Gas Pipeline
- Establishment of a series of tax credits for natural gas gathering, distribution, and high-volume pipelines and gas processing facilities
- Provisions to improve the reliability of the electricity transmission grid
- Tax incentives and other provisions to encourage generation from renewable and nuclear fuels.

End-Use Energy Demand

EPACT03 includes tax incentives, standards, voluntary programs, and other miscellaneous provisions that affect the end-use demand sectors. Provisions that affect the residential and commercial sectors (the buildings sectors) are discussed together, because many of the legislative proposals affect both sectors.

Buildings

EPACT03 contains several provisions designed to mitigate future energy consumption in the buildings sectors. They encompass a multifaceted policy approach, employing tax credits, grants, low-income subsidies, mandatory standards, and voluntary programs in an attempt to reduce both expenditures for and use of residential and commercial energy. Each of these approaches can yield different results in terms of program effectiveness.

Of all the provisions included in EPACT03, only the mandatory standards for products such as torchiere lighting and traffic signals (Section 133) force a direct impact on buildings sector energy use; the other provisions require homeowners, occupants, builders, and/or government officials to pursue a specific course of action to spur measurable energy savings. In terms of proposed tax credits, for the next 3 years, builders can claim $1,000 to $2,000 for each home built that meets certain efficiency criteria (Section 1305). Likewise, homeowners who upgrade the building envelopes of existing homes can claim a 20-percent tax credit (up to $2,000) from 2004 to 2006 (Section 1304).

Other provisions include production tax credits for efficient refrigerators and clothes washers through 2007, as well as credits for the installation of fuel cells, CHP systems, and solar thermal and photovoltaic equipment (Sections 1307, 1303, 1306, and 1301). Commercial businesses can also claim a tax deduction of $1.50 per square foot for expenditures on energy-efficient building property (Section 1308). In terms of subsidies, EPACT03 directs funding increases over the next several years for both the Low Income Home Energy Assistance Program (LIHEAP) and the Department of Energy's weatherization program (Sections 121 and 122), which could reduce future energy use by allowing more low-income homes to be weatherized. Other provisions update Executive Order mandates regarding Federal purchasing requirements and energy intensity reductions (Sections 102 through 104); allow for energy conservation measures in congressional buildings (Section 101); and establish a program to install photovoltaic energy systems in public buildings over the next 5 years (Section 205).

Several provisions of EPACT03 either are less specific in terms of what the future law might require or are difficult to assess and, therefore, have less certain impacts. They include the establishment of test procedures for several products (Section 133), programs to educate homeowners on the importance of maintaining heating and cooling equipment (Section 132), and grants to States for rebates on the purchase of energy-efficient products (Section 124).

Industrial

The industrial sector provisions of EPACT03 include tax credit programs for CHP, blended cements, and voluntary programs to reduce industrial energy intensity. Section 1306 would extend the current 10-percent business credit for solar power generation equipment to CHP systems. Qualifying equipment must have electrical capacity of not more than 15 megawatts or mechanical energy no greater than 2,000 horsepower. Qualifying equipment must produce at least 20 percent of its useful output as thermal energy and at least 20 percent as electricity. Such equipment must also have a system efficiency of at least 60 percent. The credit would be effective from December 31, 2003, to January 1, 2007. The tax credit would create an incentive to increase CHP generation, but that incentive would be diminished by the relatively small size limit for qualifying facilities. Further, the short time frame of the credit probably would limit CHP expansion to plants that would have been built in its absence.

Section 110 would encourage Federal agencies to require greater use of blended cements but does not specify the amount of blending that would be allowed. Generally, increasing the recovered mineral component would decrease the amount of new cement production required to produce a given output of concrete.

Section 107 would authorize the Secretary of Energy to enter into voluntary agreements with one or more persons in the industrial sector to reduce their energy intensity by a significant amount compared with recent years. This program appears similar to the existing Climate Vision program, which is part of the Administration's effort to reduce greenhouse gas intensity by 18 percent over the next decade [*32*].

Transportation

Present law provides a maximum tax deduction for alternative fuel motor vehicles of $50,000 for a truck or van weighing over 26,000 pounds and $2,000 for a vehicle weighing 10,000 pounds or less. In addition, current law provides a 10-percent tax credit toward the cost of a qualified electric vehicle, up to $4,000. The tax deductions and credit are scheduled to be phased out between January 1, 2002, and December 31, 2004.

Section 1317 of EPACT03 would extend the existing alternative fuel motor vehicle deduction through December 31, 2006; repeal an existing credit for electric fuel cell vehicles; and provide credits for the purchase of fuel cell powered motor vehicles, hybrid motor vehicles, mixed-fuel motor vehicles, and advanced lean-burn technology motor vehicles. Unused credits could be carried forward 20 years and would apply to hybrid and advanced lean-burn technology vehicles placed in service before 2008 and to fuel cell vehicles placed in service before 2012. Property placed in service after the enactment of EPACT03 could also receive the tax credits. Credits for hybrid and advanced lean-burn technology vehicles would be phased out after cumulative sales of the specific technology exceeded 80,000 units. Section 1318 specifies allowable tax credits by vehicle and fuel type.

Although EPACT03 does not prescribe a change in corporate average fuel economy (CAFE) standards, Section 772 sets out specific items that the Secretary of Transportation should consider when evaluating a potential increase, including technological feasibility, economic practicability, the effect of other government motor vehicles standards on fuel economy, the need of the United States to conserve energy, the effects of fuel economy standards on safety, and the effect of compliance on automobile industry employment. Further, Section 774 would require the Administrator of the National Highway Traffic Safety Administration to initiate a study no later than 30 days after enactment of EPACT03 to look at the feasibility and effects of requiring a significant percentage reduction in automobile fuel consumption beginning in model year 2012.

Petroleum, Ethanol, and Biofuel Tax Provisions

Numerous provisions of EPACT03 would affect the supply, composition, and refining of petroleum and related products. The major issues include:

- Establishment of a renewable fuels standard
- Elimination of MTBE
- Elimination of the oxygen content requirement for reformulated gasoline
- Small refiner deductions to encourage investment in low-sulfur fuel production
- Ethanol and biofuel tax provisions.

Renewable Fuels Standard

Section 1501 of EPACT03 requires the production and use of 3.1 billion gallons of renewable fuel in 2005, increasing to 5.0 billion gallons by 2012. For calendar year 2013 and each year thereafter, the minimum renewable fuels required would be determined by the volume percentage of 5.0 billion gallons over the total gasoline sold in the Nation in 2012. Small refineries with a capacity not exceeding 75,000 barrels per calendar year, and the States of Alaska and Hawaii, are exempted from the renewable fuels standard. Both ethanol and biodiesel are considered as renewable fuels, with a 1.5-gallon credit toward the renewable fuels standard for every gallon of biomass ethanol produced and a 2.5-gallon credit if the biomass ethanol is derived from agricultural residue or is an agricultural byproduct. A renewable fuels credit program would allow refiners, blenders, and importers flexibility to comply with the renewable fuels standard across geographical regions and successive years.

MTBE Phaseout

Section 1502 exempts MTBE and renewable fuels used in motor vehicles from being deemed "defective products." However, the exemption does not "affect the liability of any person for environmental remediation costs, drinking water contamination, negligence for spills or other reasonably foreseeable events, public or private nuisance, trespass, breach of warranty, breach of contract, or any other liability other than liability based on a claim of defect product." Section 1503 provides for transition assistance up to $250 million per year between 2005 and 2012 to merchant MTBE producers moving to production of iso-octane, iso-octene, alkylates, or renewable fuels. Section 1504 prohibits the use of MTBE after December 31, 2014, but trace quantities not exceeding 0.5 percent by volume are allowed. The Governor of a State may submit a notification to the EPA authorizing the continued use of MTBE, and the President of the United States may also void the MTBE restrictions by June 30, 2014, based on findings by the National Academy of Sciences on the costs and benefits of motor fuel additives, including MTBE.

Oxygen Requirement for Reformulated Gasoline

Section 1506 would eliminate the oxygen content requirement for reformulated gasoline. It would take effect 270 days after enactment of EPACT03, except for California, which would receive the exemption immediately. Volatile organic compound (VOC) Control Regions 1 and 2 for reformulated gasoline would be consolidated by eliminating the less stringent requirements applicable to gasoline designated for VOC Control Region 2 (northern).

Small Refiners

Section 1324 allows small refiners to deduct 75 percent of qualified capital expenditures in the year of the expense for costs related to compliance with the EPA's Tier 2 low-sulfur gasoline and highway diesel fuel requirements. The provision applies as a deduction for expenses incurred in a taxable year beginning after December 31, 2002. Gasoline sulfur reductions could be phased in between 2004 and 2007; diesel sulfur reductions would take effect starting in mid-2006.

Section 1325 of EPACT03 provides for a 5-cent-per-gallon tax credit to small refiners of low-sulfur diesel fuel (15 ppm or less) for expenses incurred after December 31, 2002. The total amount of the credit is limited to 25 percent of qualified capital costs incurred to reach compliance with EPA diesel fuel regulations, and no credit is allowed until the refiner obtains certification of compliance. The credit is reduced *pro rata* for refiners processing over 155,000 barrels per day but less than 205,000 barrels per day. It applies to organizations with no more than 1,500 individuals engaged in refinery business operations on any day during the year. For cooperative organizations, the credit can be apportioned among members. The effective period runs from January 1, 2003, to one year after the date the refiner must comply with EPA regulations, but no later than December 31, 2009.

Ethanol and Biofuel Tax Provisions

The current gasoline and highway diesel fuel excise taxes are 18.4 and 24.4 cents per gallon, respectively.

For each gallon of highway fuel, 0.1 cents is deposited in the Leaking Underground Storage Tank Trust Fund, and the balance is deposited in the Highway Trust Fund. Gasoline blended with 10 percent ethanol receives an excise tax reduction of 5.2 cents per gallon. Gasoline blended with 5.7 percent or 7.7 percent ethanol receives a proportionally smaller excise tax reduction. Under current law, if gasoline is blended with ethanol, the General Fund receives 2.5 cents, the Leaking Underground Storage Tank Trust Fund receives 0.1 cent, and the Highway Trust Fund receives the remainder.

Section 1314 would establish a biodiesel fuels credit analogous to the existing alcohol fuels income tax credit. A biodiesel mixture tax credit of 50 cents per gallon of biodiesel produced from recycled oil or $1 per gallon of biodiesel produced from virgin oil or virgin animal fat applies to biodiesel blended with petroleum diesel. A biodiesel credit in the same amount applies to each gallon of neat biodiesel. A taxpayer's biodiesel fuels tax credit is the sum of the biodiesel mixture credit and the biodiesel credit and is claimed against business income tax. The credit would be effective from December 31, 2003, through December 31, 2005.

Section 1315 would give fuel blenders the options of the alcohol fuel mixture excise tax credit and the biodiesel fuel mixture excise tax credit. Gasoline blended with renewable-source alcohol or ethers produced from renewable-source alcohol would be taxed at the full 18.4 cents per gallon. Diesel blended with biodiesel would be taxed at the full 24.4 cents per gallon. A tax credit of 52 or 51 cents per gallon of ethanol blended into gasoline or used to produce ethyl tertiary butyl ether blended into gasoline would be paid out of the General Fund. Receipts to the Highway Trust Fund would not be reduced by the use of ethanol in gasoline if blenders choose these credits. The credit is 60 cents per gallon of alcohol other than ethanol (such as methanol) derived from renewable sources. The excise tax credit for biodiesel is 50 cents per gallon of biodiesel from recycled oil or $1 per gallon of biodiesel from virgin oil or virgin animal fat. The excise tax credits cannot be claimed for alcohol or biodiesel for which an income tax credit is claimed or which are taxed at a reduced excise tax rate. The new alcohol excise tax credits would be available through December 31, 2010, and the new biodiesel excise tax credit would be available through December 31, 2005.

The current alcohol fuels income tax credit includes the alcohol mixture credit, the alcohol credit, and the small ethanol producer credit. Gasoline blended with ethanol qualifies for an alcohol mixture credit of 52 or 51 cents per gallon. Gasoline blended with an alcohol other than ethanol qualifies for an alcohol mixture credit of 60 cents per gallon. Alcohol tax credits in the same amount apply to fuel alcohols not blended with gasoline. A small ethanol producer qualifies for an additional credit up to 10 cents per gallon for annual production of 15 million gallons or less. Small ethanol producers currently cannot have production capacity above 30 million gallons per year. Section 1313 would raise the capacity limit to 60 million gallons per year. Section 1315 would move the expiration date of the alcohol fuels income tax credit from December 31, 2007, to December 31, 2010.

Natural Gas Supply Provisions

EPACT03 includes a number of provisions that would affect natural gas supply, including:

- Extension of royalty relief to natural gas production from deep wells in shallow waters
- Establishment of a research program covering ultra-deepwater offshore and unconventional natural gas and petroleum resources and funding from existing royalties
- Extension and modification of the Section 29 tax credit for nonconventional production
- Assistance for constructing the Alaska Natural Gas Pipeline
- Tax incentives for natural gas gathering and distribution
- Tax incentives for high-volume natural gas pipelines and gas processing facilities.

Royalty Relief for Natural Gas Production from Deep Wells in the Shallow Waters of the Gulf of Mexico

Section 314 of EPACT03 would authorize the Secretary of Energy to publish a final regulation to complete the rulemaking begun by the Notice of Proposed Rulemaking entitled "Relief or Reduction in Royalty Rates—Deep Gas Provisions," published in March 2003. The rule would grant various levels of royalty relief for wells drilled within the first 5 years of a lease in the shallow waters (less than 200 meters) of the Gulf of Mexico. The minimum volume of production with suspended royalty payments is 15 billion cubic feet for wells drilled to at least 15,000 feet and 25 billion cubic feet for wells drilled to more than 18,000 feet. In addition, unsuccessful wells drilled to a depth of at least 15,000 feet would receive a royalty tax credit for 5 billion cubic feet of natural gas. Credits could be received for up to two wells.

Section 314 would further grant royalty suspension volumes of not less than 35 billion cubic feet from ultra-deep wells on leases issued before January 1, 2001. An ultra-deep well is defined as a well drilled to at least 20,000 feet.

Funding and Establishment of a Research Program for Ultra-Deepwater and Unconventional Natural Gas and Other Petroleum Resources

Sections 941 through 949 would provide for the establishment of a research program covering the ultra-deepwater offshore and unconventional natural gas and petroleum resources (onshore) to advance activities related to development, demonstration, and commercialization of new technologies.

A separate fund will be established in the U.S. Treasury under this provision. Program funding will consist of $150 million annually from Federal royalties, rents, and bonuses for each fiscal year from 2004 through 2013. In addition, another $50 million for each corresponding year is authorized is to be appropriated by Congress, and the funds will remain available until expended. Total program impacts range from $1.5 billion to $2.0 billion over the 10-year period, representing more than a doubling of current annual funding for research.

Amounts obligated from the fund will be allocated in each fiscal year as follows. One-half of the funds shall be for activities under Section 942 for an ultra-deepwater program. A nonprofit, tax-exempt consortium will be selected and awarded a contract to perform authorized research activities in this offshore area. The next 35 percent of the funds are allotted for activities under Section 943(d)(1), which includes work related to coalbed methane, deep drilling, natural gas production from tight sands, stranded gas, innovative exploration and production techniques, enhanced recovery techniques, and environmental mitigation of unconventional natural gas and exploration and production of other petroleum resources. The next 10 percent of the funds shall be for activities under Section 943(d)(2) and awarded to consortia of small producers focusing on changes in complex geology and reservoirs, low reservoir pressure, unconventional natural gas reservoirs in coalbeds, deep reservoirs, tight sands, and shales as well as unconventional oil reservoirs in tar sands and oil shales. The remaining 5 percent of the funds are allocated under Section 941(d) to corresponding research activities at the National Energy Technology Laboratory.

Extension and Modification of the Section 29 Tax Credit for Producing Fuel from a Nonconventional Source

Section 1345 of EPACT03 would extend and modify the Section 29 tax credit for producing fuel from nonconventional sources. It would allow a credit of $3 (indexed for inflation with 2002 as the base year) per barrel (or Btu equivalent) for production from all nonconventional sources except landfills for 4 years of production prior to 2010 for new wells placed in service through 2006. Production from existing wells (drilled in 1980-1992), previously eligible through 2002, would also be eligible for the credit through 2006. For landfills regulated by the EPA there would be a credit of $3 for facilities placed in service after June 30, 1998, and before January 1, 2007. These facilities would be eligible for 5 years of credit. The credit in Section 1345 would be limited to an average daily production of 200,000 cubic feet of gas (or oil equivalent) per well or facility. The credit would be fully effective when the price of crude oil is $35 per barrel or less and would phase out gradually as the price rises to $41 per barrel.

Assistance for Constructing the Alaska Natural Gas Pipeline

Section 386 of EPACT03 would give the Secretary of Energy authority to issue Federal loan guarantees for any natural gas pipeline system that carries Alaskan natural gas to the border between Alaska and Canada south of 68 degrees north latitude. This authority would expire 2 years after the final certificate of public convenience and necessity is issued. The guarantee would not exceed: (1) 80 percent of total capital costs (including interest during construction); (2) $18 billion dollars (indexed for inflation at the time of enactment); or (3) a term of 30 years. Other assistance for construction of the Alaska Natural Gas Pipeline would be provided by the tax incentives for natural gas gathering, high-volume natural gas pipelines, and gas processing summarized below.

Tax Incentives for Natural Gas Gathering and Distribution

Section 1321 would provide a 7-year recovery period for natural gas gathering lines, as opposed to the current 15-year recovery period, for tax purposes. It also would allow for alternative minimum tax relief by not adjusting the allowable amount of depreciation. The treatment would apply to property placed in service after the date of enactment. The Joint Committee on Taxation estimates the negative effect on the budget from the provision at $16 million from 2004 to 2013.

Section 1322 would provide a 15-year recovery period for natural gas distribution lines, as opposed to the current 20-year recovery life available for taxpayers. The provision would be effective for property placed in service after the date of enactment.

Tax Incentives for High-Volume Natural Gas Pipelines and Gas Processing Facilities

Section 1355 would allow a 7-year recovery period for natural gas pipelines with a pipe diameter of at least 42 inches, and any related equipment, as opposed to the current 15-year recovery life available for taxpayers. The provision would be effective for property placed in service after the date of enactment. An Alaska pipeline to Canada is expected to satisfy the 42-inch requirement.

Section 1356 would extend the 15-percent tax credit currently applied to costs related to enhanced oil recovery to construction costs for a gas treatment plant that supplies natural gas to a 1 trillion Btu per day pipeline and produces carbon dioxide for injection into hydrocarbon-bearing geological formations. A gas treatment plant on the North Slope that feeds gas into an Alaska pipeline to Canada could be built to satisfy this requirement. The provision would be effective for costs incurred after 2003.

Electricity Provisions

EPACT03 includes provisions targeted at improving the reliability and operation of the electricity transmission grid; investment tax credits for "basic" and "advanced" clean coal generating technologies; tax provisions, targeted programs, and changes in regulatory structure to support the introduction of renewable electricity generation; and nuclear production tax credits.

Reliability and Operation of the Grid

The electricity title of EPACT03 contains numerous provisions aimed at improving the reliability and operation of the electricity grid, encouraging additional investment in critical grid infrastructure, and revising rules on utility ownership structure and power purchase requirements. For example, to improve reliability, it calls for the creation of mandatory grid reliability standards to replace the voluntary standards that exist today. These standards would be administered by new "electric reliability organizations," which are to be certified by the Federal Energy Regulatory Commission (FERC) and responsible for developing and enforcing reliability standards for their regions. Subject to FERC approval, electric reliability organizations can propose and modify reliability standards and issue fines to those who violate them.

To improve grid operation, EPACT03 calls for open nondiscriminatory access to the grid for all market participants. In other words, transmission-owning utilities are required to offer grid services to others under the same terms and conditions that they provide for themselves. The bill would call for FERC to reconsider its standard market design, and no final rule would be issued before October 31, 2006. However, through a sense of the Congress provision, utilities engaging in interstate commerce would be encouraged to voluntarily join regional transmission organizations. The bill states that regional transmission organizations are needed "in order to promote fair, open access to electric transmission service, benefit retail consumers, facilitate wholesale competition, improve efficiencies in transmission grid management, promote grid reliability, remove opportunities for unduly discriminatory or preferential transmission practices, and provide for the efficient development of transmission infrastructure needed to meet the growing demands of competitive wholesale power markets."

To stimulate investment in the Nation's transmission grid, the bill would give the Secretary of Energy the authority to designate national interest electric transmission corridors in areas experiencing transmission constraints or congestion. Once an area has been designated a national interest electric transmission corridor, within certain limitations, the FERC could issue a permit to modify existing or construct new transmission infrastructure. The goal of these provisions is to expedite the review, permitting, and construction of needed grid enhancements. The FERC would also be required to develop incentive rate structures for transmission pricing and to provide incentives for investments in advanced transmission equipment.

EPACT03 also calls for key changes in the Public Utility Holding Company Act of 1935 (PUHCA) and the Public Utility Regulatory Policies Act of 1978 (PURPA). PUHCA places significant limitations on the corporate structure and geographic scope of utility companies. It does not allow utility holding companies to own noncontiguous utilities and limits their investments outside the utility business. EPACT03 would repeal PUHCA but require that public utility holding companies provide Federal and State regulators access to their books. PURPA was enacted to promote alternative energy sources and energy efficiency, and to diversify the electric power industry. One of its key provisions required utilities to purchase power from qualifying cogeneration and small power production facilities. EPACT03 would remove the purchase requirement for new qualifying facilities, provided that the facility has open access to transmission services and wholesale energy markets.

