UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	Docket Nos. 52-012-COL 52-013-COL
STP NUCLEAR OPERATING COMPANY	)	
(South Texas Project Units 3 and 4)	)	June 14, 2010

STP NUCLEAR OPERATING COMPANY'S ANSWER OPPOSING NEW CONTENTIONS BASED ON THE DRAFT ENVIRONMENTAL IMPACT STATEMENT

I. INTRODUCTION

Pursuant to 10 C.F.R. § 2.309(h) and the October 20, 2009 Initial Scheduling Order, STP Nuclear Operating Company ("STPNOC"), applicant in the above-captioned proceeding, hereby submits this Answer opposing the new contentions proffered by the Intervenors on May 19, 2010.[1] The contentions allege inadequacies in the Nuclear Regulatory Commission ("NRC") Staff's March 2010 Draft Environmental Impact Statement ("DEIS") for the construction and operation of South Texas Project ("STP") Units 3 and 4.[2] Specifically, the Intervenors seek admission of Contention DEIS-1 (need for power), Contention DEIS-2 (global warming), Contention DEIS-3 (comparison of CO_2 emissions from nuclear, wind, and solar power), Contention DEIS-4 (greenhouse gas mitigation measures during construction), Contention DEIS-5 (groundwater and nonradiological health), and Contention DEIS-6 (water use by the Las

1 Intervenors' Motion for Leave to File New Contentions Based on the Draft Environmental Impact Statement (May 19, 2010) ("Motion").

2 NUREG-1937, Draft Environmental Impact Statement for Combined Licenses (COLs) for South Texas Project Electric Generating Station Units 3 and 4, Draft Report for Comment, Vols. 1 & 2 (Mar. 2010), *available at* ADAMS Accession Nos. ML100700327 and ML100700333.

Brisas power plant).[3] The new contentions state that they are supported by comments on the DEIS from Mr. David Power ("Power Comments").

As demonstrated below, the Intervenors' new contentions should be denied in their entirety because they do not meet the NRC's late-filed contention requirements set forth in 10 C.F.R. §§ 2.309(c) and (f)(2), or the contention admissibility requirements codified in 10 C.F.R. § 2.309(f)(1). Contrary to 10 C.F.R. § 2.309(f)(2), the Intervenors have not claimed, much less demonstrated, that any of their new contentions are based on "data or conclusions" in the DEIS that "differ significantly" from those in STPNOC's Environmental Report ("ER") for STP Units 3 and 4. Additionally, most of the information relied upon by the Intervenors as support for these contentions has been available for many months or years. Indeed, most of the new contentions are embellished versions of previously rejected contentions. Furthermore, to the extent that the Intervenors cite any new information, it is not materially different from information previously available to them.

Additionally, the new contentions raise issues that are not material to the Staff's environmental findings, fail to provide adequate factual or legal support for alleged deficiencies in the DEIS, and fail to establish a genuine dispute of material fact relative to the Staff's National Environmental Policy Act ("NEPA") analysis. Accordingly, the contentions also should be rejected for failing to meet the admissibility requirements set forth in 10 C.F.R. § 2.309(f)(1)(iv)-(vi).

II. PROCEDURAL BACKGROUND

On September 20, 2007, STPNOC submitted an application to the NRC for combined licenses ("COLs") for STP Units 3 and 4.[4] The Sustainable Energy and Economic Development

[3] To prevent confusion with other contentions filed by the Intervenors in this proceeding, the number system used in this Answer for the new contentions includes a "DEIS" designation for "Draft Environmental Impact Statement."

Coalition, Susan Dancer, the South Texas Association for Responsible Energy, Daniel A. Hickl, Public Citizen, and Bill Wagner ("Intervenors") filed a "Petition for Intervention and Request for Hearing" ("Petition") on April 21, 2009, alleging 28 separate contentions.

The Petition included proposed contentions on topics similar to those presented in Contentions DEIS-1 through 6, including:

- Contention 11 - - The Intervenors alleged that the COL application did not adequately consider the impacts of global warming on plant operations, including water availability.[5]
- Contention 20 - - The Intervenors alleged that the COL application did not adequately consider the greenhouse gas impacts of the uranium fuel cycle and did not adequately compare these greenhouse gas effects with alternative energy technologies.[6]
- Contention 23 - - The Intervenors alleged that the COL application did not adequately consider alternative energy technologies.[7]
- Contention 26 - - The Intervenors alleged that the COL application did not adequately evaluate a need for power from STP Units 3 and 4.[8]

The Atomic Safety and Licensing Board ("Board") rejected all of these contentions.[9]

The NRC issued the DEIS for STP Units 3 and 4 in March 2010. The Staff's preliminary recommendation from an environmental perspective is that the COLs for STP Units 3 and 4 should be issued.[10]

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4 South Texas Project Nuclear Operating Company; Notice of Receipt and Availability of Application for a Combined License, 72 Fed. Reg. 60,394, 60,394 (Oct. 24, 2007).

5 Petition at 37-40.

6 *Id.* at 44-45.

7 *Id.* at 48-57.

8 *Id.* at 62-64.

9 *See S. Tex. Project Nuclear Operating Co.* (South Texas Project Units 3 & 4), LBP-09-25, 70 NRC __, slip op. at 12-16 (Sept. 29, 2009); *S. Tex. Project Nuclear Operating Co.* (South Texas Project Units 3 & 4), LBP-09-21, 70 NRC __, slip op. at 33-36, 42-47, 52-56 (Aug. 27, 2009).

10 DEIS at 10-27.

III. LEGAL STANDARDS

A. Timeliness Requirements

Under 10 C.F.R. § 2.309(f)(2), proposed contentions that raise issues arising under NEPA must be filed based on an applicant's ER. An intervenor may amend environmental contentions or file new contentions "if there are data or conclusions in the NRC draft or final environmental impact statement, environmental assessment, or any supplements relating thereto, that *differ significantly* from the data or conclusions in the applicant's documents."[11]

The requirement of 10 C.F.R. § 2.309(f)(2) that data or conclusions "differ significantly" is "inextricably intertwined with the requirement that the newly supplied information be material to the outcome of the proceeding."[12] In other words, new information is not significantly different if it is not material to the Staff's NEPA determination.[13]

Furthermore, an intervenor cannot avoid the requirement in 10 C.F.R. § 2.309(f)(2) by contending that the DEIS has omissions. For example, in *Private Fuel Storage*, the intervenor filed a new contention asserting that certain information was omitted from the DEIS.[14] The information, however, also was omitted from the applicant's ER.[15] The licensing board determined that the omission from the DEIS did not constitute "new or different data or conclusions," and ruled that "[a]n intervenor that awaits the publication of a DEIS or FEIS [Final

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11 10 C.F.R. § 2.309(f)(2) (emphasis added); *see also Private Fuel Storage, LLC* (Independent Spent Fuel Storage Installation), LBP-00-27, 52 NRC 216, 223 (2000) (quoting *Sacramento Mun. Util. Dist.* (Rancho Seco Nuclear Generating Station), LBP-93-23, 38 NRC 200, 251 (1993), *petition for review and motion for directed certification denied*, CLI-94-2, 39 NRC 91 (1994)), *review denied in relevant part*, CLI-04-4, 59 NRC 31, 45 (2004).

12 *Exelon Generation Co., LLC* (Early Site Permit for Clinton ESP Site), LBP-05-19, 62 NRC 134, 163 (2005), *review denied*, CLI-05-29, 62 NRC 801 (2005), *petition for review denied sub nom., Envtl. Law & Policy Ctr. v. NRC*, 470 F.3d 676 (7th Cir. 2006).

13 *See id.*

14 *Private Fuel Storage*, LBP-00-27, 52 NRC at 223.

15 *Id.*

Environmental Impact Statement] before filing a contention for which the intervenor has sufficient information does so 'at its peril.'"[16]

If an intervenor does not demonstrate that the data or conclusions in the DEIS are significantly different from those in the ER, 10 C.F.R. § 2.309(f)(2) states that an intervenor may file amended or new contentions "only with leave of the presiding officer" upon a showing that all three of the following criteria are met:

> (i) The information upon which the amended or new contention is based was *not previously available*;
>
> (ii) The information upon which the amended or new contention is based is *materially different than information previously available*; and
>
> (iii) The amended or new contention has been *submitted in a timely fashion* based on the availability of the subsequent information.
> (Emphasis added).

In the Commission's words, a new or amended NEPA contention "is not an occasion to raise additional arguments that could have been raised previously."[17]

If an intervenor cannot satisfy the requirements of 10 C.F.R. § 2.309(f)(2), then a contention is considered "nontimely,"[18] and the intervenor must demonstrate that it satisfies the eight-factor balancing test in 10 C.F.R. § 2.309(c)(1)(i)-(viii).[19] The first factor identified in that

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16 *Id.* (quoting *La. Energy Servs., L.P.* (Claiborne Enrichment Center), LBP-94-11, 39 NRC 205, 212 (1994)).

17 *Duke Energy Corp.* (McGuire Nuclear Station, Units 1 & 2; Catawba Nuclear Station, Units 1 & 2), CLI-02-28, 56 NRC 373, 385-86 (2002). As the D.C. Circuit explained, it is "unreasonable to suggest that the NRC must disregard its procedural timetable every time a party realizes based on NRC environmental studies that maybe there was something after all to a challenge it either originally opted not to make or which simply did not occur to it at the outset." *Union of Concerned Scientists v. NRC*, 920 F.2d 50, 55 (D.C. Cir. 1990).

18 *See* Initial Scheduling Order at 8-9.

19 *See* 10 C.F.R. § 2.309(c)(2) ("The requestor/petitioner *shall* address the factors in paragraphs (c)(1)(i) through (c)(1)(viii) of this section in its nontimely filing.") (emphasis added). These factors include: (i) Good cause, if any, for the failure to file on time; (ii) The nature of the requestor's/petitioner's right under the Act to be made a party to the proceeding; (iii) The nature and extent of the requestor's/petitioner's property, financial or other interest in the proceeding; (iv) The possible effect of any order that may be entered in the proceeding on the requestor's/petitioner's interest; (v) The availability of other means whereby the requestor's/petitioner's interest will be protected; (vi) The extent to which the requestor's/petitioner's interests will be represented by existing parties; (vii) The extent to which

regulation, whether "good cause" exists for the failure to file on time, is entitled to the most weight.[20] Without good cause, a "petitioner's demonstration on the other factors must be particularly strong."[21]

The intervenor has the burden of showing that these criteria have been satisfied.[22] If the intervenor's pleading does not address the criteria, it should be summarily denied.[23]

B. Admissibility Requirements

In addition to complying with the requirements in 10 C.F.R. §§ 2.309(c) and (f)(2), an intervenor must show that a late-filed contention meets the contention admissibility requirements of 10 C.F.R. § 2.309(f)(1)(i)-(vi).[24] These requirements are discussed in detail in STPNOC's May 18, 2009 Answer opposing the Petition, and a briefer discussion of the important contention admissibility requirements is set forth below.

Under 10 C.F.R. § 2.309(f)(1), a hearing request "must set forth with particularity the contentions sought to be raised." In addition, that section specifies that each contention must: (1) provide a specific statement of the legal or factual issue sought to be raised; (2) provide a brief explanation of the basis for the contention; (3) demonstrate that the issue raised is within the scope of the proceeding; (4) demonstrate that the issue raised is material to the findings the

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the requestor's/petitioner's participation will broaden the issues or delay the proceeding; and (viii) The extent to which the requestor's/petitioner's participation may reasonably be expected to assist in developing a sound record. *Id.* § 2.309(c)(1).

20 *See State of New Jersey* (Department of Law and Public Safety's Requests Dated Oct. 8, 1993), CLI-93-25, 38 NRC 289, 296 (1993).

21 *Tex. Utils. Elec. Co.* (Comanche Peak Steam Elec. Station, Units 1 & 2), CLI-92-12, 36 NRC 62, 73 (1992) (quoting *Duke Power Co.* (Perkins Nuclear Station, Units 1, 2, & 3), ALAB-431, 6 NRC 460, 462 (1977)).

22 *See Balt. Gas & Elec. Co.* (Calvert Cliffs Nuclear Power Plant, Units 1 & 2), CLI-98-25, 48 NRC 325, 347 & n.9 (1998).

23 *Id.*

24 *See Sacramento Mun. Util. Dist.* (Rancho Seco Nuclear Generating Station), CLI-93-12, 37 NRC 355, 362-63 (1993); *see also Crow Butte Res., Inc.* (In Situ Leach Facility, Crawford, Nebraska), CLI-09-9, 69 NRC 331, 364 (2009) (stating that the timeliness of the late-filed contention need not be evaluated because the contention did not satisfy the contention admissibility requirements of 10 C.F.R. § 2.309(f)(1)).

NRC must make to support the action that is involved in the proceeding; (5) provide a concise statement of the alleged facts or expert opinions, including references to specific sources and documents that support the petitioner's position and upon which the petitioner intends to rely; and (6) provide sufficient information to show that a genuine dispute exists with regard to a material issue of law or fact.[25]

The purpose of these six criteria is to "focus litigation on concrete issues and result in a clearer and more focused record for decision."[26] The Commission has stated that it "should not have to expend resources to support the hearing process unless there is an issue that is appropriate for, and susceptible to, resolution in an NRC hearing."[27]

The Commission's rules on contention admissibility are "strict by design."[28] The rules were "toughened . . . in 1989 because in prior years 'licensing boards had admitted and litigated numerous contentions that appeared to be based on little more than speculation.'"[29] As the Commission has stated:

> Nor does our practice permit "notice pleading," with details to be filled in later. Instead, we require parties to come forward at the outset with sufficiently detailed grievances to allow the adjudicator to conclude that genuine disputes exist justifying a commitment of adjudicatory resources to resolve them.[30]

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[25] *See* 10 C.F.R. § 2.309(f)(1)(i)-(vi).

[26] Final Rule, Changes to Adjudicatory Process, 69 Fed. Reg. 2182, 2202 (Jan. 14, 2004).

[27] *Id.*

[28] *Dominion Nuclear Conn., Inc.* (Millstone Nuclear Power Station, Units 2 & 3), CLI-01-24, 54 NRC 349, 358 (2001).

[29] *Id.* (citing *Duke Energy Corp.* (Oconee Nuclear Station, Units 1, 2, & 3), CLI-99-11, 49 NRC 328, 334 (1999)).