Key Coal-Fired Electricity Provisions

EPACT03 provides investment tax credits for two specific categories of new coal-fired generating capacity. New coal-fired generating units employing "basic" clean coal technologies—such as advanced pulverized coal, fluidized bed, or integrated gasification combined cycle—are eligible for a tax credit that amounts to 15 percent of the basis of the property placed in service during a specific year. The tax credit for this category of coal plants applies to new facilities placed in service before January 1, 2014, and is limited to a national cap of 4,000 megawatts.

New coal-fired generating units employing "advanced" clean coal technologies are eligible for a tax credit that amounts to 17.5 percent of the basis of the property placed in service during a specific year. The "advanced" technologies include primarily the same technologies specified for the "basic" category, but they must meet both a higher standard for energy conversion efficiency and a cap on carbon emissions. The tax credit for this category of coal plants applies to new facilities placed in service before January 1, 2017, and is limited to a national cap of 6,000 megawatts.

Key Renewable Electricity Provisions

EPACT03 contains three types of provision that would affect renewable electricity markets: tax provisions, authorized programs, and changes to regulatory structures. The primary tax provisions relate to the renewable electricity production tax credit, which currently provides a tax credit of 1.8 cents per kilowatthour for 10 years from the initial online date of wind energy and qualifying biomass facilities entering service by December 31, 2003. EPACT03 would extend the eligibility period for the credit through December 31, 2006, and expand the program to include new biomass feedstocks, biomass co-firing facilities, geothermal facilities, solar power, and power from small irrigation systems. Facilities using "closed-loop" biomass supplies (energy crops grown specifically for energy production), either in dedicated use or in co-firing, would be eligible for the full credit value, but facilities using "open-loop" biomass resources (waste or byproducts from other processes) would receive a credit reduced by 33 percent for the first 5 years of operation from the initial online date. Co-firing facilities would receive the credit pro-rated to the thermal content of the biomass fuel. The tax credit and payment period would also be reduced for some of the other newly eligible technologies. Also, the credit would be allowed to reduce Alternative Minimum Tax payments, which should increase its value to project owners subject to Alternative Minimum Tax liability.

Authorized programs, including direct subsidies, research and development activities, and other programs to support renewable electricity, would be established with maximum allowable funding levels; however, actual execution of the programs would depend on annual budget appropriations. Newly authorized programs would include a direct production incentive payment for some new and incremental hydroelectric power facilities; a direct subsidy to encourage the use of forest thinnings for power production; and new research and development programs, such as the use of concentrating solar power to produce hydrogen.

Changes to regulatory structures would affect both hydroelectric licensing and geothermal leasing. The hydroelectric licensing revisions would allow license applicants to propose alternatives to proposed Federal agency fishway and other license conditions. Leasing and royalty procedures for use of geothermal resources on Federal lands would also be streamlined.

Nuclear Electricity Production Tax Credit

EPACT03 introduces a production tax credit for generation from advanced nuclear power facilities, similar to that in existence for renewables. The provision provides a tax credit of 1.8 cents per kilowatthour for the first 8 years of operation by qualified nuclear facilities. (Unlike the renewable provision, the credit is not adjusted for inflation.) Qualifying facilities must enter service after enactment of the bill and by December 31, 2020. There is a national capacity limitation of 6,000 megawatts; the bill does not specify the allocation of the limit but leaves it to the discretion of the Secretary of Energy. The provision also puts a limit of $125 million per 1,000 megawatts of capacity on the annual credit that can be received by any facility.

Issues in Focus

Outlook for Labor Productivity Growth

The *AEO2004* reference case economic forecast is a projection of possible economic growth, from the short term to the longer term, in a consistent framework that stresses demand factors in the short term and supply factors in the long term [*33*]. Productivity is perhaps the most important concept for the determination of employment, inflation, and supply of output in the long term. Productivity is a measure of economic efficiency that shows how effectively economic inputs are converted into output.

Advances in productivity—that is, the ability to produce more with the same or less input—are a significant source of increased potential national income. The U.S. economy has been able to produce more goods and services over time, not only by requiring a proportional increase of labor time but also by making production more efficient. To illustrate the importance of productivity improvements, on the eve of the American Revolution, U.S. gross domestic product (GDP) per capita stood at approximately $765 (in 1992 dollars) [*34*]. Incomes rose dramatically over the next two centuries, propelled upward by the Industrial Revolution, and by 2002 GDP per capita had grown to $30,000 (1992 dollars). Productivity improvements played a major role in the increase in per capita GDP growth.

Productivity is measured by comparing the amount of goods and services produced with the inputs used in production:

- *Labor productivity*—output per hour of all persons—is the ratio of the output of goods and services to the labor hours devoted to the production of that output; it is the most commonly used productivity measure. Labor is an easily identified input to virtually every production process. For the U.S. business sector, labor cost represents about two-thirds of the value of output produced. Increases in labor productivity allow for comparable gains in profits and/or compensation without putting upward pressures on output prices. When labor productivity grows, the economy is able to produce more with the same number of workers.
- *Multifactor productivity* reflects output per unit of some combined set of inputs. A change in multifactor productivity reflects the change in output that cannot be accounted for by the change in combined inputs. As a result, multifactor productivity measures reflect the joint effects of many factors, including new technologies, economies of scale, managerial skill, and changes in the organization of production.

The U.S. Department of Labor, Bureau of Labor Statistics (BLS), is responsible for developing official productivity statistics for the United States. BLS publishes four sets of productivity measures for major sectors and subsectors of the U.S. economy:

- Quarterly and annual output per hour and unit labor costs for the U.S. private business, private nonfarm business, and manufacturing sectors. These are the productivity statistics most often cited by the national media.
- Annual measures for output per hour and unit labor costs for 3-, 4-, 5-, and 6-digit North American Industry Classification System (NAICS) industries in the United States, with complete coverage in manufacturing and in retail trade, as well as some coverage in other sectors.
- Multifactor productivity indexes for the private business, private nonfarm business, and manufacturing sectors of the economy.
- Multifactor productivity indexes for 2- and 3-digit Standard Industrial Classification (SIC) manufacturing industries, such as the railroad transportation industry, the air transportation industry, and the utility and natural gas industry. These include indexes for total manufacturing and for 20 2-digit SIC manufacturing industries on an annual basis, which compare real value-added output measures to aggregate measures of input: labor, capital, energy, non-energy materials, and purchased business services [*35*].

In the *AEO2004* reference case, productivity growth in the nonfarm business sector is projected to average 2.25 percent annually from 2002 to 2025. The low and high macroeconomic growth cases project average annual growth of 1.82 percent and 2.65 percent, respectively. As discussed below, the range of productivity growth covered by the three cases is within the range of historical experience as well as what is projected for the future by various experts in the productivity field. Figure 8 shows 5-year average annual growth rates for the three cases.

Estimates of Historical Productivity Growth and Their Determinants

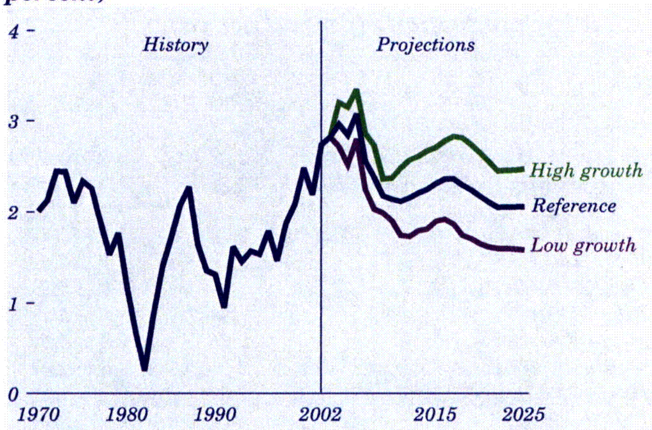
Productivity Growth up to 1995

For the period 1917-1927, labor productivity growth averaged 3.8 percent per year, the highest rate for any comparable 10-year period for the U.S. economy [*36*]. That productivity boom coincided with the adoption of the assembly line and the proliferation of the automobile. Broadcast radio and the electric utility industry saw strong development in the 1920s, and Lindbergh made his famous transatlantic flight, which ushered in the age of aviation. Slow productivity growth in the 1927-1948 period accompanied the Great Depression and World War II. After the war, two factors combined to boost productivity growth: first, output had dropped so far during the Great Depression that simply returning to trend growth required a period of faster economic growth; second, the economy benefited from a wave of innovations, including the building of the interstate highway system, the discovery of transistors, and the emergence of commercial aviation. Between 1948 and 1973, annual labor productivity growth averaged 2.8 percent.

Productivity growth began to slump again in the early 1970s. Higher oil prices undoubtedly played a role in slowing output during the 1970s, but when oil prices returned to pre-1973 levels during the 1980s (in real dollar terms), productivity continued to sag. Other possible explanations include a slower rate of innovations, slower growth of workers' skills, and increased government regulation.

Martin N. Baily has estimated the contributions to nonfarm labor productivity (output per hour) coming from increases in capital per hour worked and labor quality over the period 1948-1995 [*37*]. The "unexplained residual," also termed multifactor productivity (MFP), is defined as the difference between total productivity growth and the contributions from these two factors. Neither capital per hour nor labor quality explains the slowdown in labor productivity in the 1973-1995 period, leaving the explanation or lack thereof to the "unexplained residual" (Table 4). Interestingly, although the contributions from capital per hour did not differ by much between the pre-1973 and post-1973 periods, the contributions from information technology capital rose in the later period, while the contributions from other capital fell.

Figure 8. Labor productivity growth in the nonfarm business sector (5-year average annual growth rate, percent)



Information Technology and the Productivity Growth of the Late 1990s

Numerous studies have attempted to explain the increase in labor productivity from the 1973-95 period to the post-1995 period. The conclusions of Steven Oliner and Daniel Sichel, the 2001 *Economic Report of the President*, and Dale Jorgenson, Mun Ho, and Kevin Stiroh [*38*] were summarized by Baily (Table 5). Although the three studies used slightly different data to support their analyses, there are fundamental similarities in their conclusions. As in Baily's analysis of the earlier time period, information technology was the largest single identifiable factor contributing to labor productivity growth after 1945. The boost to productivity from information technology more than offset the drag on productivity from other capital.

In each of the three studies, the majority of the acceleration in labor productivity growth in the post-1995 period was assigned to the residual (or MFP) effect: 0.8 percent to 0.9 percent of the estimated 1.2-percent and 1.4-percent increases in labor productivity

Table 4. Labor productivity growth in the nonfarm business sector, 1948-1973 and 1973-1995 (average annual percent growth)

Component	1948-1973	1973-1995	Difference
Output per hour	2.9	1.4	-1.5
Contributions from			
Capital per hour	0.8	0.7	-0.1
Information technology	0.1	0.4	0.3
Other	0.7	0.3	-0.4
Labor quality	0.2	0.2	0.0
Residual (MFP)	1.9	0.4	-1.5
R&D	0.2	0.2	0.0

Table 5. Estimated changes in labor productivity growth between 1995-2000 and 1973-1995 (percent)

Component	Oliner and Sichel	2001 Economic Report of the President	Jorgenson, Ho, and Stiroh
Output per hour	1.2	1.4	0.9
Contributions from			
Capital per hour	0.3	0.4	0.5
Information technology	0.6	0.6	0.4
Other	-0.3	-0.2	0.1
Labor quality	0.0	0.0	-0.1
Residual (MFP)	0.8	0.9	0.5
Computer sector	0.2	0.2	0.3
Other	0.3	0.7	0.2

(nonfarm business sector) in the first two studies and 0.5 percent of the estimated 0.9-percent increase in labor productivity (business sector) in the third analysis. In the studies by Oliner and Sichel and Jorgenson, Ho, and Stiroh, more than one-half of the MFP effect was attributed to the computer sector. The 2001 *Economic Report of the President* suggested, however, that most of the increase came from outside the computer sector.

Meyer, Baily, and others see the bunching of productivity-enhancing innovations working in combination with a favorable U.S. economic environment to boost productivity. In Baily's words, "rapid advances in computing power, software and communications capabilities formed a set of powerful complementary innovations." An increasingly deregulated U.S. economy created a highly competitive environment that drove out inefficiencies, displaced low-productivity firms with high-productivity ones, and forced the adoption of new innovations in order to survive. While the new innovations were available globally, the highly competitive environment may explain why U.S. productivity rates benefited more from them than did other world economies. And finally, globalization expanded markets and increased international competition, further raising the productivity of U.S. firms.

More recently, Stiroh has found that the recent productivity revival is broad-based, with nearly two-thirds of the 61 industries in his analysis showing accelerating productivity gains [*39*]. Furthermore, Stiroh found that productivity growth was higher in industries that either produced information technologies or used them intensively. Thus, Stiroh's industry analysis supports the conclusion that information technology capital was a significant contributor to the post-1995 productivity surge.

Future Outlook for Productivity Growth

The issue of productivity growth is very important for the future economic growth of any nation. For the United States this issue has given rise, understandably, to a significant amount of empirical literature that has investigated the determinants of productivity growth in the past and the future. The *AEO2004* projections for productivity growth lie within the range of historical experience and of the future expectations published by experts, as described below.

Most researchers who have studied the issue and prognosticated about the future outlook have an expectation that annual labor productivity growth will be above 2 percent for the next decade or so. Table 6 shows estimates from recent studies of projected growth in labor productivity. The list represents most of the well-known researchers in the productivity field. All the point estimates of future annual labor productivity growth shown in Table 6 are 2.0 percent or higher, and the estimated ranges fall between a low of 1.3 percent and a high of 3.0 percent.

The key question in developing the *AEO2004* reference case forecast was whether the recent surge in productivity growth would continue. The majority view of the productivity experts cited here is that strong growth in labor productivity will continue for several more years. For example, the U.C. Berkeley economist J. Bradford DeLong writes: "Will this new, higher level of productivity growth persist? The answer appears likely to be 'yes.' The most standard of simple applicable growth models . . . predicts that the social return to information technology investment would have to suddenly and discontinuously drop to zero for the upward jump in productivity growth to reverse itself in the near future. More sophisticated models that focus in more detail on the determinants of investment spending or on the sources of increased total factor productivity appear to strengthen, not weaken, forecasts of productivity growth over the next decade" [*40*].

Naysayers about the productivity revival include Steven Roach and Robert Gordon. Roach believes that much of the post-1995 productivity revival is a statistical illusion resulting from the lack of a satisfactory measure of productivity in the white collar services sector. Gordon argues that the role of information technology has been overstated, and that other factors influencing productivity growth—such as the international and domestic economic environment and fiscal and monetary policies—led to the strong

Table 6. Estimates of future steady-state growth in U.S. labor productivity (percent per year)

Source	*Point estimate*	*Range*
Oliner and Sichel (2002)	—	*2.0 to 2.8*
Jorgenson, Ho, and Stiroh (2002)	*2.25*	*1.3 to 3.0*
Congressional Budget Office (2002)	*2.2*	—
2001 Economic Report of the President (2002)	*2.1*	—
Baily (2002)	—	*2.0 to 2.5*
Gordon (2002)	—	*2.0 to 2.2*
Kiley (2001)	—	*2.6 to 3.2*
Martin (2001)	*2.75*	*2.5 to 3.0*
McKinsey (2001)	*2.0*	*1.6 to 2.5*
Roberts (2001, updated)	*2.6*	—
DeLong (2002)	*"like the fast-growing late 1990s"*	

trend in recent years. Regardless of his views about the role of technology in productivity growth, Gordon's expectation is that productivity will soon return to its trend growth rate of 2.25 percent [*41*].

Lower 48 Natural Gas Supply

Production from domestic natural gas resources is projected to increase as demand grows. Much of the increase is expected to be met from unconventional resources, changing the overall mix of domestic natural gas supply. Of the 18.6 trillion cubic feet of lower 48 natural gas production in 2002, 42 percent was from conventional onshore resources, 32 percent was from unconventional resources, and 26 percent was from offshore resources. By 2025, 43 percent of total lower 48 natural gas production (21.3 trillion cubic feet) is projected to be met by unconventional resources (Figure 9).

The volume of estimated technically recoverable resources is sufficient to support increased reliance on unconventional natural gas sources. Lower 48 remaining technically recoverable resources are identified in five categories (Figure 10):

- *Conventional undiscovered nonassociated resources* are unproved resources of natural gas, not in contact with significant quantities of crude oil in a reservoir, that are estimated to exist in fields that have yet to be discovered, based on geologic formations and their propensity to hold economically recoverable natural gas. The estimate of lower 48 technically recoverable undiscovered conventional nonassociated natural gas resources as of January 1, 2002, is 222 trillion cubic feet.
- *Conventional inferred reserves* are gas deposits in known reservoirs that are considered likely to exist on the basis of a field's geology and past production but have not yet been developed. The bulk of the estimated 232 trillion cubic feet of lower 48 inferred reserves is in onshore reservoirs.
- *Unconventional resources* (tight gas, shale gas, and coalbed methane), estimated at 475 trillion cubic feet, make up the largest category of unproved resources.
- *Associated-dissolved resources*, the remaining unproved lower 48 natural gas resource, occur in crude oil reservoirs as free gas (associated) or as gas in solution with crude oil (dissolved). They are estimated at a total of 136 trillion cubic feet.
- *Proved natural gas reserves* are located in known and developed reservoirs with demonstrated production potential. As of January 1, 2002, lower 48 proved natural gas reserves were estimated to be 175 trillion cubic feet.

Just a few years ago, it was believed that natural gas supplies would increase relatively easily in response to an increase in wellhead prices because of the large domestic natural gas resource base. This perception has changed over the past few years. While average natural gas wellhead prices since 2000 have generally been higher than during the 1990s and have led to significant increases in drilling, the higher prices have not resulted in a significant increase in production. With increasing rates of production decline, producers are drilling more and more wells just to maintain current levels of production. A significant increase in conventional natural gas production is no longer expected. Drilling deeper wells in conventional reservoirs is expected to slow the overall decline in conventional onshore nonassociated gas production, and drilling in deeper waters is expected to offset the decline in shallow offshore production. Increasing

Figure 9. Lower 48 natural gas production, 1990-2025 (trillion cubic feet)

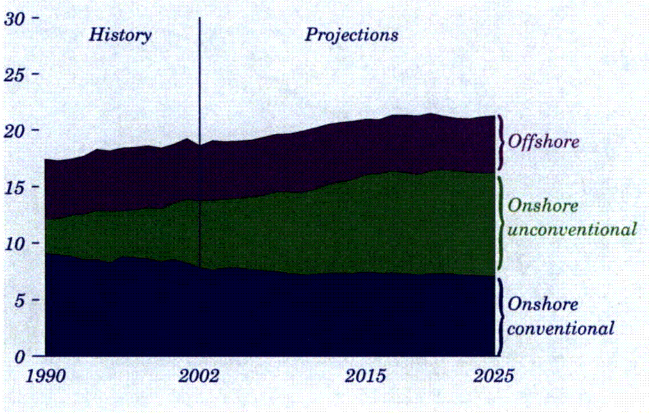
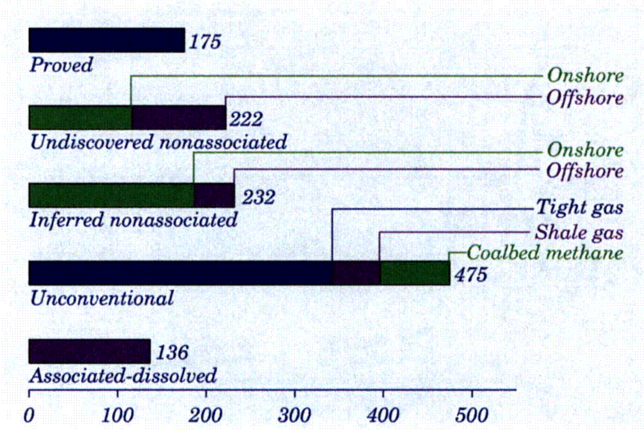


Figure 10. Technically recoverable lower 48 natural gas resources as of January 1, 2002 (trillion cubic feet)



production from unconventional gas plays is drilling and/or technology intensive and is likely to lead to higher wellhead prices.

Conventional Sources

The share of natural gas production from conventional resources is expected to decline over the projection period, from 68 percent in 2002 to 57 percent in 2025. Most of the projected decline is in onshore conventional nonassociated natural gas production, where the majority of exploration and development has occurred historically. Lower 48 offshore natural gas production is expected to remain relatively flat throughout the projection period, as production from fields in the deep waters of the Gulf of Mexico offset the decline in the production in shallow waters.

Onshore

With fewer and smaller new onshore conventional reserve discoveries, emphasis is expected to focus on increasing the expected recovery of currently known fields. Reserve additions from onshore conventional natural gas wells, both exploratory and developmental, are projected to add less than 1 billion cubic feet per well to total reserves in 2025 (Figure 11). The development of deep reservoirs (more than 10,000 feet) in both known fields and new discoveries is projected to play an important role in slowing the decline in the average finding rate for conventional onshore wells. However, drilling to deeper depths increases the average cost of drilling and places upward pressure on prices.

Because larger fields with higher levels of production generally are found first, developed, and replaced with smaller fields, production will tend to decline over time if drilling levels are roughly constant; however, changes in prices influence drilling. Conventional natural gas drilling is expected to increase throughout the projection period, from 6,440 wells in 2002 to 9,140 wells in 2010 and 11,930 wells in 2025 (Figure 12). Less than 10 percent of future natural gas drilling is expected to be exploratory, reflecting the relative maturity of the lower 48 conventional onshore resources. The projected increase in natural gas drilling enables producers essentially to maintain conventional onshore nonassociated production at the current level of approximately 6 trillion cubic feet.

Offshore

Offshore production, primarily in the Gulf of Mexico, is expected to remain a key source of domestic natural gas supply through 2025. Although natural gas production in the shallow waters of the Gulf of Mexico has been declining since 1997, recent developments in deep gas (more than 15,000 feet) in the shallow waters and deepwater (water depth more than 200 meters, or 656 feet) have shown some promise. To offset some of the high costs associated with drilling deep gas wells and deepwater wells, the U.S. Minerals Management Service has offered incentives in the form of royalty relief on qualifying new leases and has proposed additional royalty relief on some existing leases (see “Legislation and Regulations”).

Because the deep waters of the Gulf of Mexico contain primarily oil resources, much of the increase in deepwater gas production is expected to come from associated-dissolved gas. Table 7 shows some of the principal deepwater fields that have recently started production or are expected to start production before 2007. Many of the small fields are being developed as subsea tie-backs to existing infrastructure as a way of making them economically viable. In addition to these deepwater fields, two significant deep gas

Figure 11. Conventional onshore nonassociated natural gas reserve additions per well, 1990-2025 (billion cubic feet)

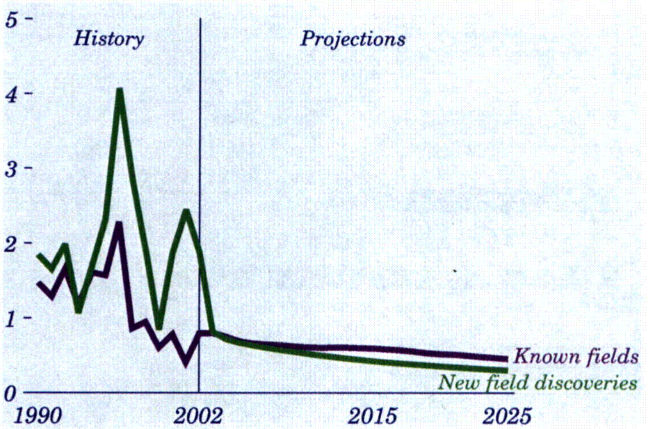
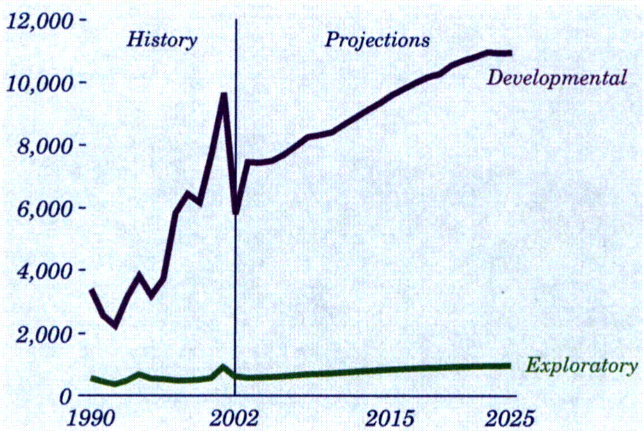


Figure 12. Conventional onshore natural gas wells drilled, 1990-2025 (number of wells)



discoveries—JB Mountain and Mound Pond in shallow waters off the coast of Louisiana—were announced in 2003.

Given the discrete nature of offshore field development, projected offshore natural gas production is expected to be uneven over time. Lower 48 offshore natural gas production is projected to peak in 2010 at 5.4 trillion cubic feet, 11.3 percent higher than in 2002. Associated-dissolved gas, which is primarily in the deep waters of the Gulf of Mexico, is projected to increase by more than 50 percent, from 1.1 trillion cubic feet in 2002 to 1.6 trillion cubic feet in 2010. Projected production of nonasssociated gas in 2010 is about the same as in 2002 at 3.8 trillion cubic feet. In the Gulf of Mexico, shallow gas production is projected to decline at an average annual rate of 0.4 percent, while deepwater gas production is projected to increase at an average annual rate of 4.1 percent between 2002 and 2010 (Figure 13). After 2010, lower 48 offshore natural gas production drops to a low of 4.8 trillion cubic feet, then increases to approximately 5 trillion cubic feet in 2025.

Unconventional Gas

Natural gas extracted from coalbeds (coalbed methane) and from low permeability sandstone and shale formations (tight sands and gas shales) is commonly referred to as unconventional gas. Most of these resources must be subjected to a significant degree of stimulation (e.g., hydraulic fracturing) or other "unconventional" production techniques to attain sufficiently economic levels of production. Unconventional gas has become an increasingly important component of total lower 48 production over the past decade (Figure 14). From 17 percent (3.0 trillion cubic feet) of total production in 1990, the unconventional gas share increased to 32 percent (5.9 trillion cubic feet) in 2002.

Exploration of these abundant (Figure 15) but generally higher cost resources received a boost in the late 1980s and early 1990s with the successful implementation of tax incentives designed to encourage their development. Since then, technologies developed and advanced in pursuit of these resources have contributed to continued growth in production in the absence of the tax incentives. Indeed, increasing production from unconventional gas resources has actually offset a decline in conventional gas production in recent years. By 2025, unconventional gas production is projected to account for 43 percent (9.2 trillion cubic feet) of total lower 48 natural gas production.

Undeveloped Resources

References to undeveloped unconventional resources in *AEO2004* refer to what the United States Geological Survey (USGS) classified as "Continuous-Type (Unconventional) Accumulations" in its 1995 Assessment [*42*]. The resource estimates in that assessment

Table 7. Principal deepwater fields in production or expected to start production by 2007

Field name	Operator	Type	Water depth (feet)	Start Year	Expected peak natural gas production (million cubic feet per day)
Aconcagua	TotalFinaElf	Gas	7,000	2002	80
Aspen	BP	Oil/Gas	3,063	2002	30
Boomvang	Kerr-McGee	Oil/Gas	3,548	2002	200
Camden Hills	TotalFinaElf	Gas	7,210	2002	175
Horn Mountain	BP	Oil/Gas	5,400	2002	68
King Kong	Mariner	Oil/Gas	3,799	2002	150
Nansen	Kerr-McGee	Oil/Gas	3,677	2002	200
Falcon	Pioneer	Gas	3,419	2003	175
Matterhorn	TotalFinaElf	Oil/Gas	3,850	2003	55
Medusa	Murphy	Oil/Gas	2,131	2003	110
Morgus	Shell	Oil/Gas	3,957	2003	55
Nakika Fields	Shell, BP	Oil/Gas	5,700-7,500	2003-2004	325
Front Runner	Pioneer	Oil/Gas	3,329	2004	110
Harrier	Pioneer	Gas	3,400	2004	100
Marco Polo	Anadarko	Oil/Gas	4,286	2004	100
Gunnison	Kerr-McGee	Oil/Gas	3,132	2004	200
Mad Dog	BP	Oil/Gas	4,951	2004	40
Red Hawk	Kerr-McGee	Gas	5,334	2004	150
Llano	Shell	Oil/Gas	2,700	2005	74
Magnolia	ConocoPhilips	Oil/Gas	4,673	2005	150
Entrada	BP	Oil/Gas	4,642	2006	110
Great White	Shell	Oil/Gas	8,000	2006	125
Thunder Horse	BP	Oil/Gas	6,089	2006	55

represent the volume of unproved resources that remain to be added to proved reserves utilizing the technology and development practices existing at the time of the assessment (January 1994). Continuous-type resources are defined to include those "resources that exist as geographically extensive accumulations that generally lack well-defined oil/water or gas/water contacts" [*43*]. This category encompasses "coalbed gas, gas in many of the so-called 'tight sandstone' reservoirs, and auto-sourced oil- and gas-shale reservoirs" [*44*].

Undeveloped resources of unconventional gas are predominantly located in three regions. The bulk of tight sands and coalbed methane (71 percent and 78 percent, respectively) are in the Rocky Mountain region. Sixty-eight percent of undeveloped gas shale resources are in the Northeast region, with most of the remainder in the Southwest region. There are small-to-moderate quantities of tight sands and lesser amounts of gas shales and coalbed methane in the other regions.

Figure 13. Gulf of Mexico natural gas production, 1990-2025 (trillion cubic feet)

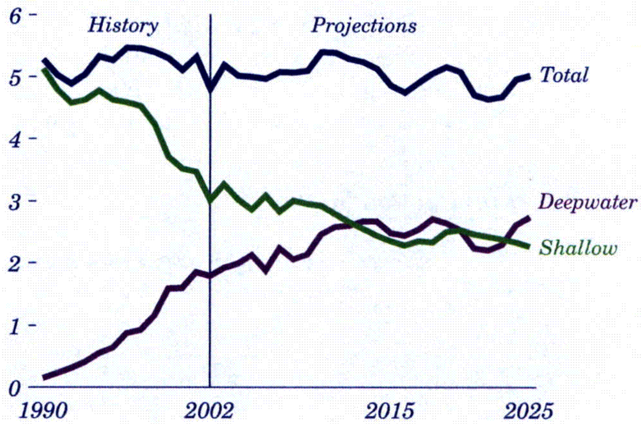
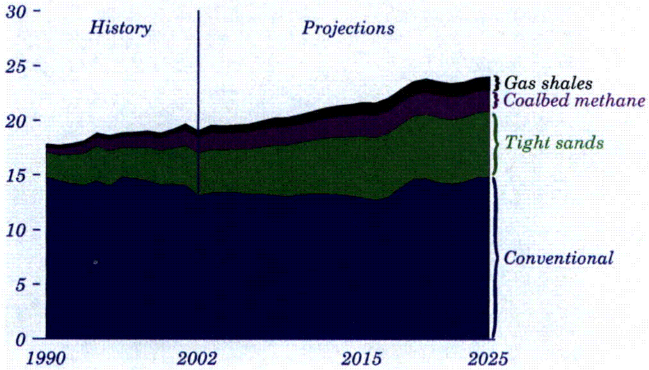


Figure 14. Lower 48 natural gas production by resource type, 1990-2025 (trillion cubic feet)



For *AEO2004*, undeveloped unconventional resources are adjusted to reflect changes indicated by Advanced Resources International (ARI), an independent consultant specializing in unconventional gas. Some plays have been updated to reflect new data, other plays previously lacking data have been assessed as data became available, and new unconventional plays have been identified when appropriate.

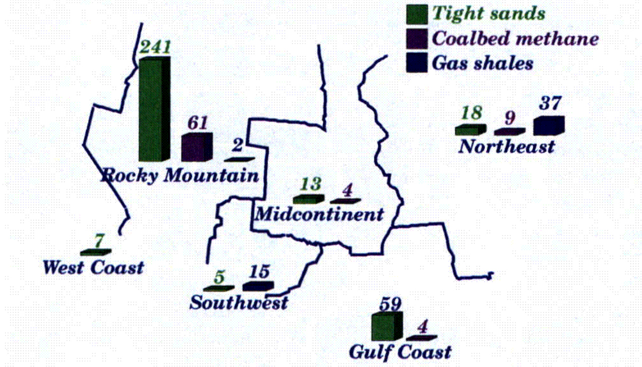
Two examples illustrating the importance of updating are the shale gas (Barnett Shale) in the Fort Worth Basin and coalbed methane in the Powder River Basin. In the 1995 USGS assessment, the Barnett Shale was not assessed due to lack of sufficient data. During the past few years, however, shale gas production from the Fort Worth Basin has been growing at a rapid pace. By obtaining from ARI an interim assessment of the shale gas potential in the basin, EIA was able to project this significant component of current natural gas supply more accurately.

The Powder River Basin was assessed by the USGS in 1995, but the abundant coalbed methane resources were substantially underestimated on the basis of then-available data. Although the USGS has significantly increased its assessment of coalbed methane since 1995, interim consultation with ARI allowed EIA to make this important adjustment years earlier. Several other basins in the Rocky Mountains [*45*] have recently been reassessed by the USGS, but there was insufficient time to reconcile those estimates with the EIA values for comparable areas.

Proved Reserves

Proved reserves of unconventional gas are highest in the Rocky Mountain region for coalbed methane and tight sands and highest in the Northeast for gas shales (Figure 16). Approximately 83 percent (14.6

Figure 15. Unconventional gas undeveloped resources by region as of January 1, 2002 (trillion cubic feet)

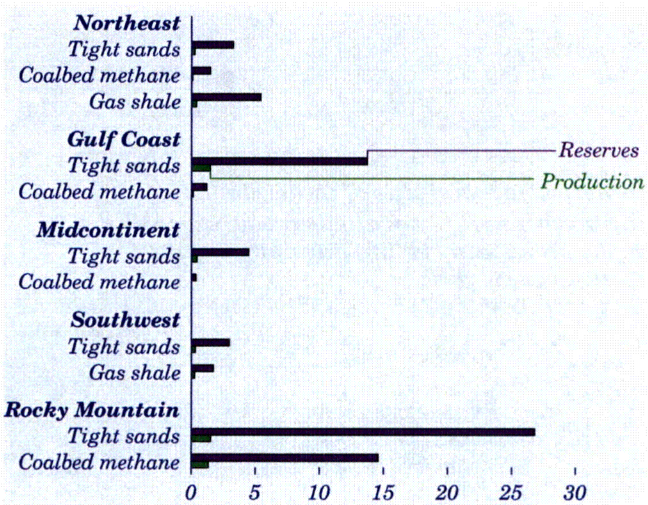


trillion cubic feet) of coalbed methane and 52 percent (26.8 trillion cubic feet) of tight sands proved reserves are located in the Rocky Mountain region. Seventy-six percent (5.4 trillion cubic feet) of gas shales proved reserves are located in the Northeast region, but substantial amounts also exist in the Southwest (1.7 trillion cubic feet). Significant quantities of tight sands proved reserves are located in all the other regions, except for the West Coast. Coalbed methane proved reserves are limited largely to the Northeast (1.5 trillion cubic feet) and the Gulf Coast (1.2 trillion cubic feet), with a small amount (0.3 trillion cubic feet) in the Midcontinent. No significant volume of unconventional gas proved reserves exists in the West Coast region.

Production

Tight Sands. The two regions that are currently the largest producers of gas from tight sands are the Rocky Mountain region and the Gulf Coast region, which account for 39 percent and 37 percent, respectively, of total U.S. tight sands gas production (Table 8). The Rocky Mountain region is projected to experience the most growth in gas production from tight sandstone formations, with 66 percent of total U.S. tight sands gas production expected to originate from this region in 2025. Within the region, tight sands production is projected to increase at the fastest rate (approximately 8 percent per year) in the Wind River basin, with development accelerating in the later years of the forecast. Production from tight sands in the Uinta basin is also expected to grow at a robust rate (about 5 percent per year).

Figure 16. Unconventional gas beginning-of-year proved reserves and production by region, 2002 (trillion cubic feet)



In terms of quantity, the largest contribution from the region will be the Greater Green River basin. *AEO2004* projects the share of total U.S. tight sands gas production sourced from the Green River basin to increase from 15 percent in 2002 to 36 percent by 2025. In the other Rocky Mountain basins, tight sands gas production is projected to rise moderately, except for the Piceance, where production is projected to decline by about 4 percent per year between 2002 and 2025.

Tight sands production from the Gulf Coast region is projected to increase into the middle of the forecast period until primary tight sands plays in the two major basins reach maturity and production begins dropping back toward current levels. Production from tight sandstone formations in other U.S. regions is projected to decline (Midcontinent and Southwest regions) or remain relatively stable (Northeast region).

Coalbed Methane. AEO2004 projects coalbed methane production to remain concentrated largely in the Rocky Mountain region, but the region's share is projected to drop modestly from 88 percent in 2002 to 81 percent by 2025 (Table 9). Within the Rocky Mountain region, growth in coalbed methane production from the prolific Powder River basin and in the Uinta and Raton basins is expected to be offset somewhat by

Table 8. Tight sands gas production by region and basin, 2002-2025 (billion cubic feet)

	Production					
Region/basin	**2002**	**2005**	**2010**	**2015**	**2020**	**2025**
Northeast Region						
Appalachian	232	202	214	243	246	212
Gulf Coast Region						
LA/MS Salt/ Cotton Valley	555	724	991	1,213	1,138	959
Texas Gulf	894	731	811	776	670	589
Total	1,449	1,455	1,802	1,989	1,807	1,548
Midcontinent Region						
Arkoma	149	98	88	92	91	90
Anadarko	259	172	136	99	61	47
Total	408	271	224	190	152	138
Southwest Region						
Permian	285	216	169	163	159	146
Rocky Mountain						
Uinta	91	175	212	255	240	262
Wind River	95	120	194	304	410	588
Denver	109	143	172	201	211	188
Greater Green River	569	657	1,005	1,455	1,792	2,148
Piceance	100	97	78	73	54	37
San Juan	498	607	655	725	758	714
Northern Great Plains	40	33	44	53	61	61
Total	1,502	1,833	2,361	3,066	3,526	3,998
Total	**3,877**	**3,976**	**4,770**	**5,651**	**5,891**	**6,041**

production declines in the relatively mature San Juan basin. Overall growth in the region averages about 1 percent per year.

Elsewhere, significant growth in coalbed methane production is projected for the Northeast region, where the share of total U.S. coalbed methane production increases from 4 percent in 2002 to 8 percent by 2025. Coalbed methane production in the Gulf Coast region is expected to be fairly stable, with declines in the later years of the forecast in the Black Warrior basin offset by increasing production from the Cahaba basin. Although starting from a relatively low level (10 billion cubic feet), coalbed methane production in the Midcontinent region is projected to grow more rapidly than in any other region.

Gas Shales. Natural gas production from tight shale formations occurs predominantly in the Northeast region and the Southwest region (Table 10). Total production from gas shales in the Northeast region is projected to increase at a relatively moderate pace, as production from the Antrim basin remains relatively stable and production in the Appalachian basin grows at about 4 percent per year. In the Southwest region, continued development of gas shales in the Fort Worth-Barnett basin is projected to increase that region's share of total U.S. shale gas production from 39 percent in 2002 to 46 percent by 2025.

Access Restrictions

A current natural gas development issue concerns the ability of producers to access natural gas resources on Federal lands. Most of the unconventional gas resources are in the Rocky Mountains, where they are subject to a variety of access restrictions. In 2002, the Federal Government, under authority of the Energy Policy and Conservation Act (EPCA), conducted an interagency assessment of access restrictions for five major basins in the Rocky Mountains [*46*]. The access assumptions for the Rocky Mountains in *AEO2004* reflect the results of the EPCA assessment.

In *AEO2004*, 7 percent of the undeveloped unconventional gas resources are officially off limits to either drilling or surface occupancy (Table 11). Included in the off-limits category are areas where drilling is precluded by statute (e.g., national parks and wilderness areas) and by administrative decree (e.g., "Wilderness Re-inventoried Areas" and "Roadless Areas"). Also included are those areas of a lease where surface occupancy is prohibited to protect stipulated resources, such as the habitats of endangered species of plants and animals. An additional 26 percent of the resources are judged currently to be developmentally constrained because of the prohibitive effect of compliance with environmental and pipeline regulations created to effect such laws as the National Historic Preservation Act, the National Environmental Policy Act, the Endangered Species Act, the Air Quality Act, and the Clean Water Act.

Approximately 15 percent of the resources are accessible but located in areas where lease stipulations,

Table 9. Coalbed methane production by region and basin, 2002-2025 (billion cubic feet)

	Production					
Region/basin	**2002**	**2005**	**2010**	**2015**	**2020**	**2025**
Northeast Region						
Appalachian	*62*	*97*	*134*	*159*	*165*	*147*
Illinois	*0*	*0*	*0*	*3*	*8*	*11*
Total	*62*	*97*	*134*	*161*	*173*	*158*
Gulf Coast Region						
Black Warrior	*110*	*111*	*115*	*122*	*97*	*79*
Cahaba	*0*	*3*	*10*	*15*	*29*	*30*
Total	*110*	*113*	*125*	*137*	*126*	*109*
Midcontinent Region	*10*	*21*	*33*	*64*	*107*	*114*
Rocky Mountain						
San Juan	*848*	*828*	*784*	*783*	*685*	*588*
Powder River	*325*	*357*	*407*	*531*	*586*	*617*
Uinta	*92*	*89*	*92*	*169*	*230*	*255*
Raton	*54*	*77*	*136*	*151*	*144*	*132*
Other	*1*	*3*	*1*	*0*	*6*	*20*
Total	*1,320*	*1,354*	*1,420*	*1,634*	*1,650*	*1,611*
Total	***1,502***	***1,586***	***1,712***	***1,997***	***2,056***	***1,992***

Table 10. Shale gas production by region and basin, 2002-2025 (billion cubic feet)

	Production					
Region/basin	**2002**	**2005**	**2010**	**2015**	**2020**	**2025**
Northeast Region						
Appalachian	*173*	*221*	*249*	*360*	*429*	*411*
Antrim	*190*	*175*	*173*	*229*	*230*	*201*
Illinois New Albany	*3*	*1*	*1*	*0*	*0*	*0*
Total	*367*	*397*	*423*	*590*	*659*	*612*
Southwest Region						
Fort Worth-Barnett	*233*	*222*	*374*	*434*	*500*	*520*
Total	***600***	***619***	***797***	***1,024***	***1,159***	***1,132***

Table 11. Access status of undeveloped unconventional natural gas resources in the Rocky Mountain region, January 1, 2002 (trillion cubic feet)

Access status	***Unconventional resources***
Officially inaccessible	*23.44*
Inaccessible due to development constraints	*83.71*
Accessible with lease stipulations	*47.51*
Accessible under standard lease terms	*172.92*
Total	***327.58***

which affect accessibility, are set by a Federal land management agency (either the U.S. Bureau of Land Management or the U.S. Forest Service). The remaining 53 percent of undeveloped Rocky Mountain unconventional gas resources are located either on Federal land without lease stipulations or on private land, and are accessible subject to standard lease terms.