[30] *N. Atl. Energy Serv. Corp.* (Seabrook Station, Unit 1), CLI-99-6, 49 NRC 201, 219 (1999).

The failure to comply with any one of the six admissibility criteria is grounds for rejecting a new contention.[31]

IV. THE NEW CONTENTIONS DO NOT SATISFY 10 C.F.R. §§ 2.309(c) AND (f)(2)

A. The New Contentions Should Be Rejected for Not Addressing the Regulatory Requirements

The Intervenors did not address the criteria in 10 C.F.R. §§ 2.309(c) and (f)(2). The Intervenors have the burden of showing that these criteria have been satisfied.[32] The Commission has affirmed rejection of late-filed contentions that did not address these late-filing criteria.[33] Because the Intervenors have not met their burden for late-filed contentions, their Motion and the associated contentions should be summarily rejected.[34]

B. The New Contentions Do Not Relate to Data or Conclusions in the DEIS that Differ Significantly from Those in the ER

As discussed above, 10 C.F.R. § 2.309(f)(2) states that NEPA contentions must be filed based on the ER, and new contentions can only be filed based on the DEIS if data or conclusions in the DEIS "differ significantly" from those in the ER. For the reasons discussed below, the new contentions do not meet this requirement.

First, the Motion and the Power Comments attached to the Motion do not mention, much less discuss, the ER for STP Units 3 and 4. Thus, the Intervenors have not demonstrated that the new contentions are based on data or conclusions in the DEIS that differ significantly from those in the ER, because they have not discussed the ER.

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31 *See* Final Rule, Changes to Adjudicatory Process, 69 Fed. Reg. at 2221; *see also Private Fuel Storage, L.L.C.* (Independent Spent Fuel Storage Installation), CLI-99-10, 49 NRC 318, 325 (1999).

32 *See Calvert Cliffs*, CLI-98-25, 48 NRC at 347 & n.9.

33 *See, e.g.*, *Dominion Nuclear Conn., Inc.* (Millstone Nuclear Power Station, Unit 3), CLI-09-5, 69 NRC 115, 126 (2009) ("The Board correctly found that failure to address the requirements [of 10 C.F.R. §§ 2.309(c) and (f)(2)] was reason enough to reject the proposed new contentions.").

34 *See Calvert Cliffs*, CLI-98-25, 48 NRC at 347.

Second, the new contentions filed by the Intervenors are generally contentions of omission and claim that the DEIS omitted discussion of various topics or documents. In this regard, the Intervenors could have raised the same contentions of omission with respect to the adequacy of the ER for STP Units 3 and 4. As discussed above, the licensing board in *Private Fuel Storage* determined that an omission of information from the DEIS did not constitute "new or different data or conclusions" when that information also was not contained in the ER.[35]

Finally, the data and conclusions in the DEIS are not significantly different than those in the ER. For example:

- Contention DEIS-1 (need for power) – Both the DEIS and the ER conclude, based upon studies performed by the Electric Reliability Council of Texas ("ERCOT"), that there is a need for power from STP Units 3 and 4.[36]
- Contention DEIS-2 (global warming) – Both the ER and the DEIS conclude that there will be sufficient cooling water for STP Units 3 and 4.[37] Neither the DEIS nor the ER discusses various allegations of the Intervenors related to global warming, including allegations regarding increased salinity impacts on plant operation; the comparative impacts on surface water and groundwater quality from nuclear, wind, and solar power; and impacts of global warming on cooling water temperature.[38]

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[35] *Private Fuel Storage*, LBP-00-27, 52 NRC at 223.

[36] DEIS § 8; ER § 8 (Rev. 3), *available at* ADAMS Accession No. ML092931600.

[37] DEIS § 7.2.1.1; ER § 2.3.2 (Rev. 3), *available at* ADAMS Accession No. ML092931535.

[38] *See, e.g.*, DEIS §§ 5, 9; ER §§ 5, 9 (Rev. 3), *available at* ADAMS Accession No. ML092931600. Basis A of Contention DEIS-2 also argues that the DEIS has contradictory statements regarding the cumulative effects of greenhouse gas emissions. As discussed in Section V.B below, the statements in question are not contradictory.

- Contention DEIS-3 (comparison of CO_2 emissions from nuclear, wind, and solar power) – Both the DEIS and the ER conclude that wind and solar power alone are not reasonable alternatives for producing baseload power.[39] Therefore, neither the DEIS nor the ER compares the CO_2 emissions by nuclear, wind, and solar power facilities.[40]
- Contention DEIS-4 (greenhouse gas mitigation measures during construction) – Both the DEIS and the ER conclude that impacts to air quality (including gaseous emissions) would be SMALL and that mitigation measures beyond those identified by STPNOC are not warranted.[41]
- Contention DEIS-5 (groundwater and nonradiological health) – Both the DEIS and the ER conclude that the cumulative impacts on groundwater and nonradiological health would be SMALL.[42]
- Contention DEIS-6 (water use by the Las Brisas power plant) – Both the DEIS and the ER discuss use of water from the Colorado River in general (including the existing water rights that are proposed to be transferred to the Las Brisas plant), but do not mention use of water by the Las Brisas power plant specifically.[43]

In summary, the fact that a DEIS has been issued for STP Units 3 and 4 does not give the Intervenors an unrestricted right to file new contentions - - in order to avoid the need to comply with the requirements for late-filed contentions, the Intervenors must show that the DEIS differs significantly from the ER. The Intervenors have ignored this standard set forth in 10 C.F.R. §

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39 DEIS §§ 9.2.3.2, 9.2.3.3; ER §§ 9.2.2.3, 9.2.3.3 (Rev. 3), *available at* ADAMS Accession No. ML092931591.

40 DEIS § 9.2; ER § 9.2 (Rev. 3), *available at* ADAMS Accession No. ML092931591.

41 *See* DEIS at 4-63; ER § 4.4.1.3 (Rev. 3), *available at* ADAMS Accession No. ML092931558.

42 *See* DEIS at 7-16, 7-47; ER § 10.5S (Rev. 3), *available at* ADAMS Accession No. ML092931598.

43 *See* DEIS at 2-33; ER § 2.3.2.1 (Rev. 3), *available at* ADAMS Accession No. ML092931535.

2.309(f)(2) for DEIS contentions. Because the Intervenors have not met the standards for DEIS contentions, they must satisfy the three criteria in 10 C.F.R. § 2.309(f)(2)(i)-(iii). As discussed below, the Intervenors have not done so.

C. The New Contentions Do Not Satisfy the Criteria in 10 C.F.R. § 2.309(f)(2)(i)-(iii)

The new contentions do not satisfy the late-filed contention criteria in 10 C.F.R. § 2.309(f)(2). In particular, 10 C.F.R. § 2.309(f)(2)(iii) requires that a new contention be "submitted in a timely fashion based on the availability of the subsequent information." The Initial Scheduling Order clarifies that a new contention "shall be deemed timely under 10 C.F.R. § 2.309(f)(2)(iii) if it is filed . . . within thirty (30) days of the date when the new and material information on which it is based first becomes available."[44] The Motion was filed on May 19, 2010; therefore, new contentions must be based on information after April 19, 2010 to meet the 10 C.F.R. § 2.309(f)(2)(iii) timeliness requirement.

A table identifying all of the references in the Motion and the Power Comments is provided as STP Attachment 1 at the end of this Answer. As shown on this table, all but four of the references cited by the Intervenors are dated prior to April 19, 2010 and do not satisfy 10 C.F.R. § 2.309(f)(2)(iii). Therefore, the Intervenors must satisfy the requirements of 10 C.F.R. § 2.309(c) for those references.

The remaining four documents (dated after April 19, 2010), which are bolded in the table provided as STP Attachment 1, do not satisfy the requirement found in 10 C.F.R. § 2.309(f)(2)(ii) that "[t]he information upon which the amended or new contention is based is materially different than information previously available." In this regard, NRC tribunals have

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44 Initial Scheduling Order at 8.

held that unavailability of a document does not constitute good cause for late filing if a contention's "factual predicate" was otherwise available.[45]

The first document, Nexant's "Measurement and Verification of CPS Energy's 2009 DSM Program Offerings" (April 26, 2010), was referenced by the Intervenors as part of Contention DEIS-1.[46] The Intervenors reference this document to demonstrate that CPS Energy achieved a peak reduction of 44.7 MW due to Demand Side Management ("DSM") efforts.[47] CPS Energy's DSM efforts are well known and are discussed on the company's website.[48] In fact, this website provides a November 2008 presentation also by Nexant that discusses DSM possibilities, including the potential peak demand reduction in 2009 of about 30-40 MW.[49] Therefore, the referenced document is not materially different than information previously available.

The second document, ERCOT's "May 2010 Load Forecast and Reserve Margin Update" (May 18, 2010), was referenced by the Intervenors as part of Contention DEIS-1.[50] The Intervenors reference this document to attempt to demonstrate that the DEIS does not use updated load forecasts.[51] However, the data provided in ERCOT's May 2010 update is not significantly different from the information provided by ERCOT in May 2009,[52] which in turn is

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45 *See, e.g.*, *Private Fuel Storage, L.L.C.* (Independent Spent Fuel Storage Installation), LBP-98-7, 47 NRC 142, 208 (1998).

46 Power Comments at 2 n.3.

47 Motion at 3.

48 *See, e.g.*, San Antonio's Energy Future and You (STP Attachment 2), *available at* http://www.cpsenergy.com/Commercial/Rebates/Demand_Response/index.asp.

49 Nexant, Demand Side Management Potential Study, at 14 (Nov. 24, 2008) (STP Attachment 3), *available at* http://www.cpsenergy.com/files/Nexant_Market_Potential.pdf.

50 Power Comments at 2 n.5, 3-4.

51 Motion at 3-4; Power Comments at 2-4.

52 *See generally* ERCOT, Report on the Capacity, Demand, and Reserves in the ERCOT Region, System Planning (May 2009) (STP Attachment 4), *available at* http://www.ercot.com/content/news/presentations/2009/ERCOT%20CDR%202009%20with%208-3-09%20fuel%20type%20corrections.pdf.

referenced in the DEIS.[53] For example, the May 2010 update forecasts a reserve margin[54] of 13.5% in 2014,[55] whereas the May 2009 ERCOT report forecasts a reserve margin of 13.9% in 2014.[56] Therefore, the May 2010 ERCOT update predicts a slightly greater need for additional capacity than the May 2009 report. Furthermore, the reserve margin for 2014 forecast in the May 2010 update (13.5%) is substantially lower than the reserve margin for 2014 forecast in ERCOT's December 2008 update (15.8%).[57] Thus, the May 2010 update is not materially different (and in fact shows a greater need) than the information previously available.

The third document, "Climate Change Indicators in the United States" (April 2010), was referenced by the Intervenors as part of Contention DEIS-2.[58] The Intervenors rely upon this Environmental Protection Agency ("EPA") report for the conclusion that "compelling evidence that composition of the atmosphere and many fundamental measures of climate are changing" and to dispute the conclusions in DEIS Section 7.6.2 on the cumulative impacts from greenhouse gas emissions.[59] However, the information that was used to prepare the EPA report was previously available. For example, the EPA report was based upon a 2009 U.S. Global Change Research Program ("GCRP") report (which is cited in DEIS Section 7.6.2), along with a 2007

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53 DEIS at 8-16.

54 Reserve margin is defined as (Available Resources - Firm Load Forecast)/Firm Load Forecast. *Id.* at 8-14. ERCOT has a minimum required reserve margin of 12.5%. *See id.* at 8-15.

55 ERCOT, May 2010 Load Forecast and Reserve Margin Update, at 7 (May 18, 2010) (STP Attachment 5), *available at* http://www.ercot.com/calendar/2010/05/20100518-BOD. STP Attachment 5 appears to be identical to a May 18, 2010 ERCOT presentation filed by the Intervenors with their Motion, except for a slightly different 2014 reserve margin. STP Attachment 5 provides a 2014 reserve margin of 13.7% while the Intervenors' document provides a 2014 reserve margin of 13.5%. However, both of these values are less than the forecasted 2014 reserve margin in the May 2009 ERCOT report of 13.9%.

56 Report on the Capacity, Demand, and Reserves in the ERCOT Region, System Planning, at 8 (STP Attachment 4).

57 ERCOT, Report on the Capacity, Demand, and Reserves in the ERCOT Region, System Planning (Dec. 2008) (STP Attachment 6), *available at* http://www.ercot.com/content/news/presentations/2009/ERCOT_CDR_update_12-15-08_public.xls.

58 Motion at 5; Power Comments at 1, 8-9.

59 Motion at 5; Power Comments at 8-9.

Intergovernmental Panel on Climate Change ("IPCC") report.[60] Therefore, the information in the EPA report is not materially different than information previously available.

The fourth document, "Corpus Christi Council Gives City Manager Authority to Sell Water to Las Brisas Energy Center" (May 11, 2010), was referenced by the Intervenors as part of Contention DEIS-6.[61] The Intervenors rely upon this document in claiming that the DEIS evaluation of adequate surface water for STP Units 3 and 4 does not account for water used by the proposed Las Brisas power plant.[62] However, neither this proposed power plant nor its water consumption is new information. In fact, the same news outlet that generated the document referenced by the Intervenors has been discussing the Las Brisas plant for many months.[63]

In summary, even if the information cited by the Intervenors in these four documents is deemed "new," it clearly is not "materially different" from information that was previously available. As one licensing board explained, permitting any recent publication "reflecting information widely available previously, to be good cause for late filing would virtually wipe out the requirement of cause."[64] Because the information from these documents cited by the Intervenors is not materially different from information that was previously available, the Intervenors' citations to those documents do not satisfy 10 C.F.R. § 2.309(f)(2)(ii).

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60 EPA, Climate Change Indicators in the United States, at 68 (Apr. 2010) (STP Attachment 7) ("Assessment reports from the Intergovernmental Panel on Climate Change and the U.S. Global Change Research Program have linked many of these changes to increasing greenhouse gas emissions from human activities, which are also documented in this report."), *available at* http://www.epa.gov/climatechange/indicators/pdfs/CI-conclusion.pdf.