The treatment of access restrictions in the *AEO2004* varies by restriction category. Resources located on land that is officially inaccessible are removed from the operative resource base. Resources located in areas that are developmentally constrained because of environmental and pipeline regulations are initially removed from the resource base, then made available gradually over the forecast period to reflect the tendency of technological progress to enhance the ability of producers to overcome difficulties in complying with the restrictions. Resources that are accessible but located in areas that are subject to lease-stipulated access limitations are accounted for by making two adjustments: exploration and development costs are increased to reflect the increased costs that access restrictions generally add to a project; and time is added to the schedule to complete a project to simulate the delay usually incurred as a result of efforts to comply with access restrictions.

Reassessment of Liquefied Natural Gas Supply Potential

Interest in liquefied natural gas (LNG) as a source for fuel supply in the United States has been rekindled and strengthened as a result of sustained high natural gas prices, declining costs throughout the LNG supply chain (production, liquefaction, transportation, and regasification), and recent regulatory changes (see "Legislation and Regulations"). During the winter of 2000-2001—a colder winter than normal—natural gas prices on the domestic spot market climbed above $10.00 per thousand cubic feet, and the average wellhead price increased to $6.82 per thousand cubic feet in January 2001. At that time, plans were announced for the reopening of mothballed LNG terminals in Maryland (Cove Point) and Georgia (Elba Island), and plans for the construction of additional new facilities were being discussed.

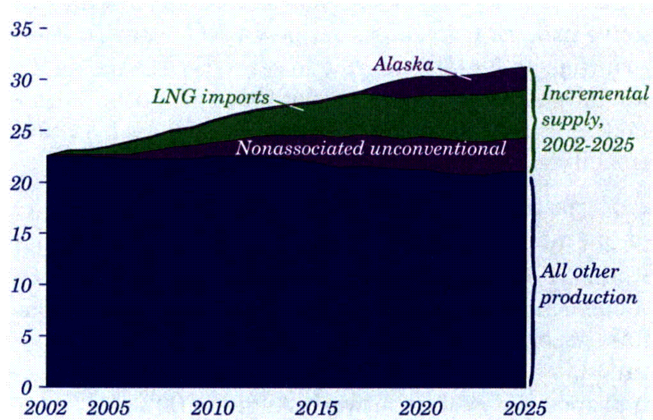
By July 2001, wellhead natural gas prices had dropped below $3.50 per thousand cubic feet, where they remained for most of 2002. Interest persisted in LNG, which generally was thought to be economical in the price range of $3.50 to $4.00 per thousand cubic feet, but momentum slowed as investors waited cautiously to see whether prices would remain below $3.50. In late 2002, average wellhead prices again began to rise, to $3.59 per thousand cubic feet in November and $3.84 in December. They have remained well above $4.00 per thousand cubic feet since then. Average wellhead prices for the first half of 2003 ranged from a low of $4.47 per thousand cubic feet in January to a high of $6.69 in March, contributing to the belief that there has been a fundamental upward shift in natural gas prices.

LNG imports are expected to constitute an increasing proportion of U.S. natural gas supply (Figure 17). Total net imports are projected to supply 21 percent of total U.S. natural gas consumption in 2010 (5.5 trillion cubic feet) and 23 percent in 2025 (7.2 trillion cubic feet), compared with recent historical levels of around 15 percent. Nearly all of the increase in net imports, from 3.5 trillion cubic feet in 2002, is expected to consist of LNG.

LNG imports already have doubled from 2002 to 2003, based on preliminary estimates that show LNG gross imports at 540 billion cubic feet in 2003, compared with 228 billion cubic feet in 2002. Strong growth in LNG is expected to continue throughout the forecast period, with LNG's share of net imports growing from less than 5 percent in 2002 to 39 percent (2.2 trillion cubic feet) in 2010 and 66 percent (4.8 trillion cubic feet) in 2025.

In the *AEO2004* forecast, four new LNG terminals are expected to open on the Atlantic and Gulf Coasts between 2007 and 2010. The first new LNG terminal in more than 20 years is projected to open on the Gulf Coast in 2007. Although the actual sizes of the new plants will vary, for projection purposes a generic size of 1 billion cubic feet per day is used in *AEO2004* for

Figure 17. Major sources of incremental natural gas supply, 2002-2025 (trillion cubic feet)



new facilities on the Gulf Coast and 250 to 500 million cubic feet per day elsewhere. One facility, expected to serve Florida, is planned for construction in the Bahama Islands, with the gas to be transported through an underwater pipeline to Florida.

Existing U.S. LNG plants are expected to be at, or close to, full capacity by 2007, importing 1.4 trillion cubic feet annually, and new plants are projected to import a total of 812 billion cubic feet in 2010. In addition, a new terminal in Baja California, Mexico, is expected to start moving gas into Southern California in 2007, with volumes reaching 180 billion cubic feet by 2008. Additional capacity in Baja California is expected to be added in 2012, increasing annual deliveries into Southern California to 370 billion cubic feet per year from 2014 through 2025. Other new terminals are expected to be constructed in the Mid-Atlantic and New England regions by 2016, and significant additional capacity is expected along the Gulf Coast by 2025, including expansions of existing terminals and construction of new ones. Imports into new Gulf Coast terminals are projected to total nearly 2.5 trillion cubic feet in 2025.

It is considerably more expensive to build LNG regasification plants at new U.S. sites than to expand capacity at existing sites. In addition, LNG delivered to new sites can be expected to have higher production and shipping costs if it is obtained from new, potentially more distant and expensive supply sources. Delays and regulatory costs are also expected to add to the price of gas for new facilities. As a result, "trigger prices" for the construction of new LNG plants are estimated currently at $3.62 to $4.58 per million Btu, compared with less than $2.87 to $3.15 per million Btu for expansion at existing plants.

With changing market conditions, most forecasters now expect LNG to become an increasingly important source of incremental natural gas supply for the United States. As of August 2002, there were 16 active proposals to construct new LNG regasification terminals in North America to serve U.S. markets (or partially serve, as in the case of three proposed terminals in Baja California, Mexico), with total annual capacity slightly over 5 trillion cubic feet.

As of December 1, 2003, there were 32 active proposals for new terminals (Table 12): 21 in the United States, 4 in Baja California, Mexico (to serve both Mexico and U.S. markets), 2 in Mexico, 3 in the Bahamas (to serve U.S. markets), and 2 in Canada (to serve Canada and possibly also U.S. markets). The increase in proposed capacity between August 2002 and October 2003 includes both additional terminals and increases in capacity for many of those previously proposed. Proposed projects active during the summer of 2002 were primarily for terminals with a capacity of 1 billion cubic feet per day or less, whereas 9 of the current proposals are for terminals with a capacity of 1 to 2 billion cubic feet per day. If all the U.S. LNG facilities currently being proposed were completed, they would add more than 15 trillion cubic feet to annual U.S. import capacity. In addition, two proposed terminals in Mexico to serve Southern Mexican markets would have the indirect affect of reducing U.S. natural gas exports to Mexico.

Three proposals to construct terminals in the onshore Gulf of Mexico have been filed with the U.S. Federal Energy Regulatory Commission, and one, Cameron LNG (formerly Hackberry), has received preliminary approval (see "Legislation and Regulations"). Two more proposals for the offshore Gulf of Mexico have been filed with the U.S. Coast Guard. Despite this strong activity, proposals for new capacity involve significant risk and uncertainty, and not all are expected to move forward.

The delivery of new LNG supplies to a new U.S. regasification facility requires the financing, permitting, and construction of at least four expensive infrastructure components: gas production and processing facilities in a source country; an LNG liquefaction plant and export terminal; LNG transport tankers; and the LNG regasification and import terminal in the destination country. Additional pipeline capacity—either to the liquefaction plant or away from the regasification facility—might also be needed. If any aspect of the infrastructure chain is delayed by permitting, financing, or construction problems, the potential profitability of the endeavor could be significantly diminished.

Delays in the eventual commissioning of a new LNG supply chain ending in the United States could occur for a number of reasons:

- Changing circumstances in the U.S. natural gas market
- Changing political conditions or government policies, either in the United States or abroad
- Labor strikes or other local opposition (for example, Bolivia recently decided to end its LNG export program because of political unrest)
- Delays in financing (for example, Peru's Camisea LNG project has been delayed by problems in arranging financing with the Andean Development Corporation)
- International competition for LNG supplies.

Global developments are also contributing to the domestic emphasis on LNG, as new liquefaction facilities proliferate around the world and potential supply sources expand. Until 1995, almost all U.S. LNG imports were from Algeria. More recently, shipments have also been received from Nigeria, the United Arab Emirates, Oman, Qatar, Malaysia, Australia, and Trinidad and Tobago. Additional sources of supply exist throughout the world where liquefaction facilities are either being developed or are in the planning stages.

Current worldwide liquefaction capacity and LNG consumption are roughly equivalent at slightly over 6 trillion cubic feet per year, indicating that supply constraints are contributing to the current underutilization of U.S. regasification capacity. The equivalency of capacity and consumption is changing, however, with an additional annual capacity of 2 trillion cubic feet under construction and scheduled to come on line by 2006 and an additional 8.5 trillion cubic feet of capacity planned to come on line by 2011. Trinidad and Tobago, with current annual capacity of approximately 300 billion cubic feet, has now surpassed Algeria as the primary source of supply for U.S. markets. With an additional 157 billion cubic feet scheduled to come on line by 2006 and 570 billion cubic feet under consideration for development by 2011, Trinidad and Tobago (located in relative proximity to the U.S.) is an important player in the future growth of the U.S. LNG market.

As the global market evolves, LNG is becoming an increasingly important energy source for many countries. A number of European and Asian nations already rely heavily on LNG. Japan, in particular, depends on LNG to meet its power generation needs. As the world market for LNG continues to expand,

Table 12. North American LNG regasification proposals as of December 1, 2003 (million cubic feet per day)

Project	*Owners*	*Location*	*Start year*	*Capacity added*
West Coast				
Terminal GNL Mar Adentro de B.C.	*ChevronTexaco*	*Baja California, Mexico (offshore)*	2007	750
Tijuana Regional Energy Center	*Marathon/Golar LNG/Grupo GGS*	*Baja California, Mexico*	2006	750
Sound Energy Solutions	*Mitsubishi*	*Long Beach, California*	2007	700
Terminal LNG de Baja California	*Shell*	*Baja California, Mexico*	2007	1,000
Energia Costa Azul LNG	*Sempra Energy*	*Baja California, Mexico*	2007	1,000
Crystal	*Crystal Energy*	*Oxnard, California (offshore)*	2006	600
Tractebel Mexico	*Tractebel*	*Lazaro Cardenas, Mexico*	2007	500
Cabrillo Port LNG	*BHP Billiton*	*Oxnard, California (offshore)*	2008	1,500
Florida/Bahamas				
Ocean Express LNG	*AES*	*Ocean Cay, Bahamas*	2006	850
Freeport	*El Paso*	*Freeport Grand Island, Bahamas*	2007	500
Calypso	*Tractebel Bahamas LNG*	*Freeport Grand Cayman, Bahamas*	2007	832
Gulf Coast				
ExxonMobil LNG	*ExxonMobil*	*Quintana Island, Texas*	2007	1,000
Sabine Pass/Cheniere	*Cheniere*	*Sabine Pass, Texas*	2008	2,000
Port Pelican	*ChevronTexaco*	*Louisiana (offshore)*	2007	1,600
Cameron LNG	*Sempra Energy*	*Hackberry, Louisiana*	2007	1,500
Altamira	*Shell*	*Altamira, Mexico*	2004	500
Corpus Christi LNG	*Cheniere Energy*	*Corpus Christi, Texas*	2008	2,000
ExxonMobil/Sabine Pass LNG	*ExxonMobil*	*Sabine Pass, Texas*	2008	1,000
Liberty	*HNG Storage/Conversion Gas*	*Cameron, Louisiana*	2007	3,000
Main Pass Energy Hub	*Freeport-McMoRan Sulphur*	*Gulf of Mexico (offshore)*	2006	1,500
Gulf Landing	*Shell*	*West Cameron, Louisiana (offshore)*	2008-2009	1,000
Vermilion 179	*Conversion Gas Imports*	*Louisiana*	2008	1,000
Mobile Bay LNG	*ExxonMobil*	*Mobile Bay, Alabama*	2008	1,000
Freeport LNG	*Freeport, Cheniere, Contango*	*Freeport, Texas*	2006	1,500
Energy Bridge	*El Paso*	*Floating Dock (offshore)*	2005	500
East Coast				
Canaport	*Irving Oil/Chevron Texaco*	*Canaport, New Brunswick, Canada*	2006	500
Weaver's Cove	*Poten*	*Fall River, Massachusetts*	2007	400
Access Northeast Energy	*Access Northeast Energy*	*Bearhead, Nova Scotia, Canada*	2008	500
Fairwinds LNG	*TransCanada, ConocoPhillips*	*Harpswell, Maine*	2009	500
Providence LNG	*Keyspan, BG LNG Services*	*Providence, Rhode Island*	2005	500
Crown Landing	*BP*	*Logan Township, New Jersey*	2008	1,200
Somerset LNG	*Somerset LNG*	*Somerset, Massachusetts*	2007	430

natural gas is expected to become more of a global commodity, and the world natural gas market is expected to affect the U.S. market [*47*].

An important aspect of globalization is expansion of the LNG spot market. Internationally, most LNG currently is traded under long-term contracts. In recent years, however, the short-term market has played a more significant role, especially in the United States (Figure 18). Most of the LNG imported at the Everett terminal in Massachusetts remains under long-term contract at relatively stable quantities, but short-term deliveries at Lake Charles, Louisiana, have risen and fallen dramatically over the past few years, primarily in response to domestic natural gas prices. In 2002, all cargoes into Lake Charles were delivered under short-term contracts.

Recent developments in Japan and South Korea illustrate the potential impact of global developments on the U.S. LNG market. In Japan, the forced closing of more than a dozen nuclear reactors in 2001 and 2002 because of reporting discrepancies led to greater reliance on fossil fuels for electricity generation. The result was a significant increase in Japan's demand for LNG, so that the majority of world spot cargoes were delivered to the Japanese market. Japan's increased reliance on LNG probably contributed to the reduction in short-term deliveries of LNG to the United States during the winter of 2001-2002, although low natural gas prices also played a role. In South Korea, an unusually cold winter in 2002-2003 led to the diversion of many spot cargoes to that country to meet unusually high demand for heating. The increase in shipments to South Korea may in part explain the low level of U.S. LNG imports during the winter of 2002-2003, when natural gas spot prices were spiking. These examples suggest that an assessment of future U.S. LNG consumption patterns cannot be based solely on the economics of the U.S. natural gas market.

In the United States, an important factor in the future growth of LNG imports is natural gas market prices. The potential impact of U.S. natural gas prices on LNG imports is illustrated by two *AEO2004* sensitivity cases, the rapid and slow technology cases (Figure 19). The rapid and slow technology cases are used to assess the sensitivity of the projections to changes in assumed rates of progress for oil and natural gas supply technologies. To create the cases, reference case parameters for the effects of technological progress on finding rates, drilling activity, lease equipment and operating costs, and success rates for conventional oil and natural gas wells were adjusted by plus or minus 50 percent. Parameters for a number of key exploration and production technologies for unconventional gas were also adjusted by plus or minus 50 percent, and key parameters for Canadian supply were also adjusted to simulate the assumed impacts of rapid and slow oil and gas technology penetration on Canadian supply potential.

In the projections for 2010, natural gas wellhead prices range from $3.25 per thousand cubic feet (2002 dollars) in the rapid technology case to $3.58 in the slow technology case; and in the 2025 projections, the prices range from $3.80 in the rapid technology case to $5.10 in the slow technology case. The volume of LNG imports across the rapid and slow technology cases varies from 1.6 trillion cubic feet to 2.3 trillion cubic feet, respectively, in 2010 and from 3.8 to 5.5 trillion cubic feet in 2025, compared with 0.2 trillion cubic feet in 2002.

Figure 18. U.S. quarterly LNG imports by contract type, 1996-2003 (billion cubic feet)

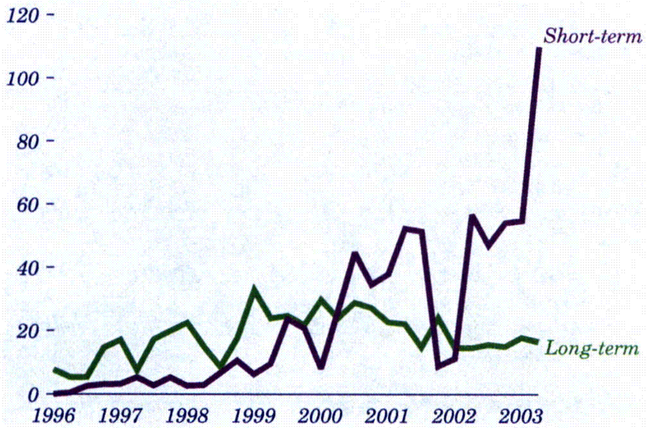
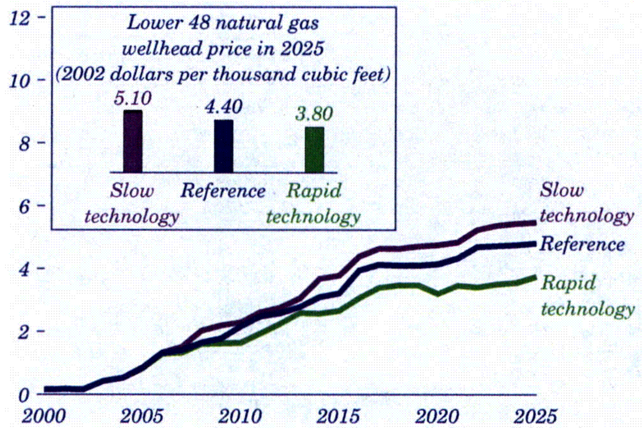


Figure 19. U.S. net imports of LNG, 2000-2025 (trillion cubic feet)



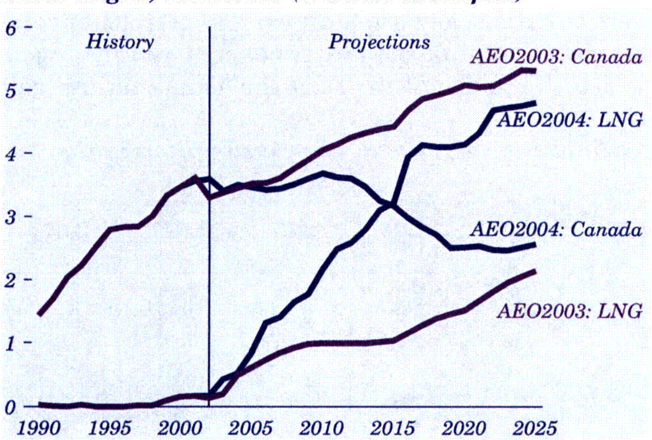
Reassessment of Canadian Natural Gas Supply Potential

Until recently, Canada was expected to remain the primary source of natural gas imports for the United States through 2025, as projected in *AEO2003*; however, the *AEO2004* reference case projects that net imports of LNG will exceed net imports from Canada by 2015 (Figure 20). The primary reason for the change in the *AEO2004* forecast is a significant downward reassessment by the Canadian National Energy Board (NEB) of expected natural gas production in Canada. Both the NEB and the NPC have revised their earlier estimates of total Canadian natural gas production [*48*].

In 1999, NEB estimated total production in Canada in a range of 8.1 to 9.0 trillion cubic feet in 2015 and 7.7 to 9.9 trillion cubic feet in 2025. In contrast, NEB's 2003 estimates show 5.9 to 7.1 trillion cubic feet in 2015 and 4.3 to 6.1 trillion cubic feet in 2025. NPC's 1999 estimate for Canadian production in 2015 was 8.2 trillion cubic feet (no estimate was given for 2025). In 2003, NPC estimated a range of 6.4 to 7.0 trillion cubic feet for 2015 and 5.8 to 6.9 trillion cubic feet for 2025.

Other reasons are declining natural gas production in the province of Alberta, which accounts for more than 75 percent of Canada's natural gas production, and increasing use of natural gas for oil sands production. In its most recent annual reserve report, the Alberta Energy and Utilities Board expects gas production in the province to decline at an average rate of 2 percent per year between 2003 and 2012, while its oil sands production could triple. Because natural gas is one of the fuels used in producing oil sands (see below, "Natural Gas Consumption in Canadian Oil Sands Production"), such a dramatic increase could divert significant amounts of gas from the U.S. import market. Additional factors that could contribute to a decline in Canadian gas exports include higher projections for domestic natural gas demand in Canada and recent disappointments in Canadian drilling results, including smaller discoveries with lower initial production rates and faster decline rates.

Figure 20. U.S. net imports of LNG and Canadian natural gas, 1990-2025 (trillion cubic feet)



Two recent and significant drilling disappointments occurred in northeastern British Columbia's Ladyfern field and the Scotian Shelf Deep Panuke field. Production from the Ladyfern field, heralded as Canada's largest find in 15 years, peaked at 700 million cubic feet per day in 2002 and is declining rapidly. Current production is about 300 million cubic feet per day, and many expect the field to be depleted by the end of 2004. In February 2003, EnCana, initially highly optimistic about the Deep Panuke field, requested that the regulatory approval process for developing the field be placed on hold while it reassesses the economics of development.

The *AEO2004* forecast expects the decline in Canadian imports to be mitigated partially by the construction of a pipeline to move MacKenzie Delta gas into Alberta. Initial flows from the pipeline are expected in 2009, with annual throughput reaching approximately 675 billion cubic feet in 2012 and remaining at that level through 2025.

Natural Gas Consumption in Canadian Oil Sands Production

In recent years, extensive investment has gone into the development of Alberta's oil sands. In 2002, Canada's crude bitumen production from oil sands averaged 790,000 barrels per day, while conventional crude output was 2,140,000 barrels per day (including natural gas liquids). Natural gas is used both to extract the bitumen from the sand and to convert the bitumen into syncrude. Currently, oil sands operations consume approximately 330 billion cubic feet per year of natural gas.