61 Power Comments at 11 n.32.

62 Motion at 10-11; Power Comments at 11-12.

63 *See, e.g.*, Corpus Christi City Council to Discuss Las Brisas Water Incentives (Mar. 26, 2010) (STP Attachment 8), *available at* http://www.caller.com/news/2010/mar/26/corpus-christi-city-council-to-discuss-las-water/; City Council to Begin Discussion on Garwood Pipeline (Dec. 7, 2009) (STP Attachment 9), *available at* http://www.caller.com/news/2009/dec/07/city-council-to-begin-discussion-on-garwood/.

64 *Cleveland Elec. Illuminating Co.* (Perry Nuclear Power Plant, Units 1 & 2), LBP-82-11, 15 NRC 348, 352 (1982) (noting that "the appearance of a newspaper article does not in and of itself create cause for late filing" under the criteria set forth in 10 C.F.R. § 2.309).

Additionally, the Power Comments do not constitute new information under the 10 C.F.R. § 2.309(f)(2)(ii) criterion. If an intervenor were allowed to use a document it prepared as a basis for satisfying 10 C.F.R. § 2.309(f)(2)(ii), the time limits for late-filed contentions would be meaningless, because an intervenor always could prepare a document and then use that document as a basis for tolling the time limits for a new contention. This is especially the case here, because Mr. Power is not an independent expert, but is the Deputy Director of Public Citizen, one of the Intervenors.[65] Under similar circumstances, the licensing board in the Bellefonte COL proceeding rejected a late-filed contention as untimely under 10 C.F.R. § 2.309(f)(2) notwithstanding the intervenors' claim that it was based on a new document that integrated older information into a single document for the first time.[66] That licensing board stated that this repackaged information's "status as 'materially different' for the purpose of interposing timely a new contention in this proceeding is problematic."[67] For this same reason, the Power Comments do not satisfy the timeliness requirements of 10 C.F.R. § 2.309(f)(2).

In summary, the DEIS contentions do not satisfy 10 C.F.R. § 2.309(f)(2). As a result, the Intervenors must satisfy 10 C.F.R. § 2.309(c). As discussed below, the Intervenors have not satisfied that regulation either.

D. The New Contentions Do Not Satisfy the Requirements for Nontimely Contentions

Given that the Intervenors have not satisfied the criteria in 10 C.F.R. § 2.309(f)(2), they must satisfy the test set forth in 10 C.F.R. § 2.309(c)(1) related to "nontimely" contentions. The burden is on the Intervenors to demonstrate "that a balancing of these factors [in 10 C.F.R. §

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65 *See* Texas Staff Members Bio's (STP Attachment 10) (undated), *available at* http://www.citizen.org/texas/about/articles.cfm?ID=11450.

66 *Tenn. Valley Auth.* (Bellefonte Nuclear Power Plant Units 3 & 4), at 6 (Apr. 29, 2009) (Licensing Board Memorandum and Order (Ruling on Request to Admit New Contention)) (unpublished), *available at* ADAMS Accession No. ML091190393.

67 *Id.* at 8.

2.309(c)(1)] weighs in favor of granting the petition."[68] The factors in 10 C.F.R. § 2.309(c)(1) are not of equal importance: absence of good cause (factor one) and the likelihood of substantial broadening of the issues and delay of the proceeding (factor seven) are the most significant.[69] Factors five (availability of other means) and six (interests represented by other parties) are entitled to the least weight.[70]

Turning to the first factor, the Intervenors have not identified, much less demonstrated, good cause for failure to file the new contentions on time. To demonstrate good cause, a petitioner must show not only that it "acted promptly after learning of the new information, but the information itself must be *new* information, not information already in the public domain."[71] As discussed in detail above, the new contentions do not provide any new information and the Intervenors were not prevented from filing these contentions much earlier. In fact, as discussed above, the Intervenors filed similar contentions in their original Petition, and these contentions were rejected by the Board.

The Commission has stated that "[l]acking a favorable showing on good cause, a petitioner must show a compelling case on the remaining [applicable] factors."[72] Factors two through four speak towards standing. Therefore, their applicability is limited here because the Intervenors are already parties to this proceeding and are seeking admission of nontimely contentions, rather than nontimely intervention. There are other means for the Intervenors to protect their interests under the fifth factor - - namely, the Intervenors can submit comments on

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68 *Tex. Utils. Elec. Co.* (Comanche Peak Steam Electric Station, Units 1 & 2), CLI-88-12, 28 NRC 605, 609 (1988).

69 *See, e.g.*, *Project Mgmt. Corp.* (Clinch River Breeder Reactor Plant), ALAB-354, 4 NRC 383, 395 (1976).

70 *See Private Fuel Storage, L.L.C.* (Independent Spent Fuel Storage Installation), LBP-00-8, 51 NRC 146, 154 (2000) (citing *Commonwealth Edison Co.* (Braidwood Nuclear Power Station, Units 1 & 2), CLI-86-8, 23 NRC 241, 244-45 (1986)).

71 *Tex. Utils. Elec. Co.* (Comanche Peak Steam Electric Station, Units 1 & 2), CLI-92-12, 36 NRC 62, 70 (1992).

72 *State of New Jersey*, CLI-93-25, 38 NRC at 296.

the DEIS.[73] In accordance with 10 C.F.R. § 51.91(a)(1), the FEIS must address any comments. Under the sixth factor in 10 C.F.R. § 2.309(c), there are no other parties in this proceeding that will represent the Intervenors' interests. Thus, only the seventh and eighth factors remain to be evaluated.

The seventh factor (*i.e.*, the extent to which the participation will broaden the issues or delay the proceeding) weighs against the new contentions. The new contentions would broaden the issues in this proceeding because they raise topics that are different from the currently admitted contentions. Furthermore, STPNOC has submitted motions that if granted would result in the dismissal of all of the currently admitted contentions and would obviate the need for a contested hearing. Thus, admitting the new contentions at this late date could delay this proceeding considerably by requiring an otherwise unnecessary contested hearing.

The eighth factor (*i.e.*, extent to which the petitioner's participation may reasonably be expected to assist in developing a sound record) also weighs against the new contentions. As the Commission has stated, to make a showing on this factor, an intervenor should specify the precise issues it plans to cover, identify its prospective witnesses, and summarize their proposed testimony.[74] The Intervenors have failed to do so, and otherwise have failed to identify how they would assist in developing a sound record. In this regard, the contentions and the Power Comments essentially consist of references to documents and reports prepared by others, without any expert analysis. As another licensing board explained in holding this factor against an intervenor, "[the intervenor] has done little more than point to the two affiants supporting the

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[73] *See* STP Nuclear Operating Company; Notice of Availability of the Draft Environmental Impact Statement for Combined Licenses for Units 3 and 4 at the South Texas Project Site, 75 Fed. Reg. 14,474 (Mar. 25, 2010). In fact, representatives of the Intervenors already have provided comments on the DEIS. *See, e.g.*, Transcript of "Draft EIS for South Texas Project Public Meeting: Afternoon Session," at 42-47 (comments of Tom Smith of Public Citizen), 48-52 (comments of Karen Hadden of SEED), 67-74 (comments of Susan Dancer) (May 6, 2010) (STP Attachment 25), *available at* ADAMS Accession No. ML101450282.

[74] *Braidwood*, CLI-86-8, 23 NRC at 246.

contention, without providing any real clue about what they would say to support the contention beyond the minimal information they provide for admitting the contention."[75] Thus, based upon the contentions themselves, it is not evident that the Intervenors would be able to assist in developing a sound record.

In summary, weighing the factors in 10 C.F.R. § 2.309(c) demonstrates that the new contentions should be rejected. Accordingly, the Motion should be denied.

V. THE NEW CONTENTIONS DO NOT SATISFY THE CONTENTION ADMISSIBILITY REQUIREMENTS IN 10 C.F.R. § 2.309(f)(1)

As discussed above, none of the new contentions satisfies the requirements in 10 C.F.R. §§ 2.309(c) or (f)(2), and therefore the contentions should be rejected for that reason alone. In addition, the new contentions do not satisfy the contention admissibility requirements in 10 C.F.R. § 2.309(f)(1). This failure provides an independent reason for rejecting all of the new contentions.

A. Contention DEIS-1 - - Need for Power

Contention DEIS-1 states:

> The DEIS analysis of the need for power is flawed and incomplete.[76]

The Intervenors claim that the need for power analysis in the DEIS fails to address a variety of topics that if considered would reduce or eliminate the need for power from STP Units 3 and 4.[77] As demonstrated below, Contention DEIS-1 is not admissible because the information it cites is not material and does not demonstrate a genuine dispute of material fact.

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75 *Private Fuel Storage*, LBP-98-7, 47 NRC at 208-09.

76 Motion at 2.

77 *Id.* at 2-5.

The need for power from STP Units 3 and 4 is addressed in DEIS Chapter 8: Section 8.1 describes the power system, Section 8.2 discusses power demand, Section 8.3 discusses power supply, and Section 8.4 assesses the need for power. The DEIS concludes that there would be a need for 4,400 MW of baseload generation in 2019.[78] This value increases greatly to 10,417 MW in 2024.[79] Additionally, the DEIS states: "Based on its analysis, the review team concludes that there is a justified need for new baseload generating capacity in the ERCOT region in excess of the planned 2740 MW capacity output of proposed Units 3 and 4 at STP."[80]

The evaluation of need for power in the DEIS is based upon studies prepared by ERCOT.[81] ERCOT is the independent system operator ("ISO") for the electrical grid for most of Texas. ERCOT is assigned by state law with responsibility for central planning and analysis of the resources needed for the electrical system in the ERCOT region.[82] Before relying upon the ERCOT forecasts, the NRC Staff reviewed the ERCOT studies and concluded that they are systematic, comprehensive, subject to confirmation, and responsive to forecasting uncertainty.[83]

Contention DEIS-1 does not provide or reference any new demand forecasts that are materially different than the DEIS analysis or the studies by ERCOT referenced in the DEIS. Instead, this contention 1) is based upon an ERCOT updated forecast in May 2010 that is not materially different than the ERCOT studies cited in the DEIS; and 2) raises the possibility that future events might occur that could affect the results of the DEIS analysis, such as possible changes in legislation, possible increases in conservation and energy efficiency, possible new

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78 DEIS at 8-25.

79 *Id.* at 8-23.

80 *Id.* at 8-26.

81 *Id.* at 8-5 to 8-7.

82 *Id.* at 8-3 to 8-4.

83 *Id.* at 8-7.

generating plants, and the like. However, in so arguing, this contention essentially ignores a long-established set of NRC cases governing need for power analyses.

By way of background, the NRC Staff is entitled to rely upon studies and forecasts prepared by an independent body that is charged by state law with making forecasts of power demand, such as ERCOT. As discussed in detail by the Appeal Board in the *Shearon Harris* decision, such forecasts are entitled to "great weight" absent "some fundamental error" in their analyses.[84] As the Appeal Board explained:

> But where a utilities commission forecast is neither shown nor appears on its face to be seriously defective, no abdication of NRC responsibilities results from according conclusive effect to that forecast. Put another way, although the National Environmental Policy Act mandates that this Commission satisfy itself that the power to be generated by the nuclear facility under consideration will be needed, we do not read that statute as foreclosing the placement of heavy reliance upon the judgment of local regulatory bodies which are charged with the duty of insuring that the utilities within their jurisdiction fulfill the legal obligation to meet customer demands.[85]

In this proceeding, the Intervenors have not alleged, let alone provided any basis for a claim, that the ERCOT studies have a "fundamental error" or are "seriously defective." To the contrary, the Intervenors favorably cite to ERCOT's May 2010 update of its load forecast and reserve margin calculation.[86] Therefore, to the extent that Contention DEIS-1 is based upon analyses or factors that are different than those in the ERCOT studies, it should be rejected because it does not provide a legally sufficient basis for challenging the need for power analysis in the DEIS, which is based upon the ERCOT studies.

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84 *Carolina Power & Light Co.* (Shearon Harris Nuclear Power Plant, Units 1, 2, 3, & 4), ALAB-490, 8 NRC 234, 240 (1979).

85 *Id.* at 241.

86 Motion at 3.

Furthermore, the Intervenors' recitation of uncertainties that might affect future demand does not provide a sufficient basis for challenging the need for power analysis in the DEIS. In the leading case, *Niagara Mohawk Power Corp.* (Nine Mile Point Nuclear Station, Unit 2), ALAB-264, 1 NRC 347, 365-67 (1975), the Appeal Board held that "inherent in any forecast of future electric power demands is a substantial margin of uncertainty," and therefore the projection of future need should be accepted if it is "reasonable." As the Appeal Board held in a later case:

> [A] forecast that such need exists is not to be discarded as fatally flawed simply because the future course of events is sufficiently clouded to give rise to the possibility of a significant margin of error. Given the legal responsibility imposed upon a public utility to provide at all times adequate, reliable service – and the severe consequences which may attend upon a failure to discharge that responsibility – the most that can be required is that the forecast be a reasonable one in the light of what is ascertainable at the time made.[87]

This standard has been endorsed by the Commission. In *Carolina Power and Light Co.*, the Commission stated:

> The Nine Mile Point rule recognizes that every prediction has associated uncertainty and that long-range forecasts of this type are especially uncertain in that they are affected by trends in usage, increasing rates, demographic changes, industrial growth or decline, the general state of the economy, etc. These factors exist even beyond the uncertainty that inheres to demand forecasts: assumptions on continued use from historical data, range of years considered, the area considered, extrapolations from usage in residential, commercial, and industrial sectors, etc.[88]

Similarly, the Appeal Board in *Duke Power Co.* (Catawba Nuclear Station, Units 1 and 2), ALAB-355, 4 NRC 397, 410 (1976), ruled that load forecasts

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[87] *Kan. Gas & Elec. Co.* (Wolf Creek Generating Station, Unit No. 1), ALAB-462, 7 NRC 320, 328 (1978).

[88] *Carolina Power & Light Co.* (Shearon Harris Nuclear Power Plant, Units 1, 2, 3, & 4), CLI-79-5, 9 NRC 607, 609-10 (1979).

> are [not] automatically suspect because they are inclined to be "conservative," that is to say they tend to project future loads closer to the high than to the low end of the demand spectrum. To be sure, if demand does turn out to be less than predicted it can be argued (as intervenor does) that the cost of the unneeded generating capacity may turn up in the customers' electric bills. . . . But should the opposite occur and demand outstrip capacity, the consequences are far more serious.