Canadian oil producers have announced a number of new oil sands projects and expansions to existing oil sands facilities. The question has arisen as to whether these existing and future facilities will raise Canada's gas consumption by a significant amount, thereby reducing the amount of Canada gas production, which is available for export to the United States. This discussion will briefly examine this issue.

Most of the existing and proposed oil sands projects are located in the east-central portion of Alberta and are dispersed along a roughly north-south axis of about 200 miles in length. The Canadian oil sands consist of a mixture of sand, bitumen, and water. Based on existing facilities, and project announcements for expansions and new oil sands production facilities, EIA projects total oil sands bitumen production to be 1.7 and 3.3 million barrels per day in 2010 and 2025, respectively (Table 13). In 2010, about 52 percent of the bitumen is projected to be surface mined, and the remaining 48 percent is projected to be produced through in situ production [*49*]. In 2025, approximately 57 percent of the oil sands bitumen is projected to be surface mined, and 43 percent is projected to be produced through the in-situ production method.

To produce synthetic crude oil, the bitumen can be either partly or totally petroleum coked or hydrocracked. Petroleum coking requires less process energy than hydrocracking and does not require a hydrogen feedstock, but 100 barrels of bitumen yields only 79 barrels of syncrude. Hydrocracking, on the other hand, requires both more process energy and a hydrogen feedstock, but 100 barrels of bitumen produces about 106 barrels of syncrude.

There are three potential fuels that can be used either exclusively or in part to produce oil sands syncrude, namely, natural gas, produced bitumen, or petroleum coke, the latter of which is a process byproduct. Depending upon an oil sands facility's design flexibility, the syncrude producer can change the slate of inputs, such as natural gas, and the slate of outputs (e.g., syncrude, petroleum coke) so as to maximize the profit margin associated with the production and upgrading of bitumen into syncrude, based on the cost/price of both the inputs and outputs. Consequently, the consumption of natural gas in these upgrading facilities is expected to change over time as relative prices change. Moreover, the input/output flexibility of any particular bitumen upgrading facility can be enhanced in the future, if prices warrant. Consequently, if natural gas prices were sufficiently high and oil prices sufficiently low, syncrude producers could theoretically eliminate natural gas consumption entirely through the exclusive use of bitumen and petroleum coke to provide the energy and feedstocks to produce and upgrade the bitumen.

Carbon dioxide emissions might also play a role in determining the proportions of natural gas, bitumen, and petroleum coke used for oil sands production and processing. On December 17, 2002, Canada ratified the Kyoto Protocol, which obligates it to reduce carbon dioxide emissions to 6 percent below their 1990 level. Because petroleum coke and bitumen release more carbon dioxide when burned than natural gas does, Canada's Kyoto Protocol obligation could limit the use of petroleum coke and bitumen in the processing of bitumen from Canadian oil sands.

If natural gas were to be used exclusively to produce and convert bitumen into syncrude, then the following volumes of natural gas would be consumed to perform each of the following processes:

- Surface mine 1 barrel of bitumen—approximately 131 cubic feet
- In situ production of 1 barrel of bitumen—1,000 to 1500 cubic feet
- Petroleum coking 1 barrel of bitumen—approximately 168 cubic feet
- Hydrocracking 1 barrel of bitumen—approximately 490 cubic feet.

The natural gas consumption estimates presented in Table 13 assume that natural gas is the *only* energy and feedstock source for the production and upgrading of bitumen into syncrude. Table 13 assumes that the in situ production of bitumen requires 1,250 cubic feet of natural gas per barrel of bitumen. The first estimate (Case I) assumes that the bitumen is exclusively petroleum coked to create syncrude, while the second (Case II) assumes that the bitumen is exclusively hydrocracked. Of course, if oil sands producers were to extensively use bitumen and petroleum coke to provide most of the process energy and hydrogen feedstock requirements, then the actual natural gas

Table 13. Projected Canadian tar sands oil supply and potential range of natural gas consumption in the AEO2004 reference case, 2002-2025

Projection	*2002*	*2005*	*2010*	*2015*	*2020*	*2025*
Tar sands oil supply (million barrels per day)						
Mined bitumen	*0.43*	*0.56*	*0.87*	*1.64*	*1.82*	*1.87*
In situ bitumen	*0.36*	*0.44*	*0.82*	*1.33*	*1.38*	*1.41*
Total unconventional	*0.79*	*1.00*	*1.69*	*2.97*	*3.20*	*3.28*
Potential natural gas consumption (billion cubic feet per year)						
Case I: Petroleum coking of bitumen into syncrude	*NA*	*289*	*519*	*867*	*913*	*934*
Case II: Hydrocracking of bitumen into syncrude	*NA*	*406*	*718*	*1,216*	*1,289*	*1,319*

consumed in future years would be considerably less, potentially as low as zero.

In conclusion, given the potential fuel flexibility of oil sands production facilities, the question of whether Canadian oil sands production will consume significant volumes of natural gas is not easily answered. The answer to this question will depend not only on the relative prices of syncrude and natural gas, but also on the degree to which oil sands producers build fuel-flexible facilities. Consequently, the actual outcome could be as high as 1.3 trillion cubic feet per year or as low as zero.

Natural Gas Consumption in the Industrial Sector

Natural gas consumption in the U.S. industrial sector increased by 1.6 percent per year on average from 1990 to 2000, fell sharply in 2001, and continued to decline in 2002. During the 1990s, the industrial sector accounted for slightly less than 37 percent of total U.S. natural gas consumption, peaking in 1997 at 8.7 quadrillion Btu or 37.5 percent of the total. In the *AEO2004* reference case, industrial natural gas use is projected to return to a path of steady increase after 2003, averaging 1.5-percent annual growth from 2002 to 2025 (Figure 21). Total natural gas consumption for industrial uses is projected to reach 10.6 quadrillion Btu in 2025—3.1 quadrillion Btu higher than in 2002—based on projected growth in industrial output and modestly increasing natural gas prices over the forecast period.

Within the industrial sector, natural gas use for combined heat and power (CHP) applications is projected to increase by 2.6 percent per year, for feedstocks by 0.8 percent per year, and for boiler fuel and direct uses by 1.4 percent per year from 2002 to 2025 (Figure 22). With total industrial output (value of shipments) increasing by 2.6 percent annually over the same period, the natural gas intensity of industrial output in 2025 is projected to be 21 percent lower than in 2002.

As a result of the economic recession that began in 2001 and the rise in natural gas prices since 2000, some industry observers have concluded that segments of the U.S. industrial sector have permanently reduced output through closures of manufacturing plants, and that the result will be a permanent reduction in demand for natural gas. Others note that similar industrial reactions to sharp increases in gas prices and to recessions are not unprecedented, and that the recent drop in demand is likely to be temporary [*50*] once industrial production growth resumes. A history of the recent relationship between industrial production and natural gas consumption is shown in Figure 23. In the absence of severe, multi-year recessions in the industrial sector and sustained higher prices for natural gas, it is reasonable to expect industrial output and natural gas consumption to increase in the future.

AEO2004 projects little or no growth in industrial demand for coal, and most of the projected increase in demand for petroleum products is for asphalt and petroleum byproducts. Natural gas remains the fuel of choice in the industrial sector and will continue to fire most CHP applications. In the *AEO2004* reference case, industrial natural gas prices are projected to rise by 1.4 percent per year on average, to $5.00 per million Btu in 2025—60 cents lower in constant 2002 dollars than the 2003 price (Figure 24).

Some portions of the industrial sector, however, are especially sensitive to natural gas prices—particularly those that use natural gas as a feedstock, such

Figure 21. Industrial natural gas consumption, history and projections, 1990-2025 (quadrillion Btu)

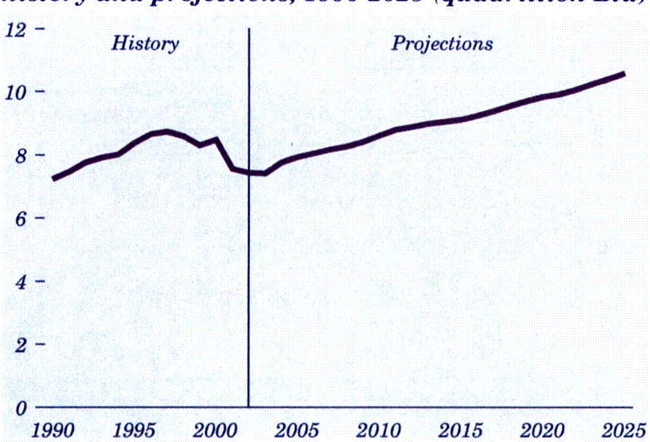
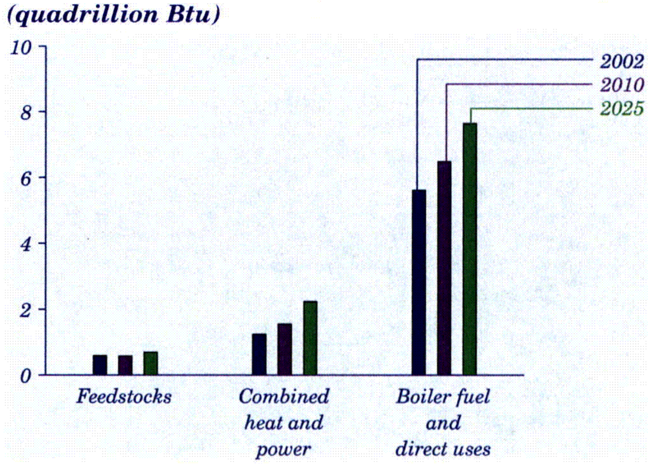


Figure 22. Components of industrial natural gas consumption, 2002, 2010, and 2025 (quadrillion Btu)



as nitrogenous fertilizer production, organic chemical production, and petrochemical production. For example, 0.7 quadrillion Btu of natural gas was used for feedstocks in the chemical industry in 1998 [*51*], accounting for about 10 percent of total natural gas consumption in the manufacturing sector. Petroleum-based products, however, were the largest source of industrial feedstock (for organic chemicals, plastics, synthetic rubber, and petrochemicals), amounting to 3.1 quadrillion Btu, more than four times the quantity of natural gas used as a feedstock in 1998.

One sector particularly sensitive to higher natural gas prices is the nitrogenous fertilizer industry. Natural gas costs account for 70 to 80 percent of the cash cost of fertilizer: production of a ton of ammonia uses 33.5 million Btu of natural gas [*52*]. At the average industrial natural gas price during the 1990s, the embodied cost of energy per ton of ammonia equates to about $120. At the estimated average industrial natural gas price in 2003 ($5.60 per million Btu), the embodied cost of energy is $188 per ton—a 57-percent increase. This significant increase in cost, if passed through completely, would amount to only 9.9 cents per bushel of corn, or 4 percent of the total average price of $2.35 per bushel in 2002 [*53*]. Large percentage increases in costs for ammonia production do not, therefore, necessarily result in proportional increases in the price of agricultural products.

Higher production costs tend to be passed through quickly to the price of ammonia [*54*], although the amount of the pass-through can be reduced by competition from imports. Imports of ammonia historically have accounted for about 20 percent of U.S. demand. Their impact on reducing the amount of pass-through costs can, however, lag over time.

The demand for natural gas as a feedstock to produce ammonia is determined largely by the quantity of ammonia produced, because petroleum-based fuels are not generally a viable economic alternative [*55*]. In 1998, the nitrogenous fertilizer industry consumed 338 trillion Btu of natural gas as a feedstock [*56*]. An additional 234 trillion Btu was consumed for process heating. In principle, the portion of the industry's natural gas consumption used for process heating could be switched to another fuel; however, in 1994 (the most recently available data for fuel switching), the nitrogenous fertilizer industry reported that only 3.1 trillion Btu (1 percent) of its natural gas use was switchable [*57*].

For at least two decades, the nitrogenous fertilizer industry in the United States has been consolidating [*58*]. From 89 plants with an average annual capacity of 171,000 metric tons in 1970, the number of plants fell sharply after 1980, and the average capacity of the remaining plants more than doubled. In 2002 there were only 37 plants operating, with an average capacity of 451,000 metric tons. Total industry capacity in 2002, at 16.7 million metric tons, was only slightly higher than in 1970 (15.2 million metric tons).

The consolidation, or even permanent closure, of nitrogenous fertilizer plants has no meaningful impact on U.S. natural gas markets, because the plants account for only a small portion of total U.S. gas consumption (0.5 quadrillion Btu out of 21.1 quadrillion Btu total in 1998). In addition, permanent closure of fertilizer plants in response to a temporary increase in natural gas prices is unlikely. For example, several producers temporarily idled their plants in the first quarter of 2002, but most of the idled capacity was back on line by the fourth quarter of the year [*59*]. Also, the largest U.S. producer of

Figure 23. Industrial natural gas consumption and output, 1978-2002 (index, 2002 = 1.0)

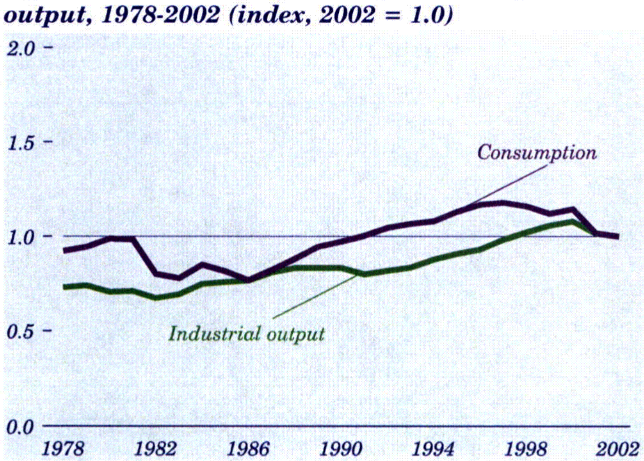
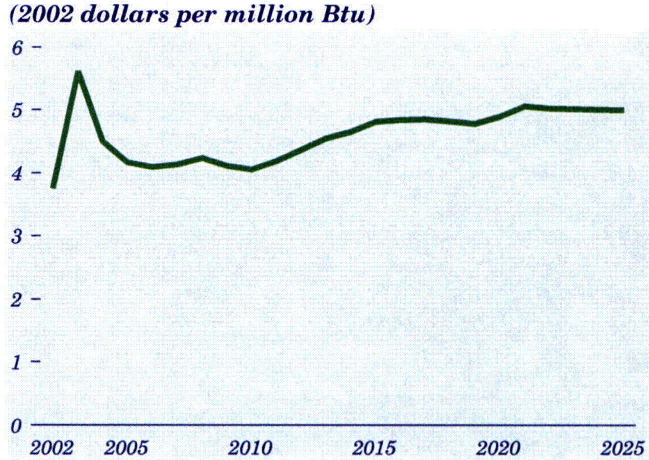


Figure 24. Industrial natural gas prices, 2002-2025 (2002 dollars per million Btu)



nitrogenous fertilizer (Farmland Industries, an agricultural cooperative), which declared bankruptcy in early 2002 [*60*], continued to operate most of its plants.

In the *AEO2004* reference case, industrial sector output is projected to grow by 2.6 percent annually from 2002 to 2025, the same growth rate experienced in the 1990s. The bulk chemical industry is projected to grow by 1.6 percent annually, slightly below its 1.8-percent growth rate during the 1990s. Agriculture is projected to grow by 1.2 percent annually, leading to a projected 0.9-percent annual growth rate for agricultural chemical production, of which nitrogenous fertilizer is a part [*61*]. In 2025, the value of agricultural chemical shipments is projected to be $24 billion, approximately equal to their 1997 value (Figure 25).

Figure 25. Agricultural chemicals value of shipments, history and projections, 1990-2025 (billion 2002 dollars)

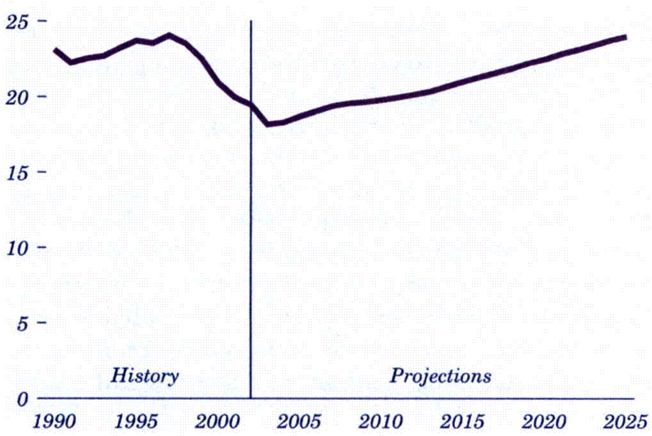
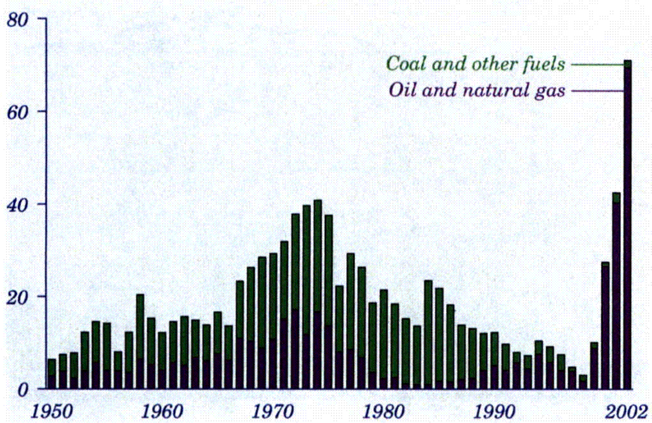


Figure 26. Annual additions to electricity generation capacity by fuel, 1950-2002 (gigawatts)



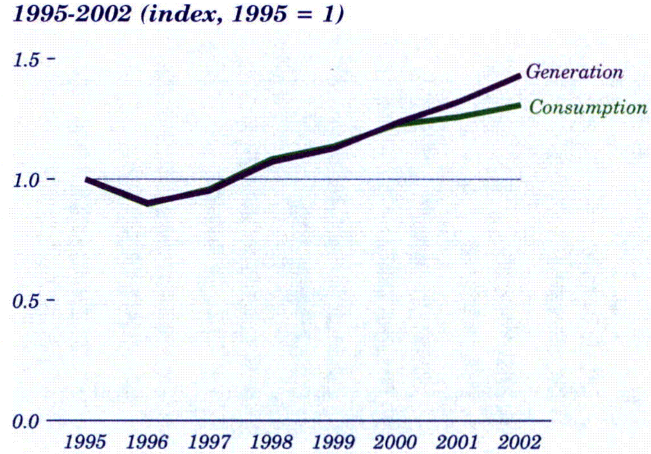
Natural Gas Consumption for Electric Power Generation

Data from EIA's Form EIA-860 survey, "Annual Electric Generator Report," show a dramatic increase in additions to U.S. electricity generation capacity over the past 3 years. In 2000, 2001, and 2002 more than 141 gigawatts of new generating capacity was constructed—far more than in any previous 3-year period. Virtually all of that new capacity uses natural gas as the primary fuel for electricity generation (Figure 26).

Given the recent pace of capacity additions, it is not surprising that the amount of electricity produced from natural gas has increased substantially; however, natural gas consumption in the electric power sector has not increased as rapidly, because the efficiency of gas-fired generation has improved significantly (Figure 27). From 1995 to 2002, natural-gas-fired generation in the power sector increased by 43 percent, but natural gas consumption increased by only 31 percent. Notably, the gap between growth in natural-gas-fired generation and natural gas consumption by power producers began to appear in 2000, when the first wave (27 gigawatts) of the recent surge in capacity expansion occurred.

The role of natural gas in the electric power sector is expected to continue growing for the foreseeable future. At the same time, the disparity between increases in gas-fired generation and in the amount of natural gas consumed by power producers is also expected to continue growing. In addition to the amount of new gas-fired generating capacity added, other factors that will affect the amount of natural gas used to generate electricity over the coming decades include: the rate of growth in electricity sales;

Figure 27. Natural gas consumption and gas-fired electricity generation in the electric power sector, 1995-2002 (index, 1995 = 1)



the efficiencies of new gas-fired plants relative to those of older plants; and the price of natural gas relative to the prices of other fuels, particularly coal.

Relative to the amount of generating capacity operating in 1999, additions over the 2000-2002 period amounted to an increase of 18 percent. Over the same period, electricity sales grew by only 5 percent. Consequently, many of the plants added in recent years are unlikely to be used at full capacity in the early years of their operation. Moreover, an additional 45 gigawatts of new capacity is expected to be added in 2003, all but 2 gigawatts of which will use natural gas. With growth in electricity sales expected to continue at a much more modest pace, the recent disparity between generating capacity growth and sales growth is expected to widen in the near term, and it could be many years before much of the newly added capacity is used intensively.

Where new natural gas plants are used, their generation will often displace generation that would have come from older, less efficient oil- and gas-fired generators. The natural-gas-fired plants that have been added in recent years are much more efficient than older plants. For example, new combined-cycle plants have operating efficiencies between 45 and 50 percent, whereas the efficiencies of older steam plants generally are 33 percent or less. Accordingly, a new plant could generate the same amount of electricity as an older plant while consuming 27 percent less natural gas, or could use the same amount of gas as an older plant while generating 36 percent more electricity [*62*]. The "efficiency gap" between old and new natural-gas-fired power plants is expected to lead power companies to retire many of their older plants, because it will no longer be economical to maintain them. The newer plants, using substantially less fuel, will provide the power that the older plants were generating.

In the *AEO2004* reference case forecast, natural gas consumption in the electric power sector is projected to continue to increase; however, the gap between the growth in natural gas generation and natural gas consumption in the power sector is also projected to widen (Figure 28). In 2025, the amount of electricity generated from natural gas is projected to be 166 percent greater than it was in 1995, but the amount of natural gas consumed for electricity production is projected to increase by only 98 percent. Over the same period, the average efficiency of all generators using natural gas is projected to increase from 33 percent to 45 percent.

Finally, in the later years of the forecast, rising natural gas prices are expected to make new coal-fired capacity economically competitive. When new coal-fired generating plants are added, they will be less expensive to operate than gas-fired plants, including those currently coming into service, and they are expected to be used for baseload generation, meeting customer needs around the clock. The capacity factor for all oil- and gas-fired capacity is projected to decline initially (Figure 29) because of the surge of capacity additions in 2002 and 2003, then rise to about 28 percent in 2018, and then decline as new coal-fired plants come on line. In the *AEO2004* forecast, the end result is that natural gas consumption in the electric power sector is projected to continue growing more slowly than either additions of gas-fired capacity or generation using natural gas.

Figure 28. Natural gas consumption and gas-fired electricity generation in the electric power sector, 1995-2025 (index, 1995 = 1)

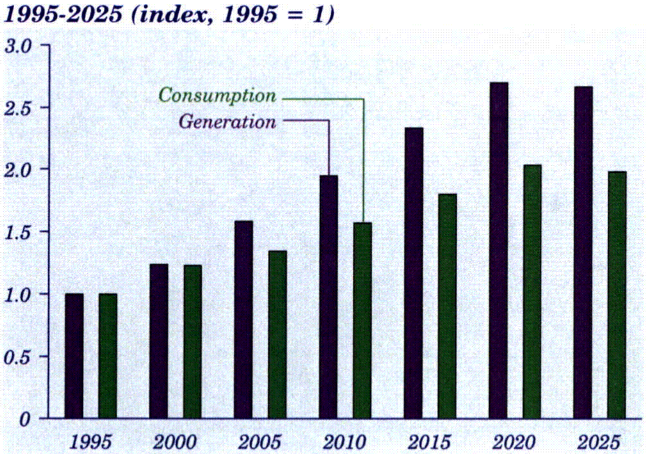
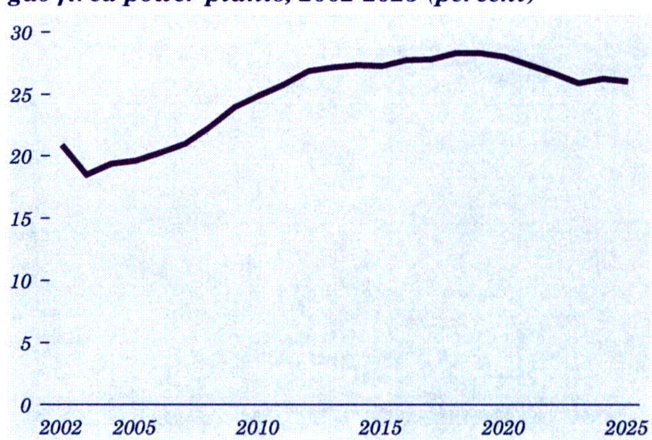


Figure 29. Average capacity factor for oil- and gas-fired power plants, 2002-2025 (percent)



Natural Gas Markets: Comparison of *AEO2004* and National Petroleum Council Projections

The National Petroleum Council (NPC) recently released the first volume of a report describing two possible projections for U.S. natural gas market conditions through 2025 [*63*]. The NPC's Reactive Path and Balanced Future scenarios are compared here with the *AEO2004* reference case. Unlike the *AEO2004* reference case, which assumes the continuation of current laws, policies, regulations, technology trends, and productivity trends through 2025, the two NPC scenarios assume the adoption of new policies, which "move beyond the status quo." Of the two NPC scenarios, the design of the Reactive Path is closer to that of the *AEO2004* reference case than is the design of the Balanced Future scenario.

This discussion focuses on a "global" comparison of the NPC and *AEO2004* projections and assumptions, because the two reports categorize and aggregate energy market data differently. Although the NPC report and *AEO2004* begin from similar estimates of total end-use gas consumption in 2002 (20.5 and 20.8 trillion cubic feet, respectively), the NPC study shows 0.9 trillion cubic feet more gas consumption in the industrial sector and 1.1 trillion cubic feet less gas consumption in the electric power sector in 2002. This accounting difference can be attributed in part to the fact that EIA has revised its data collection and reporting systems for industrial electricity generation, or CHP. In addition, new industrial CHP is reported by the NPC in the electric power sector, whereas historical CHP consumption is counted in the industrial sector. These accounting complications preclude direct comparison of the *AEO2004* and NPC projections for industrial and electric power sector natural gas consumption. Table 14 provides an overview of the *AEO2004* and NPC 2002 data and projections for 2010 and 2025.

The primary similarities between *AEO2004* and the NPC projections include:

- The residential and commercial natural gas consumption projections are almost identical.
- The *AEO2004* gas consumption growth rate associated with electric power generation falls between the growth rates projected in the two NPC scenarios when the accounting is adjusted to be the same for *AEO2004* and the NPC study [*64*].
- The relative proportions of domestic gas production and imports are similar in the *AEO2004* and NPC projections.
- Both *AEO2004* and the NPC projections expect gas imports from Canada to peak in 2009-2010 and decline thereafter.
- Imports of LNG are expected to increase throughout the forecasts, so that by 2025 overseas LNG is the primary source of U.S. natural gas imports.
- Projected volumes of offshore gas production are similar in the two reports.
- Relative to nonassociated conventional gas, unconventional gas is projected to be the least expensive incremental source of lower 48 onshore gas supply.

The primary differences between the *AEO2004* and NPC projection scenarios include:

- The NPC projections expect lower growth in industrial output and a decline in industrial natural gas consumption, leading to lower overall consumption growth than in *AEO2004*.
- The NPC estimate of the cost of developing and producing lower 48 natural gas resources is higher than those in *AEO2004*. As a result, NPC projects higher wellhead prices and less onshore natural gas production.
- The *AEO2004* reference case projects increasing onshore gas production, whereas the NPC scenarios project constant or declining onshore production. This difference can be attributed largely to the *AEO2004* and NPC projections for onshore nonassociated conventional gas production, which is projected to be 5.9 trillion cubic feet in 2025 in the *AEO2004* reference case, compared with 4.2 and 4.1 trillion cubic feet in the NPC Reactive Path and Balanced Future scenarios, respectively.
- The *AEO2004* reference case projects a steady decline in lower 48 onshore associated-dissolved gas production, to 1.2 trillion cubic feet in 2025. Both of the NPC scenarios project a slight decline through 2005, followed by a slight rebound that results in a 2025 projection for lower 48 onshore conventional associated-dissolved gas production that is almost identical to the 2002 level.
- The NPC projects a wide potential range of future gas prices, with Henry Hub spot prices spanning approximately $3.00 to $7.00 per million Btu (2002 dollars) in 2025. *AEO2004* projects 2025 wellhead prices at $4.40 per thousand cubic feet, equivalent to $4.28 per million Btu (2002 dollars) [*65*].

Forecast Assumptions

Both the NPC Reactive Path scenario and the *AEO2004* reference case assume that U.S. GDP will grow by 3 percent per year through 2025. For U.S. electricity generation, *AEO2004* projects 1.8-percent average annual growth from 2002 through 2025, while the NPC Reactive Path and Balanced Future scenarios project average annual growth of 2.1 percent and 2.0 percent, respectively. *AEO2004* projects 2.6-percent annual growth in industrial output, compared with 1.1 percent in the NPC scenarios.

AEO2004 and the NPC scenarios expect different future oil prices. Both the NPC scenarios assume that U.S. refiner crude oil acquisition prices will decline to $18 per barrel in 2005 (2002 dollars) and continue at that level through 2025. *AEO2004* assumes that the refiner acquisition price for imported crude oil will decline to $23.30 per barrel in 2005 and increase slowly to $27.00 per barrel in 2025 (2002 dollars).

The NPC Reactive Path scenario differs from *AEO2004* in projecting the size and composition of the undiscovered lower 48 natural gas resource base (Figure 30). Generally, *AEO2004* assumes a larger resource (1,065 trillion cubic feet) than the Reactive Path and Balanced Future scenarios (770 and 874 trillion cubic feet, respectively) [*66*]. *AEO2004* assumes more onshore conventional resources (392 trillion cubic feet) than the Reactive Path and Balanced Future scenarios (289 and 297 trillion cubic feet) and more unconventional gas resources (475 trillion cubic feet) than the Reactive Path and Balanced Future scenarios (216 and 234 trillion cubic feet). The Reactive Path and Balanced Future scenarios assume more undiscovered offshore gas resources (265 and 343 trillion cubic feet) than *AEO2004* (197 trillion cubic feet). Accordingly, *AEO2004* projects proportionately more onshore gas production at market-clearing prices than do the NPC scenarios.

Table 14. Overview of U.S. natural gas consumption and supply projections, 2002, 2010, and 2025 (trillion cubic feet)

Projection	2002 AEO2004	2002 Reactive Path	2002 Balanced Future	2010 AEO2004	2010 Reactive Path	2010 Balanced Future	2025 AEO2004	2025 Reactive Path	2025 Balanced Future
Consumption									
Residential	4.92	4.79	4.79	5.53	5.48	5.24	6.09	6.17	5.82
Commercial	3.12	3.11	3.11	3.48	3.50	3.49	4.04	4.09	4.18
Subtotal	**8.04**	**7.91**	**7.91**	**9.01**	**8.97**	**8.73**	**10.13**	**10.26**	**10.00**
Industrial	7.23	8.15	8.15	8.39	7.03	7.41	10.29	7.10	7.38
Electric power	5.55	4.45	4.45	6.66	6.67	6.15	8.39	8.18	7.24
Subtotal	**12.77**	**12.59**	**12.59**	**15.05**	**13.70**	**13.56**	**18.68**	**15.28**	**14.62**
Transportation	0.01	—	—	0.06	—	—	0.11	—	—
Total end use	**20.83**	**20.50**	**20.50**	**24.11**	**22.68**	**22.29**	**28.92**	**25.54**	**24.62**
Pipeline fuel	0.63	0.73	0.73	0.67	0.81	0.78	0.84	0.83	0.77
Lease and plant fuel	1.32	1.20	1.20	1.36	1.25	1.25	1.65	1.25	1.24
Total consumption	**22.78**	**22.43**	**22.43**	**26.15**	**24.73**	**24.32**	**31.41**	**27.62**	**26.62**
Supply									
Production									
Total lower 48	**18.62**	**18.09**	**18.09**	**19.90**	**19.04**	**19.00**	**21.29**	**18.89**	**18.90**
Onshore	13.76	13.00	13.00	14.48	13.34	13.53	16.26	13.74	13.00
Associated-dissolved gas	1.60	1.48	1.48	1.41	1.32	1.32	1.17	1.49	1.45
Nonassociated gas	6.23	6.04	6.04	5.80	5.57	5.55	5.93	4.23	4.13
Unconventional gas	5.93	5.34	5.34	7.28	6.31	6.53	9.17	7.91	7.30
Offshore	4.86	5.09	5.09	5.42	5.69	5.47	5.03	5.15	5.90
Alaska	**0.43**	**0.46**	**0.46**	**0.60**	**0.46**	**0.46**	**2.71**	**2.00**	**1.93**
Total production	**19.05**	**18.54**	**18.54**	**20.50**	**19.50**	**19.45**	**23.99**	**20.90**	**20.83**
Net imports									
Canada	3.59	3.60	3.60	3.68	3.50	3.25	2.56	2.70	1.29
Mexico	-0.26	-0.21	-0.21	-0.34	-0.30	-0.30	-0.12	-0.26	-0.26
LNG	0.17	0.23	0.23	2.16	1.99	2.06	4.80	3.88	4.77
Total net imports	**3.49**	**3.61**	**3.61**	**5.50**	**5.19**	**5.01**	**7.24**	**6.31**	**5.80**
Net storage and LNG withdrawals	—	0.45	0.45	—	0.02	-0.01	—	-0.03	-0.05
Supplemental fuels and ethane	0.08	0.09	0.09	0.10	0.27	0.15	0.10	0.43	0.20
Balance item	0.16	-0.26	-0.26	0.06	-0.25	-0.29	0.09	0.01	-0.17
Total U.S. gas supply	**22.78**	**22.43**	**22.43**	**26.15**	**24.73**	**24.32**	**31.41**	**27.62**	**26.62**

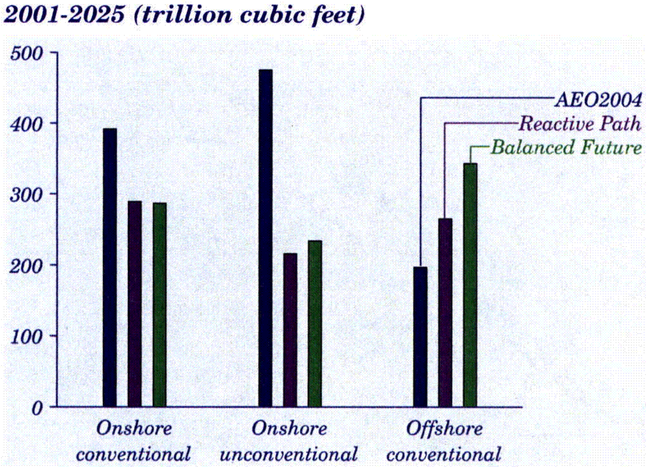
The *AEO2004* and NPC gas resource assumptions differ most significantly with respect to the additional gas resources expected to be discovered in existing onshore conventional oil and gas fields (identified as "field appreciation," "reserve growth," and "inferred resources"). The *AEO2004* assumption is based on USGS resource estimates, which result in an inferred onshore conventional gas resource base of 292 trillion cubic feet. The NPC scenarios are based on a different methodology, which results in 164 trillion cubic feet of inferred resources. Because inferred gas resources are the least expensive incremental source of domestic natural gas supply, the difference in assumptions is responsible in part for the different projections of onshore conventional gas production.

Consumption

The *AEO2004* and NPC projections differ with respect to future levels of natural gas consumption but largely agree on the mix of future supplies. In 2025, *AEO2004* projects total U.S. gas consumption of 31.4 trillion cubic feet, compared with 27.6 trillion cubic feet in the Reactive Path scenario and 26.6 trillion cubic feet in the Balanced Future scenario. Total U.S. consumption of natural gas includes pipeline fuel and production area lease and plant fuel, which is natural gas consumed in production and transportation to end-use markets.

In 2025, the projections for total end-use gas consumption (excluding pipeline, lease, and plant fuel) are 28.9 trillion cubic feet in *AEO2004*, 25.5 trillion cubic feet in the Reactive Path, and 24.6 trillion cubic feet in the Balanced Future scenario (Figure 31). In the *AEO2004* reference case, end-use gas consumption is projected to grow by 1.4 percent per year from 2002 to 2025, compared with 1.0 percent in the Reactive Path and 0.8 percent in the Balanced Future scenario. The differences between the *AEO2004* reference case and the NPC scenarios result largely from different projections for industrial sector natural gas consumption, primarily as a result of the NPC's lower projected growth rate for industrial production.

Figure 30. Lower 48 technically recoverable and accessible unproven natural gas resources, 2001-2025 (trillion cubic feet)



Although NPC and *AEO2004* employ different accounting methods for the treatment of CHP in the industrial sector, one method for comparing the NPC and *AEO2004* industrial and electric power gas consumption projections is to account for the *AEO2004* CHP projection results in the same manner as the NPC scenarios, namely, by allocating incremental CHP gas consumption after 2001 to the electric power sector (Table 15). Based on this reallocation, it is clear that the large difference between the *AEO2004* and NPC end-use gas consumption projections is attributable primarily to significantly different expectations for growth in industrial natural gas consumption. In *AEO2004*, adjusted industrial gas consumption grows by 1.1 percent per year throughout the forecast, whereas the Reactive Path and Balanced Future scenarios project declines of 0.6 percent and 0.4 percent per year, respectively.

In *AEO2004*, natural gas consumption for electric power generation (adjusted for CHP) grows by 2.3 percent per year, which is between the Reactive Path and Balanced Future projections of 2.7 percent and

Figure 31. Total U.S. end-use natural gas consumption, 2001-2025 (trillion cubic feet)

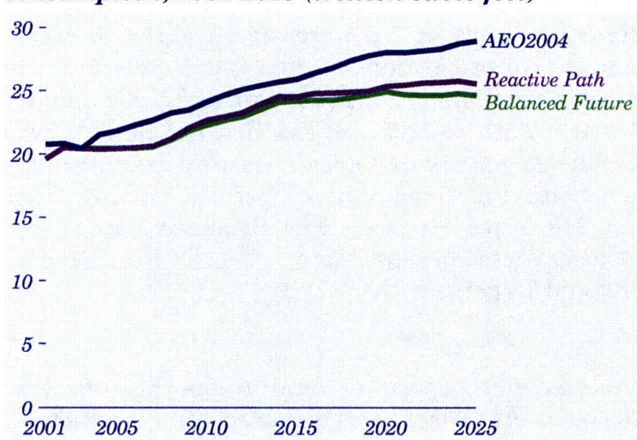


Table 15. Growth rates for natural gas consumption in the industrial and electric power sectors, 2002-2025 (percent per year)

	AEO2004	AEO2004 with CHP adjustment	Reactive Path	Balanced Future
Industrial	1.5	1.1	-0.6	-0.4
Electric Power	1.8	2.3	2.7	2.1

2.1 percent per year, respectively. For residential and commercial end-use consumption, the *AEO2004* and NPC projections are virtually identical throughout the forecast.

In 2025, Henry Hub spot prices for natural gas are projected to be between $5 and $7 (2002 dollars) per million Btu in the Reactive Path scenario and between $3 and $5 per million Btu in the Balanced Future scenario, while end-use natural gas consumption in 2025 is 0.9 trillion cubic feet lower in the Balanced Future than in the Reactive Path scenario. The Balanced Future scenario projects less natural gas consumption despite significantly lower prices, because it assumes that future gas-consuming equipment (including gas-fired generating capacity) will have more flexibility to use other fuels and will be more fuel-efficient than assumed in the Reactive Path scenario.

Supply

In both the NPC study and *AEO2004*, domestic natural gas consumption is satisfied through both domestic gas production and net gas imports [*67*]. In all three scenarios, net imports are projected to grow at a faster rate than end-use gas consumption. *AEO2004* projects average growth in net imports of 3.2 percent per year between 2002 and 2025; the Reactive Path and Balanced Future scenarios project average growth in net imports of 2.5 and 2.1 percent per year, respectively [*68*].

Although the *AEO2004* and NPC end-use gas consumption levels in 2025 are significantly different, the relative proportions of domestic supply and net imports are similar. For 2025, both *AEO2004* and the Reactive Path scenario project that net imports will provide 23 percent of domestic natural gas consumption, with the remaining 77 percent coming from domestic supply sources. The Balanced Future scenario projects corresponding proportions of 22 percent and 78 percent.

Imports and Exports

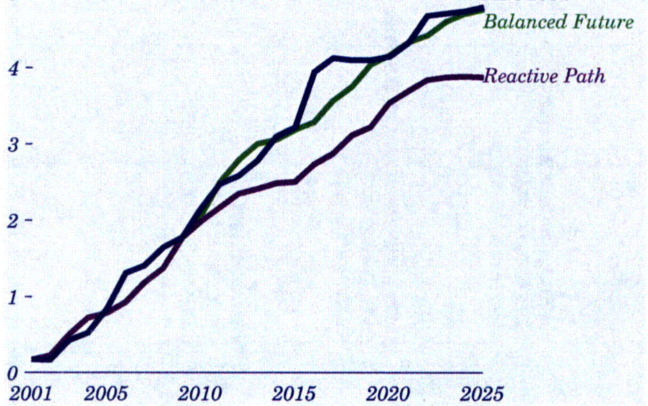
Projected net imports of natural gas (pipeline and LNG) in *AEO2004* are higher than in either of the NPC scenarios. The NPC developed detailed cost estimates for liquefaction, shipping, and regasification facilities and used those estimates to develop exogenous LNG scenario projections. The Balanced Future scenario assumes a more favorable LNG import policy than in the Reactive Path scenario. In the Balanced Future, net LNG imports are projected at 4.8 trillion cubic feet in 2025, compared with 3.9 trillion cubic feet in the Reactive Path scenario (Figure 32). *AEO2004* projects LNG imports on the basis of a comparison between LNG delivery costs and projected natural gas prices. *AEO2004* projects 4.8 trillion cubic feet of net LNG imports in 2025. Although the *AEO2004* projection for net LNG imports in 2025 is almost identical to that in the Balanced Future scenario, in terms of percentage of total net imports, the 66-percent share projected for LNG imports in 2025 in *AEO2004* is closer to the 62-percent share in the Reactive Path than to the 82-percent share in the Balanced Future scenario.

Canada is the other major source of U.S. natural gas imports. In 2025, imports from Canada are projected to make up 35, 43, and 22 percent of total U.S. net imports in the *AEO2004* reference case, NPC Reactive Path, and NPC Balanced Future scenario, respectively. In all the projections, net imports from Canada are projected to peak around 2009 and decline thereafter (Figure 33). *AEO2004* projects 2.6 trillion cubic feet of net imports from Canada in 2025, compared with 2.7 and 1.3 trillion cubic feet in the Reactive Path and Balanced Future scenarios, respectively. Thus, in the NPC study, higher LNG imports are offset by lower imports from Canada. Both *AEO2004* and the NPC scenarios project negligible quantities of net gas exports from the United States to Mexico in 2025, at 0.1 and 0.3 trillion cubic feet, respectively.

Domestic Production

In both the NPC and *AEO2004* projections, natural gas imports increase more rapidly than consumption; thus, all three scenarios project slower growth in U.S. gas production than in consumption. The *AEO2004* reference case projects 1.0-percent average annual growth in domestic natural gas production from 2002 to 2025, compared with 0.5 percent per year in the two NPC scenarios. The projections for total U.S.