In contrast to this well-settled line of cases, this contention essentially argues that there is uncertainty in the DEIS forecasts because future conditions might be different than current conditions. However, as the above cases have held, such uncertainty is inherent in demand forecasts, and is not a sufficient legal basis for rejecting the forecasts. Since this contention does not provide any basis for believing that the DEIS forecasts are unreasonable, it does not raise a material issue and the contention should be rejected.

Additionally, contrary to 10 C.F.R. § 2.309(f)(1)(ii) and (v), the Intervenors have not provided any basis or adequate support for many of their statements in this contention. Instead, much of the contention engages in speculation. For example,

- The Intervenors state that the DEIS need for power analysis is incomplete because it only accounts for reduced demand from DSM due to Texas House Bill 3693, but it does not account for reduced demand from DSM due to U.S. House of Representatives Bill 5019 ("HR 5019").[89] HR 5019, however, currently is pending before the U.S. Senate and has not been enacted into law.[90] As the licensing board ruled in the *Bellefonte* proceeding, potential legislative action that might result in a reduction in demand is speculative and therefore does not provide a basis for admission of a contention on need for power.[91]

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[89] Motion at 2-3; Power Comments at 6.

[90] *See* Summary of HR 5019 (STP Attachment 11), *available at* http://thomas.loc.gov/cgi-bin/bdquery/z?d111:HR05019:@@@L&summ2=m&.

[91] *Tenn. Valley Auth.* (Bellefonte Nuclear Power Plant, Units 3 & 4), LBP-08-16, 68 NRC 361, 410 (2008).

- The Power Comments state that a new study is being performed to revise calculations regarding the capacity factor of wind in the ERCOT market.[92] However, as the licensing board recently ruled in *Vogtle* in rejecting a similar contention, "[t]he fact that a new analysis is being prepared, taken alone, does not provide support for the claim that the [need for power] analysis in the ER is flawed."[93]
- The Intervenors state that the "DEIS does not account for a non-wind renewable capacity mandate under consideration by the Texas PUC" that they believe would add 500 MW of capacity in the ERCOT region.[94] The rulemaking corresponding to this mandate, however, has not been completed and it is speculation as to whether it will be completed.[95] Therefore, based upon the *Bellefonte* decision discussed above, this argument is also insufficient to support a contention related to the need for power.
- The Intervenors state that the "DEIS does not account for a compressed air energy storage (CAES) project planned for Texas by ConocoPhillips/General Compression that will be available for baseload capacity."[96] Based on the document referenced by the Intervenors, this CAES project is only a "pilot project."[97] It is speculative whether this plant will ever be constructed and operated, let alone make a material difference to the need for power analysis by ERCOT.

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92 Power Comments at 3 n.6.

93 *S. Nuclear Operating Co.* (Early Site Permit for Vogtle ESP Site), LBP-07-3, 65 NRC 237, 272 (2007); *see also Bellefonte*, LBP-08-16, 68 NRC at 410-11.

94 Motion at 4.

95 *See, e.g.*, Rulemaking to Relating to the Goal for Renewable Energy, Project # 35792 (last updated June 4, 2010) (STP Attachment 12), *available at* http://www.puc.state.tx.us/rules/rulemake/35792/35792.cfm.

96 Motion at 5.

97 PrairieGold Venture Partners, General Compression Signs Agreement with ConocoPhillips to Develop CAES Projects (Apr. 14, 2010) (STP Attachment 14), *available at* http://www.pgvp.com/news/index.php?newsid=15.

As the Commission has previously stated, a contention is inadmissible if it only offers "bare assertions and speculation."[98] Since the above statements by the Intervenors run afoul of the Commission's admonition, they do not support this contention.

Somewhat similarly, the Intervenors state that the "DEIS does not account for 31,757 MW of additional capacity through interconnections in the ERCOT region by 2015."[99] The 31,757 MW in question is not additional capacity that is currently available through interconnections; instead, as explained in the ERCOT documents, it is the combination of mothballed capacity (5,022 MW), 50% of non-synchronous ties (553 MW), and planned units in the Full Interconnection Study Phase (26,182 MW).[100] The largest portion of this capacity, planned units in Full Interconnection Study Phase, are units that are part of studies to determine the effects of adding the new generation to the transmission system.[101] This capacity does not currently exist, is not currently available to supply power to the ERCOT region, and is not accounted for in the ERCOT forecasts.[102] At this stage, it is speculation as to whether these units will be constructed and will be available for generation in the ERCOT region. ERCOT does not consider such units to be an available resource. As ERCOT has explained:

> [T]here is much uncertainty associated with many of the proposed interconnections. One reason is that multiple interconnection requests may be submitted representing alternative sites for one

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98 *Fansteel Inc.* (Muskogee, Oklahoma Site), CLI-03-13, 58 NRC 195, 203 (2003) (quoting *GPU Nuclear, Inc.* (Oyster Creek Nuclear Generating Station), CLI-00-6, 51 NRC 193, 208 (2000)).

99 Motion at 4.

100 May 2010 Load Forecast and Reserve Margin Update, at 7 (STP Attachment 5).

101 ERCOT, Report on the Capacity, Demand, and Reserves in the ERCOT Region, at 7 (May 2010) (STP Attachment 15), *available at* http://www.ercot.com/content/news/presentations/2010/2010%20Capacity,%20Demand%20and%20Reserves.pdf.

102 *See id.*

> proposed facility. For this and other reasons, it is possible that much of this capacity will not be built.[103]

Instead, ERCOT only considers those planned plants that have a signed generation interconnection agreement ("SGIA") as an available resource in its calculation of reserve margin.[104] Because the Intervenors' approach is inconsistent with ERCOT's approach, and because the Intervenors have not demonstrated any fundamental error in ERCOT's approach, the Intervenors' arguments related to possible future interconnections to the grid should be rejected in accordance with the precedent in *Shearon Harris* discussed above.

Furthermore, contrary to 10 C.F.R. § 2.309(f)(1)(iv) and (vi), the issues raised by the contention are not material to the need for power and do not demonstrate a genuine dispute of material fact or law. In general, the contention consists of nothing more than a string of statements alleging that the DEIS should have considered a particular issue in its need for power analysis, without any demonstration that such a consideration would materially affect the results of the analysis. For example:

- The Intervenors claim that the DEIS need for power analysis is incomplete because it does not account for reduced demand due to HR 5019.[105] The Intervenors, however, have not alleged, let alone demonstrated, that HR 5019 would materially reduce demand in Texas or change the need for power evaluation in the DEIS if it were enacted.
- The Intervenors claim that the "DEIS does not address the recent energy efficiency experiences of the San Antonio municipal utility that yielded a peak reduction of 44.7

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103 ERCOT, Report on Existing and Potential Electric System Constraints and Needs, at 26 (Dec. 2009) (STP Attachment 13), *available at* http://www.ercot.com/content/news/presentations/2010/2009_Constraints_and_Needs_Report_21DEC2009.pdf.

104 *See* DEIS at 8-14.

105 Motion at 2-3; Power Comments at 6.

MW."[106] The DEIS, however, concludes that there would be a need for 4,400 MW of baseload power in the ERCOT region in 2019.[107] Even if this value were reduced by 44.7 MW, there would still be a need for the 2,740 MW STP Units 3 and 4. Therefore, the Intervenors' argument is not material.[108]

- The Intervenors claim that the "DEIS analysis of the need for power is flawed because it does not consider the most recent energy forecast from ERCOT" in a May 2010 update.[109] In particular, the Intervenors state that the recent energy forecast reduces the peak demand in 2015 from 72,172 MW to 70,517 MW (1,655 MW decrease).[110] However, the Intervenors have selectively cited from the May 2010 update. In particular, the Intervenors have ignored the reduction in the total generation resources that are identified in the May 2010 update that would offset the effect of the reduced demand on the need for power. Specifically, the update referenced by the Intervenors identifies total resources in 2015 of 77,543 MW,[111] while the earlier projection was 78,017 MW.[112] Additionally, as discussed in Section IV.C above, the May 2010 update actually predicts a lower reserve margin in 2014 than the DEIS. Thus, when the May 2010 update is considered as a whole, it indicates an *increase* in need for additional power.

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106 Motion at 3; Power Comments at 2.

107 DEIS at 8-25.

108 Additionally, the DEIS already assumes a reduction in demand due to energy efficiency of 110 MW and 242 MW in 2009 and 2010, respectively, which is greater than the 44.7 MW identified by the Intervenors. *Id.* at 8-16.

109 Motion at 3.

110 *Id.*

111 May 2010 Load Forecast and Reserve Margin Update, at 7 (STP Attachment 5).

112 ERCOT, Report on the Capacity, Demand and Reserves in the ERCOT Region, at 4 (Dec. 2009) (STP Attachment 16), *available at* http://www.ercot.com/content/news/presentations/2010/2009CDR_DecUpdate.pdf.

- Similarly, the Intervenors claim that based on the May 2010 ERCOT update the "DEIS fails to account for the addition of 2,073 MW of non-nuclear capacity to the ERCOT generation portfolio."[113] The Intervenors, however, are selectively using information from the ERCOT update. The update demonstrates that the net effect of this new generation (2,073 MW) when combined with cancelled generation projects (-48 MW), mothballed units (-2,053 MW), and other changes (-446 MW) results in a 474 MW net *reduction* in power supply.[114] This power supply reduction actually increases the need for power in the ERCOT region.
- The Intervenors claim that the "DEIS analysis does not account for increases in wind carrying capacity."[115] In particular, the Intervenors state that the recent energy forecast increases the wind carrying capacity from 708 MW to 793 MW (85 MW increase) with another 115 MW increase by 2015.[116] The DEIS, however, concludes that there would be a need for 4,400 MW of baseload power in the ERCOT region in 2019.[117] Even if this value were reduced by 200 MW (85 MW + 115 MW), there would still be a need for the 2,740 MW STP Units 3 and 4.
- The Intervenors state that the "DEIS does not account for reduced demand caused by the adoption of the International Energy Conservation Code" that they believe would reduce peak demand by 2,362 MW annually by 2023 in the ERCOT region.[118] The DEIS concludes, however, that there would be a need for an additional 10,417 MW of baseload

113 Motion at 3.

114 May 2010 Load Forecast and Reserve Margin Update, at 4 (STP Attachment 5).

115 Motion at 3.

116 *Id.*

117 DEIS at 8-25.

118 Motion at 4.

power in the ERCOT region in 2024.[119] Even if this value were reduced by 2,362 MW, there would still be a need for the 2,740 MW STP Units 3 and 4.

As has been previously held by the Commission, "[t]he dispute at issue is 'material' if its resolution would 'make a difference in the outcome of the licensing proceeding.'"[120] The contention runs afoul of this requirement, and should be rejected.

Finally, this contention repeats arguments in Contention 26 that were already rejected by the Board. Similar to Contention DEIS-1, Contention 26 alleged that the need for power analysis is deficient because it did not address various factors, such as a decrease in demand, increased energy efficiency, and increased renewable energy sources.[121] The Board rejected Contention 26 because it failed to demonstrate a genuine dispute.[122] Contention DEIS-1 should be rejected for the same reason.

In summary, this contention consists of nothing more than speculation, use of approaches that are inconsistent with the approaches used by ERCOT, selective extractions of information from the May 2010 ERCOT update, and arguments related to issues that do not affect the conclusions of the need for power analysis. For the foregoing reasons, this contention is immaterial and does not demonstrate that a genuine dispute exists. Therefore, the Board should reject this contention.

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119 DEIS at 8-23.

120 *Oconee*, CLI-99-11, 49 NRC at 333-34 (citing Final Rule, Rules of Practice for Domestic Licensing Proceedings – Procedural Changes in the Hearing Process, 54 Fed. Reg. 33,168, 33,172 (Aug. 11, 1989)).

121 *South Texas Project*, LBP-09-21, slip op. at 52-53.

122 *Id.* at 55-56.

B. <u>Contention DEIS-2 - - Global Warming</u>

Contention DEIS-2 states:

> The DEIS understates the effect of global warming on the cumulative impacts of the operation of STP 3 & 4.[123]

The Intervenors claim that the DEIS fails to account for a recent EPA report, does not consider the impacts on plant operation from increases in salinity of the Colorado River, fails to compare cumulative impacts to surface water quality from alternatives such as wind and solar, and fails to address cooling water availability due to impacts from global warming.[124] As demonstrated below, Contention DEIS-2 is not admissible because it is not material, it is not adequately supported, and it does not demonstrate a genuine dispute of material fact.

1. EPA Report

The Intervenors first claim that the "DEIS conclusion that cumulative effects of greenhouse gas emissions are projected to be 'noticeable but not destabilizing' is contradicted by the EPA's April 27, 2010 report 'Climate Change Indicators in the United States'."[125] However, as discussed below, the Intervenors' claims are not material.

DEIS Section 7.6.2 evaluates the cumulative impacts of greenhouse gas emissions, and concludes:

> Evaluation of cumulative impacts of greenhouse gas emissions requires the use of a global climate model. The GCRP report referenced above provides a synthesis of the results of numerous climate modeling studies. The review team concludes that the cumulative impacts of greenhouse emissions around the world as presented in the report are the appropriate basis for its evaluation

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123 Motion at 5.

124 *Id.* at 5-6.

125 *Id.* at 5 (citations omitted). The Intervenors also state that "[a] full accounting for all stages of the [uranium fuel cycle] shows that nuclear power has significantly greater GHG burdens than wind, solar power or geothermal." *Id.* at 5-6. That same claim is made in the context of Contention DEIS-3 and is discussed further below.

> of cumulative impacts. Based on the impacts set forth in the GCRP report, the review team concludes that the national and worldwide cumulative impacts of greenhouse gas emissions are noticeable but not destabilizing. *The review team further concludes that the cumulative impacts would be noticeable but not destabilizing, with or without the greenhouse gas emissions of the proposed project*.[126]

DEIS Section 7.6.3 further states: "The review team concludes that cumulative impacts from other past, present, and reasonably foreseeable future actions on air quality resources in the geographic areas of interest would be MODERATE. *The incremental contribution of impacts on air quality resources from building and operating proposed Units 3 and 4 would be SMALL*."[127]

As discussed above, the GCRP report referenced in the DEIS is the basis for the greenhouse gas information in the EPA report referenced by the Intervenors.[128] The Intervenors' dispute appears to be limited to the Staff's characterization of the cumulative impacts as "not destabilizing." In essence, the Intervenors are quibbling over the choice of words in the DEIS rather than the nature of the impacts referenced in the DEIS. In this regard, as the Commission has noted, "[o]ur boards do not sit to 'flyspeck' environmental documents or to add details or nuances."[129] This aspect of Contention DEIS-2 should be rejected for this reason alone.