Figure 32. Net imports of liquefied natural gas, 2001-2025 (trillion cubic feet)



natural gas production in 2025 are 24.0, 20.9, and 20.8 trillion cubic feet in the *AEO2004* reference case and the Reactive Path and Balanced Future scenarios, respectively (Figure 34). Periods of more rapid increases in U.S. natural gas production are projected for 2018-2020 in *AEO2004* and 2013-2015 in the NPC scenarios, resulting from the advent of North Slope Alaska gas pipeline operations.

The NPC Reactive Path and Balanced Future scenarios both assume that the Alaska gas pipeline will begin operation in 2013 with an initial capacity of 4 billion cubic feet per day. *AEO2004* projects that the pipeline will begin operation in 2018 with a capacity of 3.9 billion cubic feet per day of dry gas, followed in 2023 by a 0.9 billion cubic foot expansion, for a total dry gas throughput capacity in 2025 of 4.8 billion cubic feet per day.

AEO2004 projects total lower 48 production of 21.3 trillion cubic feet of natural gas in 2025, compared with 18.9 trillion cubic feet in the Reactive Path scenario and scenarios—only slightly higher than current production levels. *AEO2004* projects offshore gas production similar to that in the NPC scenarios, but higher onshore gas production. Onshore gas production in *AEO2004* is projected to be 76 percent of total lower 48 production in 2025, compared with 73 percent in the Reactive Path scenario and 69 percent in the Balanced Future scenario. As a result, *AEO2004* projects 16.3 trillion cubic feet of lower 48 onshore gas production in 2025, compared with 13.7 and 13.0 trillion cubic feet in the Reactive Path and Balanced Future scenarios, respectively.

In all three scenarios, lower 48 offshore production fluctuates because sufficient natural gas reserves must be discovered in an area to justify the construction of offshore platforms and pipelines. *AEO2004* projects average offshore gas production of 5.0 trillion cubic feet per year from 2002 through 2025, compared with an average of 5.4 trillion cubic feet per year in the two NPC scenarios.

The projections for cumulative lower 48 natural gas production from 2002 through 2025 are summarized in Table 16. *AEO2004* projects 489 trillion cubic feet of production from the lower 48 gas resource base, proportionately more from onshore (75 percent) than offshore (25 percent). The Reactive Path and Balanced Future projections are similarly apportioned: 72 and 71 percent onshore and the remaining 28 and 29 percent offshore, respectively.

The NPC Balanced Future scenario assumes increased access to Federal offshore areas and onshore lands, while the Reactive Path does not. Federal offshore access adds 79 trillion cubic feet to the offshore technically recoverable and accessible resource base, and greater Federal lands access adds 35 trillion cubic feet to the onshore technically recoverable and accessible gas resource base (see Figure 30) [*69*]. The Balanced Future scenario projects 0.8 trillion cubic feet more cumulative offshore gas production than in the Reactive Path scenario but produces considerably less of the total accessible offshore resource base (Table 17).

Figure 33. Net imports of natural gas from Canada, 2001-2025 (trillion cubic feet)

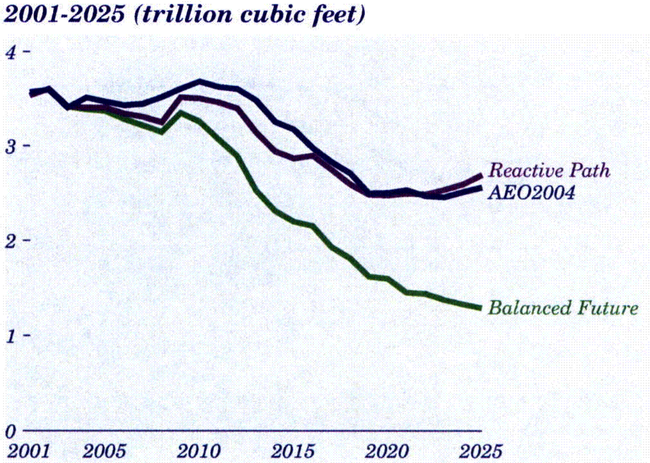


Figure 34. Total U.S. domestic natural gas production, 2001-2025 (trillion cubic feet)

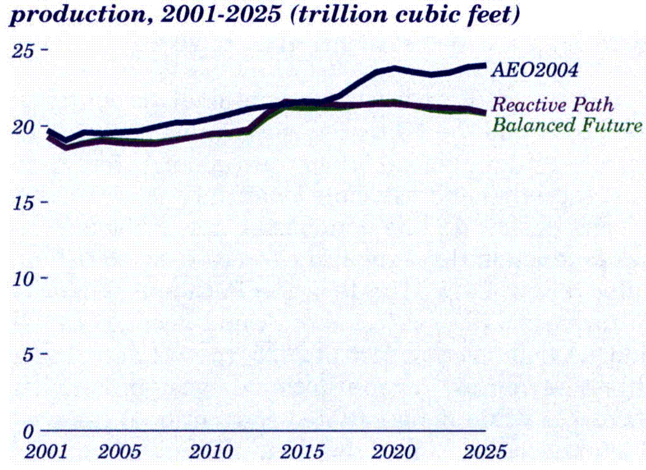


Table 16. Lower 48 cumulative natural gas production, 2002-2025 (trillion cubic feet and percent of total)

	Onshore	Offshore	Total
AEO2004	*367.8 (75%)*	*120.9 (25%)*	***488.7***
Reactive Path	*327.8 (72%)*	*129.2 (28%)*	***457.0***
Balanced Future	*326.0 (71%)*	*130.0 (29%)*	***456.0***

In the Balanced Future scenario, considerably more gas is produced from regions of the offshore Atlantic and Pacific that are currently not accessible. In 2025, the incremental Atlantic and Pacific offshore gas production is projected to be just over 752 billion cubic feet. Most of the incremental offshore gas production that results from increased Federal access occurs in the offshore Atlantic, where gas production is projected to reach 608 billion cubic feet in 2025. The impact of greater Federal access is not apparent until after 2010, because considerable delays are expected to be encountered in leasing, seismic exploration, drilling, and development.

AEO2004 assumes a much larger volume of onshore gas resources, both conventional and unconventional, than do the NPC scenarios (see Figure 30). Also, *AEO2004* and the NPC scenarios project similar levels of offshore gas production, even though *AEO2004* projects considerably more total production than in the NPC scenarios. As a consequence, most of the difference between the *AEO2004* and NPC gas production projections is attributable to their different projections for onshore natural gas production.

The *AEO2004* projection for unconventional natural gas production is consistently higher than the NPC projections [*70*]. In 2025, *AEO2004* projects 9.2 trillion cubic feet of unconventional gas production, compared with the Reactive Path and Balanced Future projections of 7.9 and 7.3 trillion cubic feet (Figure 35). Although the NPC scenario projections for unconventional gas production are quite different in 2025, they are almost identical up to 2020.

For lower 48 onshore conventional production, *AEO2004* and the NPC scenarios again show considerable differences in their projections for both nonassociated and associated natural gas. *AEO2004* projects a slow decline in nonassociated conventional gas production throughout the forecast, to 5.9 trillion cubic feet in 2025. The Reactive Path and Balanced Future scenarios project more rapid declines to 4.2 and 4.1 trillion cubic feet in 2025, respectively. In all three scenarios, unconventional gas production increases while nonassociated conventional gas production does not, indicating that unconventional gas is the least expensive incremental source of lower 48 onshore natural gas production.

Table 17. Portion of the lower 48 natural gas resource base produced, 2002-2025 (percent of technically recoverable and accessible resources)

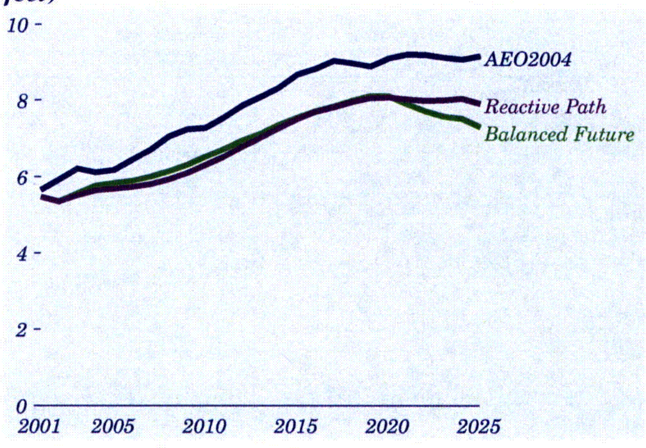
	Onshore	Offshore	Total
AEO2004	*42.4*	*61.4*	***45.9***
Reactive Path	*60.8*	*50.5*	***57.5***
Balanced Future	*56.8*	*38.8*	***50.2***

Lower 48 onshore production of associated-dissolved conventional gas declines throughout the *AEO2004* projection, to 1.2 trillion cubic feet in 2025. In the two NPC scenarios, associated-dissolved conventional gas production declines until 2005, then rises from 1.3 trillion cubic feet in 2005 to 1.5 trillion cubic feet in 2025. Associated-dissolved gas production depends directly on crude oil production, and all three scenarios project declining onshore production of crude oil throughout the forecast period. The NPC scenarios, however, project a slower decline than in the *AEO2004* reference case. In addition, the NPC scenarios project more natural gas production per barrel of oil produced in 2025 than does *AEO2004*, which, in combination with NPC's higher projections for oil production, results in the only instance of a higher projection for a component of domestic natural gas supply in 2025 in the NPC forecasts than in *AEO2004*.

Nuclear Power Plant Construction Costs

With the improved performance of the 104 operating U.S. nuclear power plants, increases in fossil fuel prices, and concerns about global warming, interest in building new nuclear power plants has increased. Because no nuclear plants have been ordered in the United States in nearly three decades, the costs of a new plant are uncertain. To assess the economics of building new nuclear power plants, EIA conducted a series of workshops and seminars focusing on key factors that affect the economics of nuclear power—primarily, the cost of building power plants and the financial risks of constructing and operating them.

Figure 35. Lower 48 onshore unconventional natural gas production, 2001-2025 (trillion cubic feet)



History of Nuclear Power Construction Costs

As was typically the case with fossil-fuel-fired power plants, many of the first-generation U.S. reactors were constructed on a fixed price, turnkey basis. Under this type of contractual arrangement, the vendor assumed all the risk associated with cost overruns and scheduling delays. In total, about 12 units were ordered on a turnkey basis in the early to mid-1960s. Although the costs of the reactors were never made public, one study estimated that the vendors lost more than $1 billion [*71*]. As a result, they eventually stopped offering turnkey contracts to build nuclear power plants and instead went to cost-based contracts.

Factors affecting the costs of non-turnkey U.S. reactors have been the subject of a number of analyses. An EIA analysis found that realized real overnight costs grew from about $1,500 per kilowatt for units beginning construction in the 1960s to about $4,000 per kilowatt for units beginning construction in the early to mid-1970s (all costs in 2002 dollars, except where noted). Lead times also increased, from about 8 years to more than 10 years. Much of the growth in overnight costs and lead times was unforeseen by those preparing the estimates, and overruns in real overnight costs and lead times ranged from 70 to 250 percent [*72*].

Because of severe data limitations and the inherent difficulty in measuring regulatory impacts, there is only qualitative agreement that the following factors caused the growth in nuclear plant costs and lead times [*73*]:

- Increased regulatory requirements that caused design changes (backfits) for plants under construction
- Licensing problems
- Problems in managing "mega projects"
- Misestimation of cost savings (economies of scale) for larger plants
- Misestimation of the need for the capacity.

Historically, the deployment of nuclear plants abroad lagged behind that in the United States. Thus, there was a tendency for utilities in Europe and Asia to learn from the U.S. experience. Now, just the opposite is occurring—the next generation of U.S. nuclear power plants will benefit from foreign learning. Accordingly, EIA's present cost estimates used realized costs of nuclear power plants in Asia as a starting point.

Building New Nuclear Plants in the United States

One of the major uncertainties in building new nuclear power plants involves the regulatory and licensing process. Regulatory actions were one of the factors that contributed to the cost growth in the 1970s and 1980s, and as a result there were significant efforts to reform the process. In the late 1980s, the U.S. Nuclear Regulatory Commission (NRC) modified backfit regulations to make it more difficult to order changes in a plant's design during construction. Additionally, with the passage of the Energy Policy Act of 1992, the licensing process was also changed substantially. Before 1992, a utility needed one license to begin construction and another to begin commercial operation. Public hearings were a prerequisite for both licenses, and in some cases they proved to be very contentious. Now, as long as a firm follows all the agreed-upon procedures, tests, and inspections, separate hearings are not required. The 1992 legislation also allowed for the pre-approval of various designs; as a result, many technical engineering issues can be settled before the licensing process begins.

Beginning in the mid-1990s, the nuclear industry began to design new Generation III (or III+) reactors. In general, the new designs represent incremental improvements over the current generation of light-water reactors. They are simpler and include more "passive" safety features. As discussed below, these design changes have cost implications.

The vendors of two Generation III reactors—the Advanced Boiling Water Reactor (ABWR) and an Advanced Pressurized Water Reactor (the AP1000)—have provided estimates of construction costs. GE's estimate for the ABWR ranges from $1,400 to $1,600 per kilowatt (2000 dollars) for a large, single-unit plant (1,350 megawatts or more). British Nuclear Fuels Limited (BNFL), the manufacture of the AP1000, has estimated that construction costs for the first two-unit 1,100-megawatt reactors will range from $1,210 to $1,365 per kilowatt (2000 dollars). GE's estimate assumes that the government would pay for 50 percent of the first-of-a-kind engineering costs, and BNFL's estimate assumes that the government (or someone other than the purchaser of the plant) would pay for all the first-of-a-kind costs. BNFL also assumes that, because of learning, a third two-unit plant could be built for about $1,040 per kilowatt (2000 dollars) [*74*].

A state-owned Canadian firm, Atomic Energy Canada Limited (AECL), has also stated its intention to market an advanced CANDU reactor, the ACR-700, in the United States. The ACR-700, a design that uses heavy water to moderate the reaction, is substantially different from the AP1000 and ABWR [*75*]. One major advantage of CANDU reactors, which have been built worldwide [*76*], is the ability to refuel the unit while it is operating. Light-water reactors must be taken out of service before they can be refueled. On the other hand, the use of heavy water raises nuclear proliferation issues. The total cost of building "third of a kind" twin-unit plants has been estimated by AECL at about $1,100 to $1,200 per kilowatt.

All the above estimates are much lower than the capital costs that have been realized in the past for nuclear power plants built in the United States and abroad [*77*]. As noted above, the average construction cost of U.S. units that entered commercial operation in the 1980s was about $4,000 per kilowatt. On average, light-water and CANDU reactors have been built in the Far East and elsewhere abroad at costs that are in the low $2,000s per kilowatt. The AP1000 has never been built anywhere in the world. If the vendors are able to achieve their projected costs, their plants are likely to be competitive with other generating options. The key question is whether cost reductions of the magnitude projected by the vendors are achievable.

There is reason to believe that new reactors will be less costly to build than those currently in operation in the United States. Over the past 30 years, there have been technological advances in construction techniques that would reduce costs. In addition, the simplified, standardized, and pre-approved designs clearly result in cost savings. The newer plants have fewer components and therefore would be less costly. At least in the United States, only a few previously built plants were based on standardized designs, and in most cases construction began before the unit was totally designed. The construction of customized units, with the design work being done during the plant's construction, is clearly expensive. Because the designs of advanced reactors are (or will be) pre-approved by the NRC, much of the design work will be done before their construction begins, and this will lower costs. Regulatory changes will also lower regulatory costs and risk.

Although it is reasonable to expect lower construction costs for the new reactors, EIA and other organizations have questioned the size of the cost reductions [*78*]. This is particularly true of the vendors' estimates relative to recently realized costs in Asia.

All the cost estimates from nuclear vendors assume savings from building large multi-unit plants. The estimates for the AP1000 and CANDU reactors assume two unit sites, and those for the ABWR deal with a 1,350- to 1,500-megawatt reactor. As discussed below, the size of these projects has financial implications that cannot be overlooked. Moreover, there is some evidence that cost overruns for earlier U.S. reactors resulted from misestimation of the savings from building large or multi-unit plants.

There are four major parties (and numerous secondary ones) involved in the construction of a nuclear power plant: a firm that manages the construction of the plant, a firm that supplies engineering and architectural support, a firm that supplies the reactor or Nuclear Steam Supply System, and the firm that purchases the unit. All incur costs, and it is important that all their costs be included in the estimate. It is possible that some reported estimates might deal only with the costs to two or three of the parties; in such cases, the estimates would not be inclusive.

Results of EIA-Sponsored Workshops and Seminars and Derivation of EIA Estimates

In addition to sponsoring several workshops and seminars on the subject of nuclear construction costs, EIA also commissioned a series of reviews of the vendor estimates. All the reviewers generally found that the estimates included the costs to the four parties involved with the construction of a nuclear power plant, but they also found that the estimates were not sufficiently detailed to permit verification of their accuracy. Indeed, the only way to verify the estimates would be to reproduce them—an effort that is prohibitively expensive.

EIA's reviewers were forced to use their subjective judgment, and there were differing opinions about the estimates. The reviewers and workshop participants from the nuclear industry think that the cost reductions are achievable, making arguments similar to the ones presented above. One reviewer who is an outside observer of the industry, one workshop participant who is a financial analyst, and some outside researchers were more skeptical. For example, in a recent study from the Massachusetts Institute of Technology (MIT), researchers used $2,000 per kilowatt as a "base case" and employed a 25-percent cost reduction as "unproven but plausible."

The procedure used to derive nuclear construction cost estimates for *AEO2004* is as follows. For non-nuclear technologies, EIA uses cost estimates consistent with realized outcomes for the construction of new generating capacity in the United States. However, because no reactors have been built recently in the United States, EIA's cost estimates are based on foreign cost data. There are two marketable Generation III light-water reactors currently in operation, and another four are under construction in Asia [*79*]. Thus, the starting point for an estimate of building the "next" new U.S. advanced nuclear power plant was the realized cost of the two operating light-water nuclear units in Asia. In *AEO2004*, $2,083 per kilowatt (inclusive of all contingencies) is used as the realized cost for these two reactors [*80*].

The four units that are under construction in Asia will be completed over the next 5 years. The first new U.S. plant could not become operational until 2012 at the earliest. Thus, the construction of the first U.S. plant will benefit from experience gained in the construction of the four units in Asia.

For all advanced technologies that are in the early stages of commercialization, EIA assumes that, because of learning, U.S. capital costs will fall by 5 percent for each of the first three doublings of newly built capacity. The same learning factor is applied to the costs of the four advanced light-water reactors under construction in Asia. Thus, the cost reduction from learning in building four additional reactors (roughly 1.5 doublings of capacity) is about 8.5 percent. As a result, the assumed realized cost, inclusive of contingencies, of the sixth advanced light-water reactor in Asia when it is completed is $1,928. This is the estimate used in the projections [*81*].

As new U.S. nuclear plants are built, because of learning, EIA assumes that costs will continue to fall. For example, if 10 new units were constructed in the United States, costs would continue to fall to about $1,719 per kilowatt (inclusive of all contingencies) as a result of learning. Even if no nuclear plants were built in the United States, EIA assumes that costs would fall to about $1,752 per kilowatt by 2019. As shown in Figure 36, the *AEO2004* cost estimates are below realized costs for older U.S. plants and plants recently built abroad.

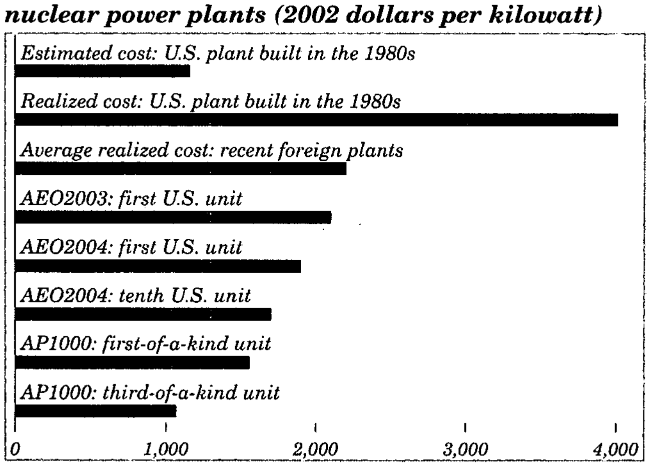
The vendors' estimates of construction lead times are generally about 36 to 48 months from the date of the first concrete pour to the date of initial system testing (or fuel loading). This definition of lead time is often used, because most of the funds are expended over that period. To compute interest costs, EIA uses a slightly different definition of lead times—namely, the time between the commencement of the licensing process to the date of commercial operation. The licensing process will take 12 to 24 months, and there will be an additional 6 months between fuel loading and commercial operation. Thus, EIA assumes a 6-year lead time.

In one of EIA's workshops, the issue of the time and cost for preparing a license application and the expenses incurred in obtaining the license were discussed. Some within the industry think an additional 4 years would be needed to prepare the application and license the first few plants, resulting in a 10-year total lead time. A small cost premium (up to 5 percent) is added by EIA to the cost of just the first four units built. This is called the "technological optimism factor." Because this factor gradually goes to zero as new nuclear plants are constructed, there will be an additional reduction in costs over and above the learning effects. This cost reduction, in part, captures the reduction in expenses associated with the 4-year reduction in lead times as a result of improvements in the licensing process.

Summary of the Projections

Over the past few years, most economic analyses of nuclear power have tended to compare the cost of generating electricity from nuclear technology with the cost of producing power from a combined-cycle natural-gas-fired power plant. As long as natural gas prices remain in the range of $2 to $3 per thousand cubic feet, the cost of building and operating a new gas-fired plant will be much less than the cost of a new coal-fired plant. Therefore, the assumption has been that nuclear power would compete with combined-cycle gas plants. With natural gas prices rising, however, new coal-fired power plants and, to some extent, renewable energy are becoming competitive with new natural gas units in many parts of the United States.