Furthermore, this dispute over characterization of the cumulative impacts is not material, because it does not relate to the impacts from STP Units 3 and 4. As the DEIS makes clear, the greenhouse gas emissions from the uranium fuel cycle for a nuclear power plant are less than 0.00002 of the global greenhouse gas emissions (400,000 metric tons versus 28,000,000,000

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126 DEIS at 7-44 (emphasis added).

127 *Id.* at 7-45 (emphasis added).

128 Climate Change Indicators in the United States, at 68 (STP Attachment 7) ("Assessment reports from the Intergovernmental Panel on Climate Change and the U.S. Global Change Research Program have linked many of these changes to increasing greenhouse gas emissions from human activities, which are also documented in this report.").

129 *Sys. Energy Res., Inc.* (Early Site Permit for Grand Gulf ESP Site), CLI-05-4, 61 NRC 10, 13 (2005).

metric tons per year), and therefore do not affect the cumulative impacts of greenhouse gas emissions.[130] The Intervenors have not disputed that STP Units 3 and 4 will make an insignificant contribution to the cumulative greenhouse gas emissions. Since this proceeding pertains to STP Units 3 and 4 and not to climate change in general, the Intervenors' arguments regarding the impacts of greenhouse gas emissions on global climate change are immaterial.

In summary, even if the Intervenors' characterization of the impacts of greenhouse gases on climate change were to be accepted, it would not affect the conclusions in the DEIS that STP Units 3 and 4 would not make a noticeable contribution to such changes. As has been previously held by the Commission, a "dispute at issue is 'material' if its resolution would 'make a difference in the outcome of the licensing proceeding.'"[131] Therefore, the Intervenors' argument does not raise a material issue nor demonstrate a genuine dispute of material fact, contrary to 10 C.F.R. § 2.309(f)(1)(iv) and (vi).

2. Increases in Salinity of Cooling Water

The Intervenors state that the "DEIS acknowledges that a rising sea level caused by climate change could cause salt water to flow farther up the Colorado River towards the Reservoir Makeup Pumping Facility but does not consider the increased salinity of the water on plant operations."[132]

This argument regarding water salinity does not demonstrate a genuine dispute of material fact. The Intervenors provide no basis for arguing that the plant would withdraw any appreciable amounts of salt water from the Colorado River. As explained in DEIS Section 5.2.2.1, STPNOC is only allowed to withdraw water from the Colorado River when its flow

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130 DEIS at 7-44.

131 *Oconee*, CLI-99-11, 49 NRC at 333-34 (citing Final Rule, Rules of Practice for Domestic Licensing Proceedings – Procedural Changes in the Hearing Process, 54 Fed. Reg. at 33,172).

132 Motion at 6.

exceeds 300 cfs.[133] Additionally, as discussed in the DEIS, withdrawal of makeup water from the Colorado River is limited based on the specific conductivity of the water,[134] which serves to prevent intake of salt water and maintain reservoir water quality. Furthermore, if necessary during drought conditions, the Lower Colorado River Authority ("LCRA") would release upstream fresh water for makeup to the Main Cooling Reservoir ("MCR").[135] These actions ensure that makeup water is high quality and does not have excessive salinity.

In any event, there is no dispute of material fact that salinity in the cooling water would not affect operation of STP Units 3 and 4. The Final Safety Analysis Report ("FSAR") for STP Units 3 and 4 explains that the "[m]aterials selected for the [Circulating Water System] are those that withstand long-term corrosion."[136] For example, the ER explains that the condenser will use titanium or stainless steel tubes that would be resistant to corrosion from salt water.[137] In contrast, the basis for Intervenors' allegation is Information Notice 84-71, which involved corrosion of cast iron and therefore is not relevant.[138]

In summary, there was no reason for the DEIS to discuss the impacts on operation from increases in salinity in the Colorado River, because the withdrawals of water from the River are managed and limited to ensure that the water is of high quality, and the plant is designed with material that is resistant to salt water corrosion. Therefore, the Intervenors' arguments do not

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133 DEIS at 5-7.

134 *Id.* at 5-7 to 5-8.

135 *Id.*

136 FSAR at 10.4-9 (Rev. 3), *available at* ADAMS Accession No. ML092931376.

137 ER at 3.2-2 (Rev. 3), *available at* ADAMS Accession No. ML092931546.

138 Motion at 6 n.19. The Intervenors' other reference in footnote 19 pertains to cooling towers, and includes the statement that components exposed to salt water should be made of stainless steel, and that "stainless steel resists salt water very well in areas which are highly aerated." John A. Nelson, Cooling Towers & Salt Water, at 2 (Nov. 5, 1986) (STP Attachment 26), *available at* http://spxcooling.com/pdf/CTs-and-Salt-Water.pdf. This reference cuts against the Intervenors' argument.

raise a genuine dispute of material fact, and their arguments should be rejected pursuant to 10 C.F.R. § 2.309(f)(1)(vi).

3. Comparison of Cumulative Impacts of Global Warming with Alternatives

The Intervenors claim that the "DEIS describes STP 3 & 4 cumulative impacts on surface water and groundwater quality but fails to compare cumulative impacts to surface water quality from alternatives such as wind and solar."[139] The DEIS does not compare surface water and groundwater quality of STP Units 3 and 4 to wind and solar because the DEIS determined that these alternatives do not meet the need for baseload power generation.[140] An EIS is not required to evaluate the environmental impacts of alternatives if those alternatives are determined to not be feasible means of accomplishing the purpose of a project.[141]

For this reason, this argument in Contention DEIS-2 does not raise a material issue, contrary to 10 C.F.R. § 2.309(f)(1)(iv), and does not identify a genuine dispute with the DEIS, contrary to 10 C.F.R. § 2.309(f)(1)(vi). Accordingly, it should be rejected.

4. Cooling Water Availability

The Intervenors claim that the "DEIS fails to consider the effect of global warming on operations of STP Units 3 & 4 related to 1) water availability and 2) increased ambient temperatures of air and the effect of higher cooling water temperatures."[142] These arguments about cooling water availability fail for multiple reasons.

Contrary to the Intervenors' claims, the DEIS does consider the impacts of global warming on water availability and cooling water temperatures. For example, the DEIS states that, within the Colorado River Basin during the licensed lifetime of STP Units 3 and 4,

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139 Motion at 6 (citation omitted).

140 DEIS at 9-31.

141 *See Clinton ESP*, CLI-05-29, 62 NRC at 808.

142 Motion at 6.

temperatures could increase 0^{o} to 5^{o}F, and precipitation could decline 10 to 30 percent relative to 1961-1979.[143] The DEIS further states that "[t]he review team determined that the forecasted changes [from climate change] could affect water supply and water quality in the Colorado River Basin during operation of the proposed STP Units 3 and 4."[144] DEIS Section 7.2.1.1 evaluates those impacts from global warming relative to its evaluation in DEIS Section 5.2, which concluded that the surface water impacts of operation would be SMALL. The DEIS evaluates the cumulative water uses in the region (including STP), and states that "water demand in 2060 can be met."[145] DEIS Section 7.2.1.1 concludes that "[w]hile these changes from [global climate change] may not be insignificant, the review team has not identified anything that would alter the conclusions presented above."[146] Therefore, the DEIS concluded that global warming impacts would not impact the other conclusions in DEIS Section 5.2, which includes conclusions on cooling water availability. For this reason, the Intervenors have not demonstrated a genuine dispute of material fact, contrary to 10 C.F.R. § 2.309(f)(1)(vi).

With respect to water temperature, the Intervenors' arguments do not raise any genuine dispute of material fact. The Intervenors refer to situations in which nuclear and coal plants have been forced to shut down due to high water temperatures. However, those situations involved cases in which the plants discharged to natural bodies of water and needed to shut down due to thermal limits established for environmental protection.[147] In contrast, STPNOC discharges into the MCR, which is an artificial water body dedicated to cooling of STP units. STPNOC's Texas Pollutant Discharge Elimination System ("TPDES") permit does not limit the temperature of

143 DEIS at 7-9.

144 *Id.*

145 *Id.* at 7-12.

146 *Id.* at 7-13.

147 Power Comments at 10-11.

discharges to the MCR.[148] However, with four units operating, STPNOC may need to discharge water from the MCR to the Colorado River once every 11 days,[149] and the TPDES permit does limit the temperature of discharges from the MCR to the Colorado River to an average of 95^{o}F.[150] As shown in DEIS Table 5-3,[151] the median MCR water temperature is predicted to be approximately 75^{o}F and the 90th percentile temperature is predicted to be less than 90^{o}F with all four units operating. Therefore, even with the predicted increases in air temperatures of 0^{o} to 5^{o}F due to global warming, there should be little or no impact on STPNOC's ability to discharge from the MCR to the Colorado River due to water temperatures. Accordingly, there was no reason for the DEIS to discuss this issue. In this regard, an "agency's environmental review, rather than addressing every impact that could possibly result, need only account for those that have some likelihood of occurring or are reasonably foreseeable."[152] Consideration of "inconsequentially small" impacts is not required.[153]

Moreover, the Intervenors' arguments regarding impacts to plant operations do not raise a litigable environmental issue and therefore do not demonstrate a genuine dispute of law, contrary to 10 C.F.R. § 2.309(f)(1)(vi). In this regard, one licensing board rejected similar arguments about the uncertainties of future cooling water supplies, stating that "[i]nsofar as environmental matters are concerned, under the National Environmental Policy Act (NEPA) there is no legal basis for refusing [the applicant] its operating license merely because some environmental

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148 *See* TPDES Permit No. WO0001908000 (July 21, 2005) ("TPDES Permit") (STP Attachment 17), *available at* ADAMS Accession No. ML052230202.

149 DEIS at 5-18.

150 *See* TPDES Permit at 2 (STP Attachment 17) (with respect to Outfall 001).

151 DEIS at 5-16.

152 *La. Energy Servs., L.P.* (National Enrichment Facility), LBP-06-8, 63 NRC 241, 258-59 (2006) (citing *Long Island Lighting Co.* (Shoreham Nuclear Power Station), ALAB-156, 6 AEC 831, 836 (1973)).

153 *See Vt. Yankee Nuclear Power Corp.* (Vermont Yankee Nuclear Power Station), ALAB-919, 30 NRC 29, 44 (1989) (citing *Limerick Ecology Action v. NRC*, 869 F.2d 719, 739 (3d Cir. 1989)).

uncertainties may exist in [the applicant's] future coolant supply," including an inability to operate the plant 100% of the time due to temporary water shortages.[154]

Finally, this contention repeats arguments in Contention 11 that were already rejected by the Board. Similar to Contention DEIS-2, Contention 11 alleged that the application did not adequately consider the impacts of global warming on plant operations, including water availability.[155] The Board rejected Contention 11 because it failed to provide adequate support or demonstrate a genuine dispute.[156] Contention DEIS-2 should be rejected for the same reasons.

C. Contention DEIS-3 - - Comparison of CO_2 Emissions from Nuclear, Wind, and Solar Power

Contention DEIS-3 states:

> The DEIS fails to compare the CO2 emissions of the [Uranium Fuel Cycle] to the CO2 emissions of wind and solar power.[157]

The Intervenors claim that the DEIS is incomplete because it does not consider the CO_2 footprint of STP Units 3 and 4 compared to alternatives, such as wind, solar, and geothermal.[158] Additionally, the Intervenors claim that the DEIS incorrectly assumes that these alternatives (or combinations thereof) are not viable baseload generation sources.[159] The Intervenors also reference part of the Power Comments as support for this contention.[160] As demonstrated below,

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154 *Ariz. Pub. Serv. Co.* (Palo Verde Nuclear Generating Station, Units 1 & 2), LBP-82-117A, 16 NRC 1964, 1992-93 (1982), *aff'd*, ALAB-713, 17 NRC 83 (1983). In upholding the licensing board's decision, the Appeal Board stated that "although an insufficient supply of condenser cooling water might necessitate a reduction in power levels (and perhaps total reactor shutdown), it would not pose a safety threat." *Palo Verde*, ALAB-713, 17 NRC at 84 n.2.

155 *South Texas Project*, LBP-09-25, slip op. at 12-13.

156 *Id.* at 14-16.

157 Motion at 7.

158 *Id.*

159 *Id.* at 8.

160 *Id.* at 8 nn. 27, 29.

Contention DEIS-3 is not admissible because it is not material, it is not adequately supported, and it does not demonstrate a genuine dispute of material fact.

The DEIS does not quantitatively compare the CO_2 emissions of STP Units 3 and 4 to wind, solar, and geothermal because the DEIS determined that these alternatives do not meet the need for baseload power generation.[161] An EIS is not required to evaluate the environmental impacts of alternatives if those alternatives are determined to not be feasible means of accomplishing the purpose of a project.[162] As the licensing board in the *Shearon Harris* COL proceeding explained, "unless in a particular instance there is in fact a *viable* alternative which has an extremely low carbon footprint, the footprint of the nuclear fuel cycle is immaterial to the decision the Agency must make, and therefore such a contention fails to create a genuine issue of *material* fact."[163] For this reason, Contention DEIS-3 does not raise a material issue, contrary to 10 C.F.R. § 2.309(f)(1)(iv), and does not identify a genuine dispute with the DEIS, contrary to 10 C.F.R. § 2.309(f)(1)(vi).

The Intervenors' claims regarding use of CAES for baseload power likewise do not support admission of this contention. To be a reasonable alternative, an "energy conversion technology should be developed, proven, and available in the relevant region."[164] The Intervenors have not identified any existing baseload CAES facilities anywhere in the world. Instead, the Intervenors discuss "the recent announcement of ConocoPhillips and General Compression of a CAES facility planned for Texas that would be suitable for baseload

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161 DEIS at 9-31.

162 *See Clinton ESP*, CLI-05-29, 62 NRC at 808.

163 *Progress Energy Carolinas, Inc.* (Shearon Harris Nuclear Power Plant, Units 2 & 3), LBP-08-21, 68 NRC 554, 579 (2008).

164 NUREG-1555, Office of Nuclear Reactor Regulation, Standard Review Plans for Environmental Reviews for Nuclear Power Plants, at 9.2.2-4 (Oct. 1999) (STP Attachment 21), *available at* http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr1555/sr1555.pdf.

generation."[165] That announcement, however, only discusses commencement of a "pilot project" in Texas and does not discuss any projects that could provide baseload power on the scale of STP Units 3 and 4.[166]

The Intervenors also reference a 2006 National Renewable Energy Laboratory ("NREL") concept paper about CAES.[167] Such a reference is subject to board scrutiny, "both for what it does and does not show."[168] This document makes clear that using wind power generation and CAES to provide baseload power is still only a "concept."[169] This document further points out that "[d]evelopment of the 'baseload' wind concept will require a greater understanding of the local geologic compatibility of air storage, and *additional work will be required to examine the feasibility* of advanced wind/CAES concepts described here."[170] This document does not support the viability of a CAES baseload project on the scale of STP Units 3 and 4.

The Power Comments further reference a 2007 news release regarding a wind farm project with Luminant and Shell WindEnergy Inc.[171] That news release, however, only states that these companies entered into a "joint development agreement" and planned to "explore the use" of CAES, not that they were moving ahead with a large-scale CAES project.[172]

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165 Motion at 7-8.

166 General Compression Signs Agreement with ConocoPhillips to Develop CAES Projects (STP Attachment 14).

167 NREL, Creating Baseload Wind Power Systems Using Advanced Compressed Air Energy Storage Concepts (Oct. 3, 2006) (STP Attachment 18) ("NREL Concept Paper"), *available at* http://www.nrel.gov/docs/fy07osti/40674.pdf.

168 *See Yankee Atomic Elec. Co.* (Yankee Nuclear Power Station), LBP-96-2, 43 NRC 61, 90 (1996), *rev'd in part on other grounds*, CLI-96-7, 43 NRC 235 (1996).

169 *See* NREL Concept Paper.

170 *Id.* (emphasis added).

171 Power Comments at 7.

172 *See* Luminant and Shell Join Forces to Develop a Texas-Sized Wind Farm (July 27, 2007) (STP Attachment 19), *available at* http://www.luminant.com/news/newsrel/detail.aspx?prid=1087.

Furthermore, there is nothing in that statement which indicates that the facility would produce baseload power.

The Power Comments also reference comments from Raymond Dean on Luminant's ER for Comanche Peak Units 3 and 4.[173] The Dean comments, however, are entirely theoretical and do not identify any existing baseload CAES facilities.

As a result, these documents identified by the Intervenors fail to provide adequate support for Contention DEIS-3, contrary to 10 C.F.R. § 2.309(f)(1)(v). A petitioner bears the burden to present the factual information or expert opinion necessary to support its contentions adequately, and failure to do so requires a board to reject the contentions.[174] As discussed above, the referenced documents do not support the Intervenors' claim that baseload power on the scale of STP Units 3 and 4 is viable using CAES. In particular, the Intervenors have not identified any such existing project.

Additionally, the Intervenors did not mention or refute the discussion of CAES in the DEIS. For example, DEIS Section 9.2.3.2 evaluates use of CAES in combination with wind generation, and identifies two existing CAES plants (290 MW and 110 MW) and a proposal for a 268 MW CAES plant in Iowa.[175] However, neither of those existing facilities is used for producing baseload power.[176] The DEIS concludes that "[t]o date, nothing approaching the scale of a 2700 MW(e) facility has been contemplated. Therefore, the review team concludes that the use of CAES in combination with wind turbines to generate 2700 MW(e) in Texas is

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173 Power Comments at 7.

174 *See* 10 C.F.R. § 2.309(f)(1)(v); *Yankee Nuclear*, CLI-96-7, 43 NRC at 262.

175 DEIS at 9-21.

176 *See, e.g.*, Boise State University, Overview of Compressed Air Energy Storage (Dec. 2007) (STP Attachment 20), *available at* http://coen.boisestate.edu/WindEnergy/resources/ER-07-001.pdf.

unlikely."[177] Also, the combination of alternatives considered by the Staff includes 200 MW(e) from wind power that "would need to be combined with an energy storage mechanism, such as CAES, to be a base-load resource."[178] The Intervenors have not discussed or disputed this information in the DEIS, and therefore have failed to demonstrate a genuine dispute with the DEIS, contrary to 10 C.F.R. § 2.309(f)(1)(vi).[179]

Finally, this contention seeks to re-litigate issues that were already rejected by the Board. Rejected Contention 20 claimed that the impacts of greenhouse gases from the uranium fuel cycle, including CO_2, were not adequately considered.[180] Rejected Contention 23 also challenged the ER's conclusion that renewables, such as wind and solar (including use of CAES), do not provide adequate baseload generating capacity.[181] The Board rejected both of these contentions because the Intervenors did not address the related information in the ER.[182] As discussed above, this same failure applies to Contention DEIS-3 because the Intervenors did not address information in the DEIS. Therefore, the Board should similarly reject Contention DEIS-3.

D. <u>Contention DEIS-4 - - Greenhouse Gas Mitigation Measures During Construction</u>

Contention DEIS-4 states:

> The DEIS analysis of STP 3 & 4 construction impacts related to [greenhouse gas ("GHG")] emissions assumes appropriate mitigation measures would be adopted but fails to discuss what

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177 DEIS at 9-21.

178 *Id.* at 9-27.

179 *See* Final Rule, Rules of Practice for Domestic Licensing Proceedings – Procedural Changes in the Hearing Process, 54 Fed. Reg. at 33,170; *see also Millstone*, CLI-01-24, 54 NRC at 358.

180 Petition at 44-45.

181 *Id.* at 49.

182 *South Texas Project*, LBP-09-21, slip op. at 34-35, 45.

> mitigation measures would be available to minimize GHG emissions during construction.[183]

The Intervenors claim that the DEIS does not meet the requirement of 10 C.F.R. § 51.70(b) that the DEIS be "analytic" because "the DEIS makes no attempt to determine what mitigation measures/alternatives are available let alone what actual effects on GHG emissions would be realized by such."[184] As demonstrated below, Contention DEIS-4 is not admissible because it is not material and it does not demonstrate a genuine dispute of material fact.

DEIS Section 4.7.1 addresses the meteorological and air-quality impacts of construction and preconstruction activities, including the impacts from greenhouse gases. While the DEIS states that preoperational activities would result in greenhouse gas emissions (principally CO_2), the DEIS estimates that the "total construction equipment CO_2 emission footprint for building two nuclear power plants at the STP site would be of the order of 70,000 metric tons, as compared to a total United States annual CO_2 emission rate of 6,000,000,000 metric tons."[185] The DEIS concludes:

> Based on its assessment of the relatively small construction equipment carbon footprint as compared to the United States annual CO_2 emissions, the review team concludes that the *atmospheric impacts of greenhouse gases from construction and preconstruction activities would not be noticeable* and *additional mitigation would not be warranted*.[186]

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[183] Motion at 8.

[184] *Id.* at 8-9.

[185] DEIS at 4-63.

[186] *Id.* (emphasis added); *see also id* at 4-65 ("[T]he review team concludes that the impacts of STP site development on air quality from emissions of criteria pollutants and CO_2 emissions are SMALL and that *no further mitigation is warranted*." (emphasis added)).

Therefore, the DEIS concludes that *no mitigation is warranted* because the impacts of greenhouse gases would not be noticeable. The Intervenors have not challenged this conclusion in the DEIS.[187]

The statement referenced by the Intervenors regarding "appropriate mitigation measures" refers to air quality as a whole and not specifically to greenhouse gases. The DEIS states that "the review team concludes that the impacts from STP Unit[s] 3 and 4 construction and preconstruction activities on air quality would not be noticeable because appropriate mitigation measures would be adopted."[188] In this regard, the DEIS identifies specific mitigation measures for air quality, including preparation of a Construction Environmental Controls Plan, dust controls (*e.g.*, watering unpaved roads), and a commitment to comply with applicable regulations.[189]

In summary, the Intervenors have mischaracterized the DEIS conclusions regarding greenhouse gas mitigation measures. Contrary to the Intervenors' characterization, the DEIS concludes that no mitigation is warranted for the construction impacts from greenhouse gas emissions, because the impacts of such emissions from construction would not be noticeable.[190] An intervenor's imprecise reading of a document cannot create an issue suitable for litigation.[191] As a result, Contention DEIS-4 "is [not] material to the findings the NRC must make," contrary to 10 C.F.R. § 2.309(f)(1)(iv), and fails to demonstrate a genuine dispute on a material issue of

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[187] Furthermore, this conclusion in the DEIS is consistent with the NRC's guidance in NUREG-1555, at 4.4.1-6 (STP Attachment 21), which states that mitigation of construction impacts is not required when the impacts are minor.

[188] DEIS at 4-63.

[189] *Id.* at 4-62 to 4-63.

[190] *Id.* at 4-63.

[191] *See, e.g.*, *Ga. Inst. of Tech.* (Georgia Tech Research Reactor, Atlanta, Georgia), LBP-95-6, 41 NRC 281, 300 (1995).

fact or law, contrary to 10 C.F.R. § 2.309(f)(1)(vi). Accordingly, this contention should be rejected.

E. Contention DEIS-5 - - Groundwater and Nonradiological Health

Contention DEIS-5 states:

> The DEIS conclusion that impacts caused by changes in global climate change "may not be insignificant" fails to meet the requirements of 10 CFR 51.70(b) to be "clear and analytic."[192]

The Intervenors claim that statements in the DEIS that climate change impacts are "not insignificant" are inconsistent with the conclusions that the cumulative impacts of groundwater use and to nonradiological health are SMALL.[193] As demonstrated below, Contention DEIS-5 is not admissible because it is not material and does not demonstrate a genuine dispute of material fact.

First, to the extent that the Intervenors are criticizing the use of the term SMALL, their criticism is legally without merit. That term is part of an accepted approach for characterizing environmental impacts. It is explicitly used in Appendix B to 10 C.F.R. Part 51 and is applied throughout the DEIS.[194]

Furthermore, to the extent that the Intervenors are criticizing the analysis in the DEIS, they have taken statements out of context and have mischaracterized the DEIS. For example, DEIS Section 7.2.1.2 addresses the cumulative impacts of groundwater use.[195] Regarding climate change, that evaluation states:

> The review team is also aware of the potential climate changes that could affect groundwater use. A recent compilation of the state of knowledge in this area (Karl et al. 2009) has been considered in the

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[192] Motion at 9.

[193] *Id.* at 9-10.

[194] *See, e.g.*, DEIS Tables 4-7, 5-21, 7-3, 9-20, 10-1.

[195] DEIS at 7-13 to 7-16.

> preparation of this EIS. Projected changes in the climate for the region during the life of proposed Units 3 and 4 include an increase in average temperature and a decrease in precipitation. This may result in less groundwater recharge. *While the changes that are attributed to climate change in these studies are not insignificant, the review team did not identify anything that would alter its conclusion regarding groundwater use below*.[196]

The DEIS concludes that "the cumulative effects to the groundwater resource from preconstruction, construction, and operation of STP Units 3 and 4, and other past, present, and reasonably foreseeable projects would be minimal, including the potential of decreased precipitation and increased temperature due to [global climate change]," and the cumulative impacts of groundwater use would be SMALL.[197] Therefore, although the DEIS considers changes due to climate change to be not insignificant, it considers the cumulative impacts of groundwater use due to all factors (including climate change) to be minimal. There is nothing inconsistent with this conclusion and the Intervenors have not demonstrated otherwise.

DEIS Section 7.7 addresses the cumulative impacts of nonradiological health.[198] Regarding climate change, that evaluation states:

> The review team is also aware of the potential climate changes that could affect human health—a recent compilation of the state of knowledge in this area (Karl et al. 2009) has been considered in the preparation of this EIS. Projected changes in the climate for the region during the life of proposed Units 3 and 4 include an increase in average temperature and a decrease in precipitation. Potential changes in water temperature and frequency of downpours could alter the presence of thermophilic microorganisms. *While the changes that are attributed to climate change in these studies are not insignificant, the review team did not identify anything that would alter its conclusion regarding the presence of etiological agents or change in the incidence of water-borne diseases*.[199]

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196 *Id.* at 7-15 (emphasis added).

197 *Id.* at 7-16.

198 *Id.* at 7-45 to 7-47.

199 *Id.* at 7-47 (emphasis added).

The DEIS evaluates the cumulative impacts to nonradiological health "resulting from the building and operation of proposed Units 3 and 4, along with a review of potential impacts from other past, present, and reasonably foreseeable projects and urbanization" and concludes that the "cumulative impacts on public and worker nonradiological health would be SMALL."[200] Therefore, although the DEIS considers changes due to climate change to be not insignificant, it considers the cumulative impacts to nonradiological health due to all factors (including climate change) to be SMALL. There is nothing inconsistent with this conclusion and the Intervenors have not demonstrated otherwise.

The Intervenors have mischaracterized the DEIS conclusions regarding the contribution of climate change to the cumulative impacts of groundwater use and nonradiological health. As discussed above, for both of these issues the DEIS considers the overall changes associated with climate change to be "not insignificant," but considers the specific impacts with respect to groundwater and nonradiological health to be SMALL. An intervenor's imprecise reading of a document cannot create an issue suitable for litigation.[201] As a result, Contention DEIS-5 "is [not] material to the findings the NRC must make," contrary to 10 C.F.R. § 2.309(f)(1)(iv), and fails to demonstrate a genuine dispute on a material issue of fact or law, contrary to 10 C.F.R. § 2.309(f)(1)(vi). The Intervenors also are quibbling over the choice of words in the DEIS rather than the nature of the impacts referenced in the DEIS. In this regard, as the Commission has noted, "[o]ur boards do not sit to 'flyspeck' environmental documents or to add details or nuances."[202]

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200 *Id.*

201 *See, e.g.*, *Georgia Tech*, LBP-95-6, 41 NRC at 300.

202 *Grand Gulf*, CLI-05-4, 61 NRC at 13.