Figure 36. Estimates of overnight capital costs for nuclear power plants (2002 dollars per kilowatt)



The *AEO2004* reference case assumes that nuclear power plant construction costs will fall from $1,928 per kilowatt to $1,752 in 2019. On that basis, no new nuclear power plants would be built before 2025 in the reference case. In two advanced nuclear cases, vendor estimates for the AP1000 and ACR-700 reactors are used. In both advanced cases, the current level of nuclear capital costs is assumed to be lower than in the reference case, and cost reductions are assumed to be greater than in the reference case. Specifically, one advanced case—the vendor estimate case—is based on an average of the AP1000 and ACR-700 reactor first-of-a-kind and *n*th-of-a-kind costs [*82*]. In this case, costs would fall from $1,555 per kilowatt in 2004 to $1,149 in 2019. The second advanced nuclear case—the AP1000 case—uses just the vendor cost estimates for the AP1000. In this case, costs would fall from $1,580 per kilowatt to $1,081 in 2019.

In the AP1000 case, where costs fall to about $1,081 per kilowatt in 2019, EIA projects that about 26 gigawatts of new nuclear power plant capacity would be constructed and become operational by 2025. The 26 gigawatts of new nuclear power plant capacity would displace 19 gigawatts of coal-fired capacity and 7 gigawatts of mainly fossil-fuel-fired capacity. In the average cost case, where costs fall to $1,149 per kilowatt in 2019, 12.8 gigawatts of new nuclear power capacity would be built and become operational by 2025, displacing about 9.4 gigawatts of coal-fired capacity.

If the projections were extended beyond 2025, or if the cost reductions occurred more rapidly than assumed in the two advanced nuclear cases, the projected amount of new nuclear capacity would be much greater. The total assumed capital cost of a pulverized coal plant in 2005 is $1,170 per kilowatt—about 10 percent higher than the vendor's estimate of the AP1000 costs [*83*]. Coal and nuclear fuel costs are 10 mills and 4 mills per kilowatthour, respectively. Historically, non-fuel operating and maintenance costs are roughly the same for the two technologies. Given a nuclear capital cost estimate of $1,081 per kilowatt, both the capital and operating costs would therefore be less for nuclear than for coal-fired power plants. If the $1,081 per kilowatt estimate could be realized, it is possible that nuclear power could eventually be used to satisfy virtually all the baseload demand in the United States in future years.

The Issue of Risk

Another issue that received considerable attention in the EIA workshops was the financial risk in constructing and operating any power plant. There are risks associated with the use of natural gas, coal, and nuclear power. Natural-gas-fired power plants can be built in a few years and are relatively inexpensive, and thus there is little risk in their construction; however, because natural gas prices are volatile, there are risks involved with the operation of gas-fired power plants. Indeed, a number of the workshop participants noted that nuclear power can be used to hedge fuel price risks associated with gas plants.

Environmental factors aside, coal prices are relatively stable, and thus the fuel price risks associated with coal-fired power plants are small. Environmental regulations could change, however, especially with respect to global warming, with major impacts on the economics of operating coal plants. Thus, there are regulatory risks associated with the operation of coal-fired power plants. One workshop participant noted that firms have been able to finance the construction of coal-fired plants because of a perception that changes in environmental regulations will not occur for another 10 to 15 years, and by then the loans will have been repaid.

There are also regulatory risks involved with the construction and operation of nuclear power plants. According to a number of workshop participants, the financial community clearly has not completely discounted the cost overruns that occurred in the 1970s and 1980s. Thus, all the participants agreed that the nuclear industry must demonstrate that a nuclear power plant can be built on time and on budget. Further, the new licensing process has yet to be tested, and there is considerable uncertainty about how it will work. In fact, all the participants agreed that some type of support from a third party (the Federal Government) would be needed before the first few plants could be built.

If nuclear power plants are built in a deregulated environment, their owners—like the owners of any power plant—will be exposed to output price risk. Electricity prices might be lower than anticipated, resulting in insufficient revenues to cover all the operating costs, loan repayments, and returns to shareholders. As a result of market deregulation, electricity is now a commodity, and like any other commodity, in the short run electricity prices are extremely volatile and subject to "boom and bust" cycles. The events of the past few years suggest that if plants become operational in the "bust" part of a cycle, the result can be financial ruin.

Although all units are subject to output price risk, nuclear power plants are affected differently because of their relatively high capital costs and longer lead times. That is, because of nuclear power's relatively high capital costs, relatively more capital is "at risk." Moreover, the uncertainty of any forecast of electricity prices increases as the length of the forecast period increases (a 6-year forecast is more uncertain than a 2-year forecast). Because of nuclear power's relatively long lead times, electricity prices must be anticipated over a relatively long period, leading to more uncertainty.

All the workshop participants outside the nuclear industry argued that stable and predictable revenues resulting from long-term, fixed-price power purchase agreements or other financial or regulatory instruments are crucial to the financing of a nuclear power plant. Long-term (10 to 20 years) firm fixed price purchased power contracts are, however, very difficult and expensive to obtain. Moreover, as a recent EIA report noted, until some structural flaws in electric power markets are corrected, the use of financial derivatives to manage electricity price risk is limited [*84*]. Thus, at least in the short run, it is not clear whether it will be possible to obtain a stable stream of revenues from a nuclear (or other) power plant.

The advanced nuclear cases summarized above and presented in detail in the "Market Trends" section of this report assume that institutional and financial arrangements can be used to mitigate (or shift) output price risk at very little cost to decisionmakers. A fixed-price purchased power contract is one possible financial arrangement that would shift the risk to those holding the contract. Another possible institutional arrangement would be a consortium formed by a group of utilities and vendors to build nuclear power plants. In such a case, the risks would be spread among all the consortium members.

The Renewable Electricity Production Tax Credit

In the late 1970s and early 1980s, environmental and energy security concerns were addressed at the Federal level by several key pieces of energy legislation. Among them, the Public Utility Regulatory Policies Act of 1978 (PURPA), P.L. 95-617, required regulated power utilities to purchase alternative electricity generation from qualified generating facilities, including small-scale renewable generators; and the Investment Tax Credit (ITC), P.L. 95-618, part of the Energy Tax Act of 1978, provided a 10-percent Federal tax credit on new investment in capital-intensive wind and solar generation technologies [*85*].

The Energy Policy Act of 1992 (EPACT) included a provision that addresses problems with the ITC—specifically, the lack of incentives for operation of wind facilities. EPACT introduced the Renewable Electricity Production Tax Credit (PTC), a credit based on annual production of electricity from wind and some biomass resources. The initial tax credit of 1.5 cents per kilowatthour (1992 dollars) for the first 10 years of output from plants entering service by December 31, 1999, has been adjusted for inflation and is currently valued at 1.8 cents per kilowatthour (2002 dollars) [*86, 87*].

The original PTC applied to generation from tax-paying owners of wind plants and biomass power plants using fuel grown in a "closed-loop" arrangement—crops grown specifically for energy production, as opposed to byproducts of agriculture, forestry, urban landscaping, and other activities. In its early years, the PTC had little discernable effect on the wind and biomass industries it was designed to support. By 1999, however, when the provision was originally set to expire, U.S. wind capacity had begun growing again, and the PTC supported the development of more than 500 megawatts of new wind capacity in California, Iowa, Minnesota, and other States. Wind power development was also encouraged by State-level programs, such as the mandate in Minnesota for 425 megawatts of wind power by 2003 as part of a settlement with Northern States Power (now Xcel Energy) to extend on-site storage of nuclear waste at its nuclear facility [*88*].

In 1999, the PTC was allowed to expire as scheduled, but within a few months it was retroactively extended through the end of 2001 [*89*], and poultry litter was added to the list of eligible biomass fuels. Although wind power development slowed significantly in 2000, 2001 was a record year with as much as 1,700 megawatts installed [*90*]. Again, State and local programs, including a significant renewable portfolio standard (RPS) program in Texas, also supported new wind installations.

The PTC was allowed to expire again on December 31, 2001, while Congress worked on a comprehensive new energy policy bill. It was retroactively extended a second time to December 31, 2003, as part of an omnibus package of extended tax credits passed in response to the economic downturn and terrorist attacks of 2001 [*91*].

Like the 1999 expiration and extension, the extension of the PTC in 2002 was followed by a lull in wind power development. And again, a review of confirmed industry announcements indicates that 2003 will see total new installations of more than 1,600 megawatts of wind capacity. Significantly, while many 2003 builds still rely on multiple incentives (for example, the PTC plus a State program) to achieve economic viability, there are some in Oklahoma and other States that have been developed with little government support beyond the PTC [*92*].

With reductions in capital costs and increases in capacity factors [*93*], wind power technology has improved since the introduction of the ITC and subsequent replacement by the PTC. It is likely that the installations spurred by these incentives allowed the industry to "learn by doing" and thus contributed to improvement of the technology. There were, however, other factors that contributed to cost reductions during the period, including government-funded research and development (both domestic and international) and large markets for wind power technology that were created by subsidy programs in other countries, especially, Denmark and Germany.

The *AEO2004* reference case, assuming no extension of the PTC beyond 2003, projects that the levelized cost of electricity generated by wind plants coming on line in 2006 (over a 20-year financial project life) would range from approximately 4.5 cents per kilowatthour at a site with excellent wind resources [*94*] to 5.7 cents per kilowatthour at less favorable sites. To incorporate the effect of the current 1.8-cent tax credit over the 10-year eligibility period for those plants, the projections account for both the tax implications and the time value of the subsidy. As a tax credit, the PTC represents 1.8 cents per kilowatthour of tax-free money to a project owner. If the owner did not receive the tax credit and wanted to recoup that 1.8 cents with taxable revenue from electricity sales, the owner would have to add 2.8 cents to the sales price of each kilowatthour, assuming a 36-percent marginal tax rate. Applying the same assumptions used to derive the 4.5-cent total levelized cost of wind energy over a 20-year project life, the levelized value of the PTC to the project owner is approximately 2 cents per kilowatthour.

In the reference case, the levelized cost for electricity from new natural gas combined-cycle plants is 4.7 cents per kilowatthour, and for new coal-fired plants the projected cost in 2007 is 4.9 cents per kilowatthour [*95*]. Thus, it is easy to see how the PTC could make wind plants an attractive investment in the current electricity market.

In addition to generation cost comparisons, the difference between an intermittent resource (wind plants) and a dispatched resource (coal- and gas-fired plants) must also be considered. Dispatched generation provides "value" to the grid because it contributes more to the reliability of the system and is generally available to meet daily and seasonal load requirements. An intermittent resource has only limited ability to contribute to grid reliability and does not necessarily produce energy in a daily or seasonal pattern that matches daily or seasonal load variations.

Given the uncertainty regarding both the short-term extension of the PTC and its long-term fate, EIA developed three alternative PTC cases for *AEO2004*. The cases are not meant to indicate a preferred or even likely policy outcome, but rather to provide a useful range of possible outcomes to provide insight into the effects of the PTC program on future energy markets relative to the reference case forecast, which assumes no new PTC subsidy beyond 2003.

The 3-year PTC case assumes that the PTC is extended to December 31, 2006, as provided for in the Energy Bill Conference Report adopted in the House and now before the Senate. The extended program continues to cover wind and currently eligible biomass fuels, and coverage is extended to "open loop" biomass sources (primarily waste or byproducts from other processes) and landfill gas generation, as provided for in the Conference agreement. Otherwise, the structure of the program is assumed to remain the same as under current law.

The 9-year PTC case assumes extension of the program to December 31, 2012, as well as the expansion to all biomass and landfill gas resources. All other assumptions remain the same as under current law. This case assumes a single 9-year extension, rather than a series of short-term expirations and reauthorizations [*96*]. Because the history of the PTC indicates that such a cycle can affect the dynamics of industry expansion, and because the specific tax-liability limitations of project owners are unknown, this case provides upper-end estimates of capacity additions resulting from the PTC with a 9-year extension.

The 9-year half PTC case also assumes an extension of the PTC to 2012 and expansion to biomass and landfill gas resources. In this case, however, a modified program is assumed, with the value of the tax credit set at 0.9 cents per kilowatthour (2003 dollars) for the first 10 years of plant operation, indexed to inflation. The assumptions for this case do not reflect any expectation or proposal for the policy but were selected to provide insight into the limitations of the analysis—specifically, uncertainty about the ability of industry to capture the full tax credit value—as well as an indication of program effects if the value of the tax credit were reduced.

The reference case does not assume the installation of any planned capacity for which construction is indicated to be dependent on extension of the PTC. Such planned capacity is included in the three sensitivity cases through the assumed final extension date—2006 in the 3-year PTC case and 2012 in the 9-year PTC case and the 9-year half PTC case. Otherwise, the sensitivity cases follow the reference case assumptions and are based on a fully integrated run of the National Energy Modeling System (NEMS), ensuring that price feedback effects (such as in natural gas markets) are fully accounted for.

Table 18 compares the key results of the three PTC sensitivity cases with the reference case. The 3-year PTC case, with an expiration date of December 2006, results in an additional 7.9 gigawatts of new wind capacity by 2010 compared to the reference case. By 2025, however, new wind capacity in the 3-year PTC case is only 7.8 gigawatts higher than in the reference case. Between 2007 (after the PTC expires) and 2025, 13.5 gigawatts of new wind capacity is constructed in the 3-year PTC case, compared with 8.6 gigawatts in the reference case for the same period. After 2010, the 3-year PTC case does not project additional wind capacity builds beyond those in the reference case. Compared with the reference case, no additional construction of new biomass facilities by 2010 is projected in the 3-year PTC case. Biomass facilities require longer construction lead times than the 3-year extension and therefore are not able to take advantage of the 3-year extension.

The 3-year PTC case projects the cumulative cost to the U.S. Treasury from the 3-year extension to be $1.7 billion (2002 dollars), using a 7 percent real discount rate [97]. This represents the tax revenue not recovered from the tax-paying owners of all wind and dedicated biomass facilities placed in service from the beginning of 2004 to December 31, 2006. It does not include lost revenue from existing facilities (placed in service before December 31, 2003) but does include facilities already planned or committed to be built after 2003.

The 9-year PTC case, with an expiration date of December 2012, results in an additional 32.3 gigawatts of new wind capacity by 2010 compared to the reference case. By 2015, that has increased to 54.7 gigawatts over the reference case, but by 2025, the 9-year PTC case only has an additional 49.4 gigawatts over the reference case. The cumulative cost to the U.S. Treasury for a 9-year, full value extension is $33 billion, compared to the reference case with no extension.

The extension to 2012 also provides an opportunity for new biomass facilities to be constructed to take advantage of the tax credit. By 2010, an additional 2.2 gigawatts of operating biomass capacity is projected in the 9-year PTC case relative to the reference case, increasing to 8.5 gigawatts over the reference case in 2015 and 10 gigawatts in 2025. In 2025, the 13.7 gigawatts of installed biomass capacity in the 9-year PTC case is projected to generate 91 billion kilowatthours, in addition to 230 billion kilowatthours of projected generation from 65.4 gigawatts of installed wind capacity. Although the additional biomass

Table 18. Key projections for renewable electricity in the reference and PTC extension cases, 2010 and 2025

	2003	2010				2025			
Projection	*Reference*	*Reference*	*3-year PTC*	*9-year PTC*	*9-year half PTC*	*Reference*	*3-year PTC*	*9-year PTC*	*9-year half PTC*
Electric power sector net summer capacity (gigawatts)									
Municipal solid waste and landfill gas	3.6	3.9	4.6	4.7	4.4	4.0	4.6	4.7	4.5
Wood and other biomass	1.9	2.2	2.1	4.4	3.2	3.7	4.6	13.7	8.1
Wind	6.5	8.0	15.9	40.3	23.4	16.0	23.8	65.4	38.8
Total electric power industry	936.9	931.7	937.5	958.1	943.3	1,169.9	1,176.7	1,221.0	1,191.7
Electric power sector generation (billion kilowatthours)									
Municipal solid waste and landfill gas	25.6	28.1	33.7	34.5	32.3	28.5	33.9	34.7	32.4
Wood and other biomass	15.7	23.5	23.4	28.4	26.3	29.2	33.4	90.9	51.8
Dedicated plants	10.8	13.3	13.0	22.5	17.5	22.9	28.4	90.9	51.0
Co-firing	5.0	10.3	10.4	6.0	8.8	6.3	5.0	0.0	0.8
Wind	17.4	24.1	52.5	139.3	79.2	53.2	81.8	230.0	136.5
Total electricity generation	3,900.0	4,510.0	4,511.0	4,523.0	4,512.0	5,787.0	5,787.0	5,805.0	5,790.0

capacity projected in the 9-year PTC case relative to the reference case is only 21 percent of the wind capacity added by 2025, because of its higher relative capacity factor, the projected generation from the additional biomass capacity is almost 40 percent of that from the additional wind capacity.

Almost 6.3 billion kilowatthours of biomass co-firing (that is, biomass fuel burned with coal in existing coal-fired plants) is projected in the reference case by 2025. In the 9-year PTC case, no co-fired generation is expected by 2025, largely because the more efficient new dedicated biomass facilities would be able to pay feedstock suppliers higher fuel premiums than the less efficient existing coal facilities retrofitted with co-firing equipment. Total biomass generation (dedicated plus co-firing) in the 9-year PTC case is more than triple total biomass generation in the reference case (91 billion kilowatthours and 29 billion kilowatthours, respectively).

In the 9-year half PTC case, substantial projected increases in wind capacity relative to the reference case projection reflect wind power costs that are, without subsidy, very close to being competitive. Although the 9-year half PTC case projects 27 gigawatts less installed wind capacity in 2025 than the 9-year PTC case, it projects almost 23 gigawatts more than in the reference case. Like the 9-year PTC case, the 9-year half PTC case projects significant leveling off of new wind installations after 2012, when eligibility for the subsidy ends. Between 2015 and 2025, wind capacity in the 9-year half PTC case increases by only 1.1 gigawatts, compared with 5.5 gigawatts of capacity growth in the reference case. Although by 2015 the basic unsubsidized levelized cost [*98*] of wind energy is reduced by about 0.5 cents per kilowatthour below the reference case for the same year, fewer low-cost resources are available once the subsidy has expired (having already been developed with the subsidy in place), and fewer attractive resources are available for development. The cumulative cost of the PTC extension to the U.S. Treasury in the 9-year half PTC case is projected to be $16 billion.

The projection for dedicated biomass capacity in 2025 in the 9-year half PTC case is 4.3 gigawatts higher than in the reference case. Although the additional capacity is sufficient to draw substantial biomass feedstock from the co-firing market, it does not completely eliminate it. Co-firing in 2025 in the 9-year half PTC case is only about 0.8 billion kilowatthours below the reference case projection of 6.3 billion kilowatthours.

U.S. Greenhouse Gas Intensity

On February 14, 2002, President Bush announced the Administration's Global Climate Change Initiative [*99*]. A key goal of the Climate Change Initiative is to reduce U.S. greenhouse gas intensity by 18 percent over the 2002 to 2012 time frame. For the purposes of the initiative, greenhouse gas intensity is defined as the ratio of total U.S. greenhouse gas emissions to economic output.

AEO2004 projects energy-related carbon dioxide emissions, which represented approximately 83 percent of total U.S. greenhouse gas emissions in 2002. Projections for other greenhouse gases are based on projected rates of growth in their emissions, published in the U.S. Department of State's *Climate Action Report 2002* [*100*]. Table 19 combines the *AEO2004* reference case projections for energy-related carbon dioxide emissions with the projections for other greenhouse gases.

Table 19. Projected changes in U.S. greenhouse gas emissions, gross domestic product, and greenhouse gas intensity, 2002-2025

	Projection			*Percent Change*	
Measure	***2002***	***2012***	***2025***	***2002-2012***	***2002-2025***
Greenhouse gas emissions (million metric tons carbon dioxide equivalent)					
Energy-related carbon dioxide	5,729	6,763	8,142	18.0	42.1
Methane	613	623	616	1.6	0.5
Nitrous oxide	333	358	403	7.5	21.1
Gases with high global warming potential	121	271	595	124.3	393.0
Other carbon dioxide and adjustments for military and international bunker fuel	66	73	84	10.3	26.1
Total greenhouse gases	***6,862***	***8,087***	***9,839***	***17.8***	***43.4***
Gross domestic product (billion 1996 dollars)	9,440	12,906	18,520	36.7	96.2
Greenhouse gas intensity (thousand metric tons carbon dioxide equivalent per billion 1996 dollars of gross domestic product)	727	627	531	-13.8	-26.9

According to the combined emissions projections in Table 19, the greenhouse gas intensity of the U.S. economy is expected to decline by nearly 14 percent between 2002 and 2012, and by 27 percent between 2002 and 2025. The Administration's goal of reducing greenhouse gas intensity by 18 percent by 2012 would require additional emissions reductions of about 394 million metric tons carbon dioxide equivalent.

Although *AEO2004* does not include cases that specifically address alternative assumptions about greenhouse gas intensity, the integrated high technology case does give some indication of the feasibility of meeting the 18-percent reduction target. In the integrated high technology case, which combines the high technology cases for the residential, commercial, industrial, transportation, and electric power sectors,carbon dioxide emissions in 2012 are projected to be 175 million metric tons less than in the *AEO2004* reference case. As a result, U.S. greenhouse gas intensity would fall by almost 16 percent over the 2002-2012 period, still somewhat short of the Administration's goal of 18 percent (Figure 37). An 18-percent decline in intensity is projected to occur by 2014 in the integrated high technology case, as compared with 2016 in the reference case.

Figure 37. Projected improvement in U.S. greenhouse gas intensity, 2002-2025 (percent)