F. Contention DEIS-6 - - Water Use by the Las Brisas Power Plant

Contention DEIS-6 states:

> The DEIS analysis of surface water availability fails to account for the sale of 19,356 acre ft/yr from the Colorado River to the Las Brisas coal-fired power plant.[203]

The Intervenors contend that the "DEIS does not discuss this transaction nor the effects thereof on the assumed volume of water available from the Colorado River for Units 3&4 operations."[204] As demonstrated below, Contention DEIS-6 is inadmissible because it is immaterial and does not demonstrate a genuine dispute with the DEIS.

DEIS Section 2.3.2.1 addresses surface water use and availability. Contrary to the Intervenors' allegation, use of the water right that may be sold to Las Brisas is accounted for in the DEIS analysis. The water right at issue is a portion of the Garwood water right owned by the city of Corpus Christi.[205] This water right is accounted for in the 2006 Lower Colorado Regional Water Planning Group ("LCRWPG") Region K Water Plan relied upon in the DEIS.[206] The LCRWPG Plan states: "Water availability will be based on the assumption that all senior water rights in the basin are being fully utilized. That is, water user groups cannot depend on 'borrowing' water from unused water rights."[207] Consequently, the sale of the Corpus Christi Garwood water right to the Las Brisas plant would not alter the conclusions in the DEIS, because use of this water is already accounted for in the LCRWPG Plan and the DEIS.

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203 Motion at 10.

204 *Id.* at 10-11.

205 Fanny S. Chirinos, Corpus Christi Caller Times, Las Brisas Proposes Water Pipeline (Feb. 11, 2009) (STP Attachment 22), *available at* http://www.caller.com/news/2009/feb/11/las-brisas-proposes-water-pipeline/.

206 *See* Lower Colorado Regional Water Planning Group, 2006 Region "K" Water Plan for the Lower Colorado Regional Water Planning Group, at 3-12 (Jan. 2006) (STP Attachment 23), *available at* http://www.twdb.state.tx.us/rwpg/2006_RWP/RegionK/Chapter%203.pdf. The LCRWPG Plan is discussed in DEIS Section 2.3.2.1.

207 *Id.* at 3-2.

Therefore, this contention is not material, contrary to 10 C.F.R. § 2.309(f)(1)(iv), and does not demonstrate a genuine dispute, contrary to 10 C.F.R. § 2.309(f)(1)(vi).[208] Accordingly, it should be rejected.

VI. <u>CONCLUSION</u>

For the foregoing reasons, the Intervenors' proposed contentions are untimely, seek to relitigate contentions that were previously rejected by the Board, and do not meet the contention admissibility requirements. Therefore, the contentions submitted by the Intervenors related to the DEIS should be rejected.

Respectfully submitted,

Executed in Accord with 10 C.F.R. § 2.304(d)

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this fourteenth day of June 2010

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[208] Additionally, there has not been a "sale of 19,356 acre ft/yr from the Colorado River to the Las Brisas coal-fired power plant." Motion at 10. The Corpus Christi City Council authorized the City Manager to *enter into negotiations* with representatives of the Las Brisas Energy Center regarding a contract to supply water to the *proposed* facility. Denise Malan, Corpus Christi Caller Times, Corpus Christi Council Gives City Manager Authority to Sell Water to Las Brisas Energy Center (May 11, 2010) (STP Attachment 24), *available at* http://www.caller.com/news/2010/may/11/corpus-christi-council-gives-city-manager-to-to/. Neither the Power Comments nor the article relied upon in the Power Comments states that 19,356 acre-ft/yr of water from the Colorado River has been sold to the Las Brisas coal-fired power plant, and such sale is only speculation at this time.

STP Attachment 1

Documents Referenced in the Motion and Power Comments

Referenced Document	Date	Contention	Citation	Notes
HR 5019, "Home Star Energy Retrofit Act of 2010"	4/14/2010	DEIS-1	Motion at 3; Power Comments at 6	HR 5019 was introduced in the U.S. House of Representatives on April 14, 2010. This bill has not been signed into law.
Jim Herndon, Nexant, "Measurement and Verification of CPS Energy's 2009 DSM Program Offerings"	**4/26/2010**	**DEIS-1**	**Power Comments at 2 n.3**	
PUC Project # 37623, "Rulemaking Proceeding to Amend Energy Efficiency Rules"	1/28/2010	DEIS-1	Power Comments at 2 n.4	Although the Intervenors stated 3/31/2010 as the date for this project, the rulemaking text has been available at least since 1/28/2010. *See* http://www.puc.state.tx.us/rules/rulemake/37623/37623pub.pdf. No rulemaking has been completed.
Dan Woodfin, ERCOT, "May 2010 Load Forecast and Reserve Margin Update"	**5/18/2010**	**DEIS-1**	**Power Comments at 2 n.5, 3-4**	
PUC Project # 35792, "Rulemaking to Relating to the Goal for Renewable Energy"	12/21/2009	DEIS-1	Power Comments at 4 & n.9	Although the Intervenors stated 5/11/2010 as the date for this project, the rulemaking text has been available at least since 12/21/2009. *See* http://www.puc.state.tx.us/rules/rulemake/35792/35792.cfm. No rulemaking has been completed.

Referenced Document	Date	Contention	Citation	Notes
SECO, "SECO Proposes Updates to Building Energy Performance Standards"	3/11/2010	DEIS-1	Power Comments at 4 & nn.10, 13	
Written Testimony of Kate Robertson	4/2/2009	DEIS-1	Power Comments at 4 n.11	
ACEEE Report No. E073, "Potential for Energy Efficiency, Demand Response, and Onsite Renewable Energy to Meet Texas's Growing Electricity Needs"	3/2007	DEIS-1	Power Comments at 4 & n.12	
Website for Building Code's Assistance Project	2/9/2010	DEIS-1	Power Comments at 5 & nn.14-15	While the exact date of the website referenced by the Intervenors is unknown, the publication date of the information referenced by the Intervenors from this website is 2/9/2010. *See* http://bcap-ocean.org/resource/energy-code-calculator.
"State Profiles of Energy Efficiency Opportunities in the South: Texas"	4/13/2010	DEIS-1	Power Comments at 5 nn.16-19	
PrairieGold Venture Partners, "General Compression Signs Agreement with ConocoPhillips to Develop CAES Projects"	4/14/2010	DEIS-1, 3	Power Comments at 6-7 & nn.20-21	
Raymond Dean, "Comments Regarding Luminant's Revision to the Comanche Peak Nuclear Power Plant, Units 3 & 4 COL Application Part 3 – Environmental Report"	1/4/2010	DEIS-1, 3	Power Comments at 7 & nn.23-25	Although this document is not dated, it was filed on 1/4/2010 in the combined license proceeding for Comanche Peak Units 3 and 4.
EPA, "Climate Change Indicators in the United States"	**4/2010**	**DEIS-2**	**Motion at 5; Power Comments at 1, 8-9**	
Kristin Shrader-Frechette, Modern Energy Review, "Greenhouse Emissions and Nuclear Energy"	8/2009	DEIS-2, 3	Motion at 5, 6 n.16, 7 n.23	

Referenced Document	Date	Contention	Citation	Notes
NRC, Information Notice No. 84-71, “Graphitic Corrosion of Cast Iron in Salt Water”	9/6/1984	DEIS-2	Motion at 6 n.19	
John Nelson, “Cooling Towers & Salt Water”	11/5/1986	DEIS-2	Motion at 6 n.16	
Scott Tinker, “Water Demand Projections for Power Generation in Texas”	8/31/2008	DEIS-2, 6	Power Comments at 1 n.1, 11 n.31	
U.S. Global Change Research Program, “Global Climate Change Impacts in the United States”	2009	DEIS-2	Power Comments at 10 n.29	
Environmental Defense Fund, “Energy Water Nexus in Texas”	4/2009	DEIS-2	Power Comments at 11 & n.30	
Luminant, “Luminant and Shell Join Forces to Develop a Texas-Sized Wind Farm”	7/27/2007	DEIS-3	Power Comments at 7 & n.22	
Benjamin Sovacool, “Valuing the Greenhouse Gas Emissions from Nuclear Power: A Critical Survey”	6/2008	DEIS-3	Motion at 7 n.23	
NREL, “Creating Baseload Wind Power Systems Using Advanced Compressed Air Energy Storage Concepts”	10/3/2006	DEIS-3	Motion at 8 n.28	
Corpus Christi Caller Times, “Corpus Christi Council Gives City Manager Authority to Sell Water to Las Brisas Energy Center”	**5/12/2010**	**DEIS-6**	**Power Comments at 11 n.32**	

STP Attachment 2

Demand Response

Reducing Your Load This Summer Can Pay Off for Commercial, Industrial Customers

CPS Energy's Demand Response program is a voluntary load curtailment program for our commercial and industrial customers. The program is designed to reduce CPS Energy's peak load growth by incentivizing customers to shed electric loads on peak summer days. The Demand Response program is an integral part of CPS Energy's strategy to save 771 megawatts by the year 2020.

Demand Response season begins June 1 and ends September 30. Demand Response events occur on weekdays between 3 p.m. and 6 p.m. Demand Response customers receive a two-hour advanced notification of when to initiate and end their curtailment.

Customer Testimonials -- See Who Is Already Realizing the Benefits of Demand Response!

Program Benefits

Demand Response provides financial incentives and other benefits to participants, including:

- Reducing energy use during peak demand days
- Helps keep electricity costs down during summer bill months
- Helps keep established summer peak low and positively affect winter bills
- Helps to delay the construction of new, expensive power plants and keeps rates low
- Monitored and analyzed post-event performances
- No financial penalties for under or over performance

Program Requirements

Demand Response is limited to commercial and industrial electric customers with:

- A CPS Energy account manager
- Demonstrated, curtailable load of at least 100 kilowatts (load may be aggregated, at least 50 kilowatts per customer site)
- An Interval Data Recorder (IDR) meter

Financial Incentives

Incentives are offered to CPS Energy commercial and industrial customers who voluntarily agree to reduce their electric load by an agreed-upon amount when CPS Energy calls a peak event.

Incentive payments are calculated based on the customer's overall curtailment performance during the summer season. Each curtailment event is measured and verified by CPS Energy. Customers choose to receive their incentive payment as check or credit posted to their account.
For more information, please contact your CPS Energy account manager or contact or send your Demand Response questions to ProductsandServices@CPSEnergy.com.

Commercial Energy Efficiency

Demand Response Testimonials
Energy Efficiency and Your Company's Bottom Line

STP Attachment 3

Nexant
The Power of Experience

Demand Side Management Potential Study

For CPS Energy

Terry Fry, Sr. Vice President,
Energy and Carbon Management

November 24, 2008

Nexant Corporate Profile

- Formed on January 1, 2000
- Twenty corporate, representative, and project offices around the world
- Total staff of 325 employees—including software developers, energy engineers, and consultants
- 1,700 energy industry assignments in over 70 countries
- Recognized leader in power network software development and energy efficiency and incentive programs

Energy and Carbon Management—Business Focus

National leader in the innovative design, implementation, and evaluation of many of the largest commercial, industrial, and residential energy efficiency incentive programs in the United States

- Supports end-to-end DSM program consulting to utilities throughout North America:
  - Program design, implementation, administration, tracking, reporting, and evaluation
  - Demand-response implementation
  - Strategic studies and regulatory support
- Provides technical services to large energy end users and service providers:
  - Energy auditing, commissioning, retrocommissioning
  - Performance measurement and verification
  - Litigation support
  - Owner's representation

Energy and Carbon Management

U.S. Energy Management Projects

Sample of Market Potential Studies

Investor Owned Utilities

- Iowa Utility Association
- Georgia Power Company
- Xcel Energy
- PacifiCorp
- Southern California Edison
- Cheyenne (WY) Light, Fuel, and Power
- Reliant Energy
- Idaho Power

Public Utility Systems

- City of Redding (CA)
- Roseville (CA) Electric
- New York Power Authority
- City of St. George (UT)
- Platte River Power Authority

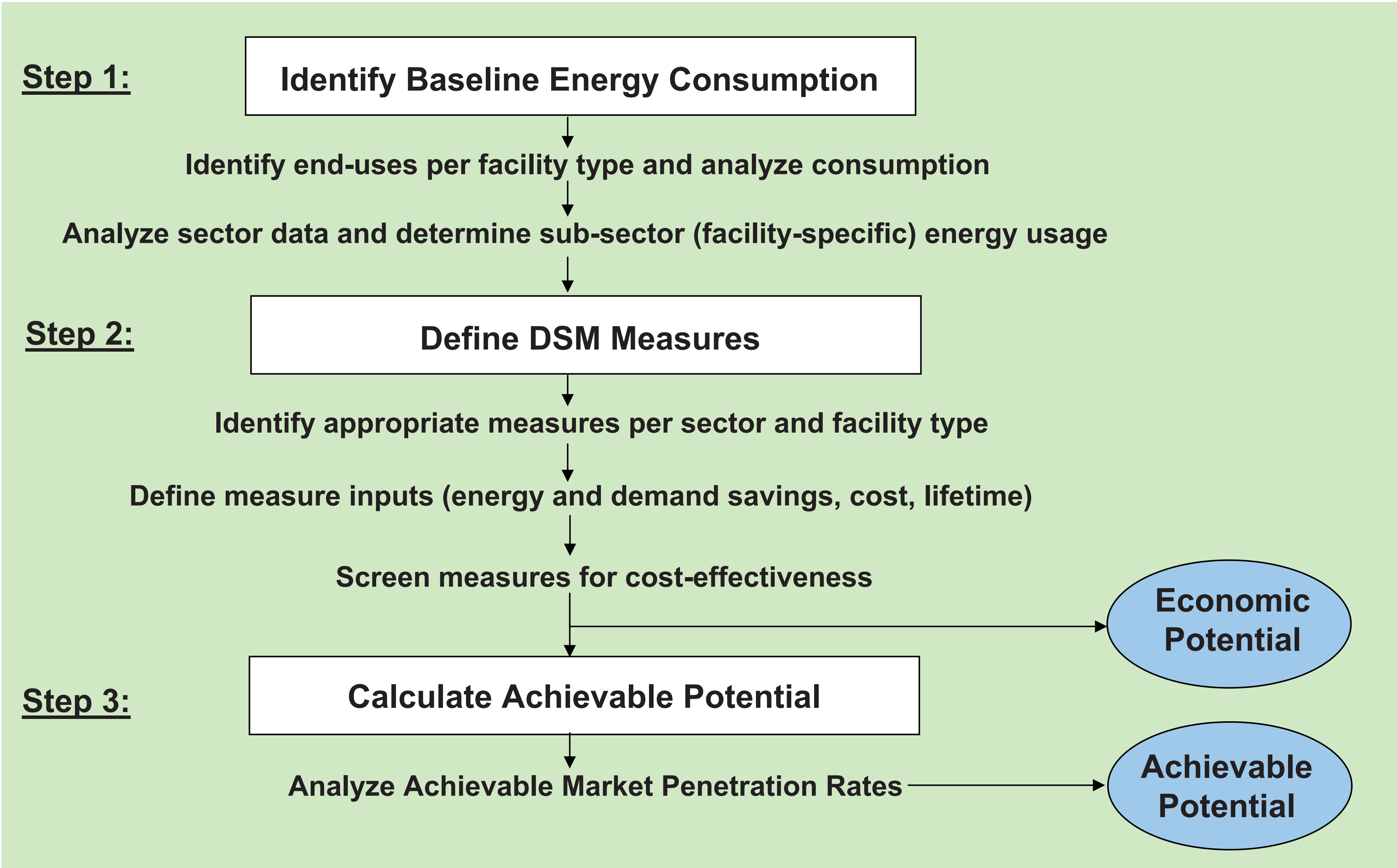
Market Potential Study Overview

- ***Demand side management (DSM) programs encourage customers to improve the efficiency of equipment, buildings, and processes, thereby saving electricity and reducing system demand.***

- ***Goal of the market potential study is to evaluate the DSM resources available to CPS Energy's customers across the three primary sectors:***
  - ***Residential***
  - ***Commercial***
  - ***Industrial***

- ***The study results in a model of the cost-effective DSM potential available through 2020***

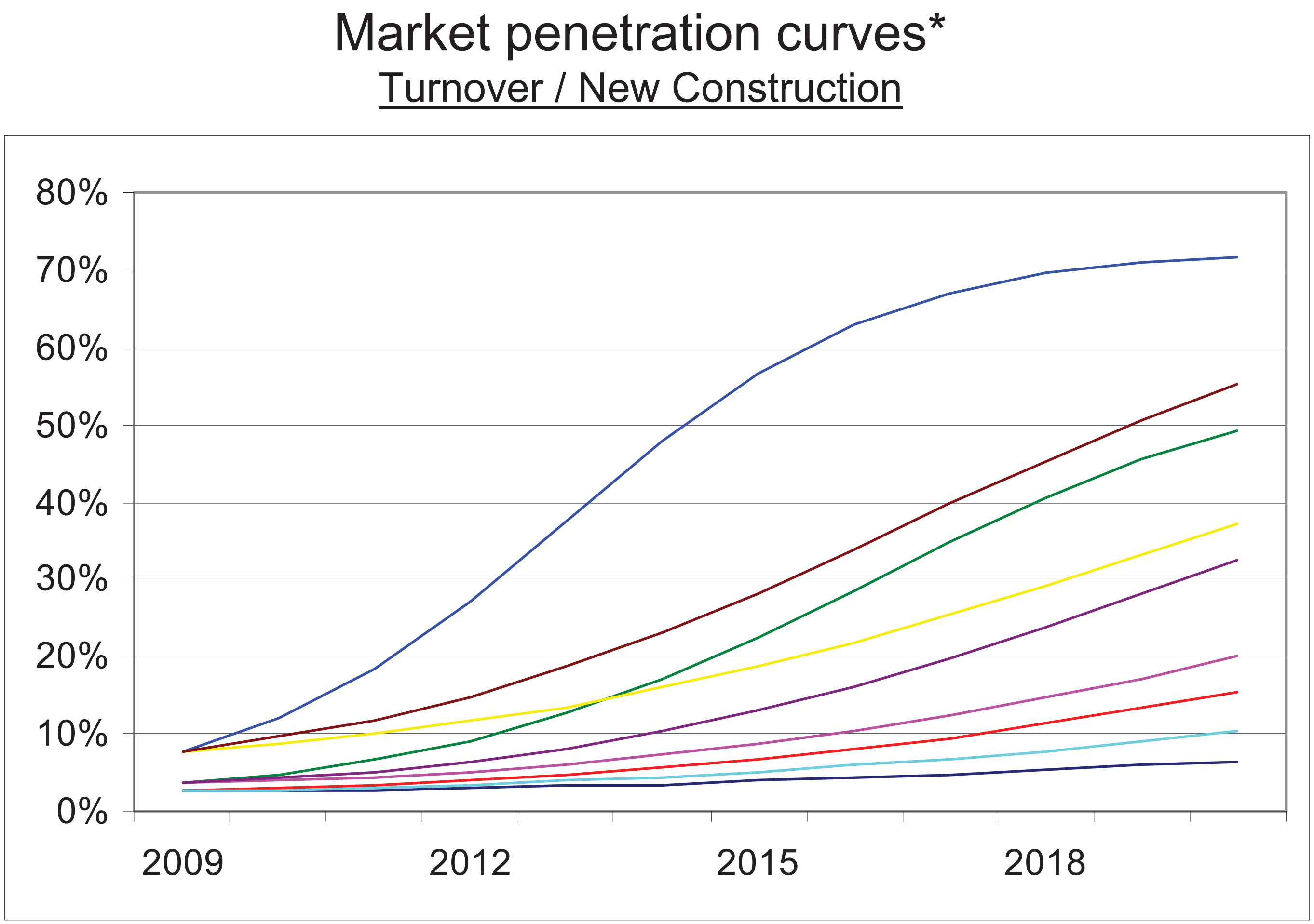
Market Potential Study Process



Achievable Potential

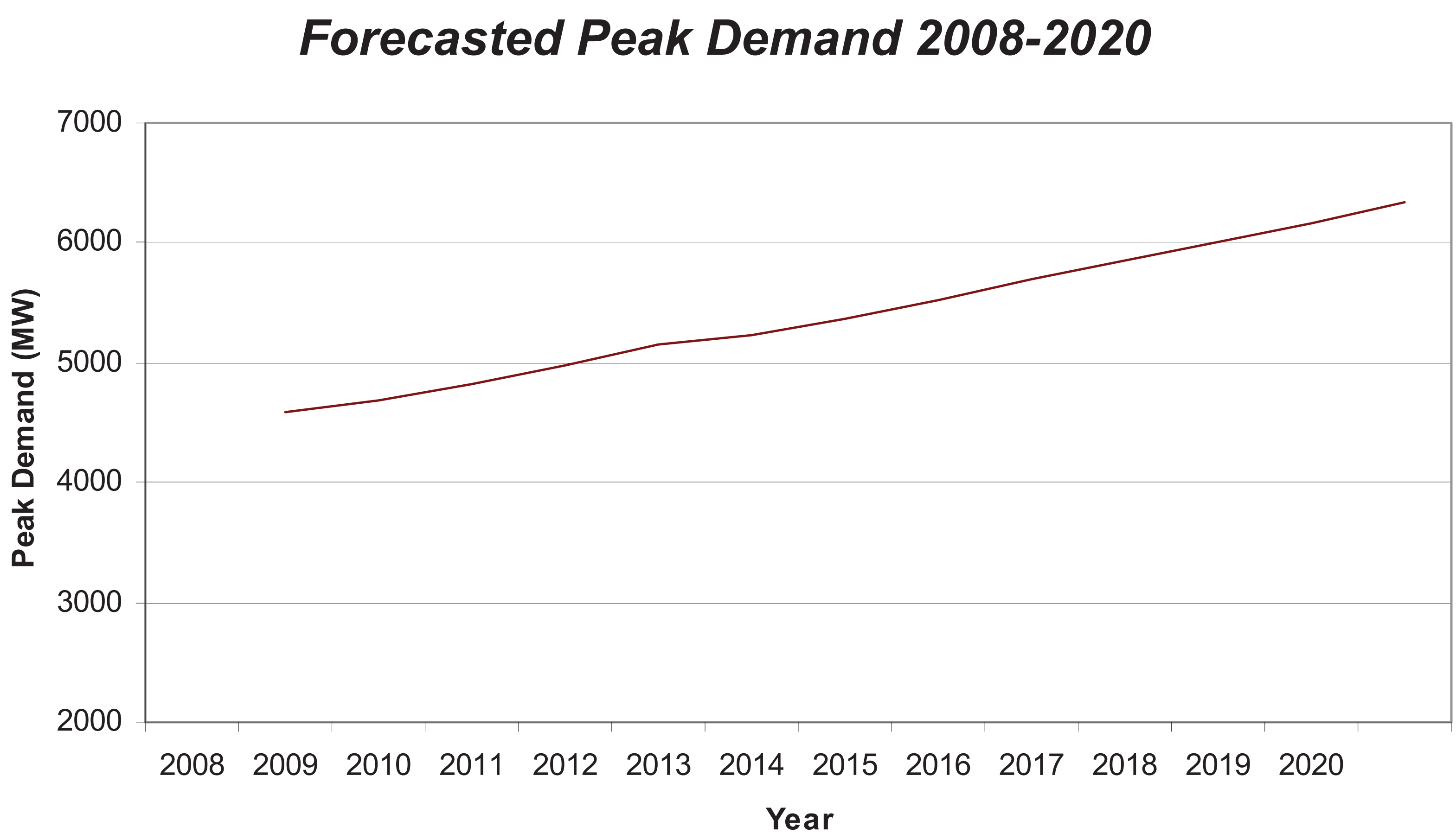
- Achievable potential is calculated by incorporating the cost effective measures into the defined baseline and applying appropriate market penetration rates.
- The market penetration rate is the rate of acceptance of a DSM program or measure over time.
- Because program implementation scenarios have a direct influence over such market penetration rates, Nexant analyzed three implementation scenarios:
  - "Low" incentives: Incentives subsidize 25% of the incremental customer costs to implement the DSM measure
  - "Moderate" incentives: Incentives subsidize 50% of the incremental measure costs
  - "Aggressive" incentives: Incentives subsidize 75% of the incremental measure costs

Market Penetration Curves



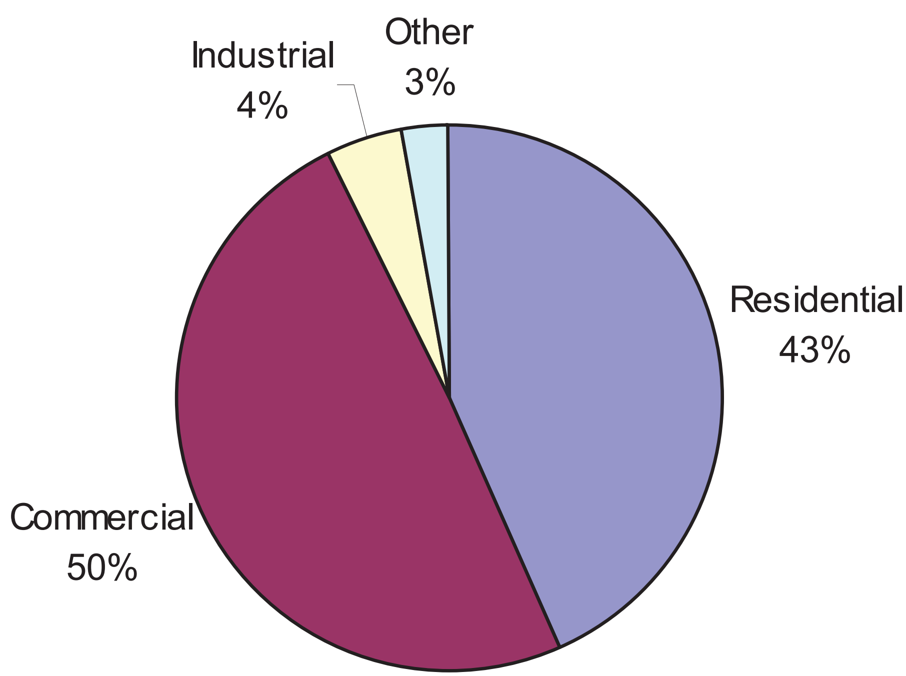
* Separate curves were used for retrofit opportunities and for turnover/new construction

CPS Energy Forecasted Demand Growth



CPS Energy Sector and End-Use Characteristics

*2008 Electricity Sales by Sector**



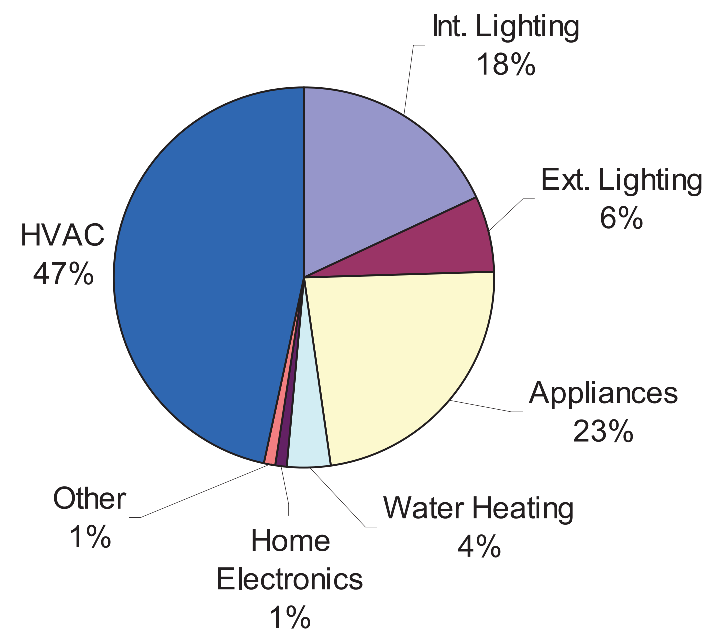
*The Industrial Sector was defined by Nexant based on facility NAICS codes

Residential Sector Analysis

Aggressive incentive scenario results:

- **Peak demand reduction potential of 241 MW by 2020**
- **Energy savings potential of 1,424 GWh by 2020**
- **Total Program Cost (including incentives, administrative, and marketing costs) of $366 million**
- **Total Program Benefits of $1.04 billion to CPS Energy**

Savings Potential by End-Use

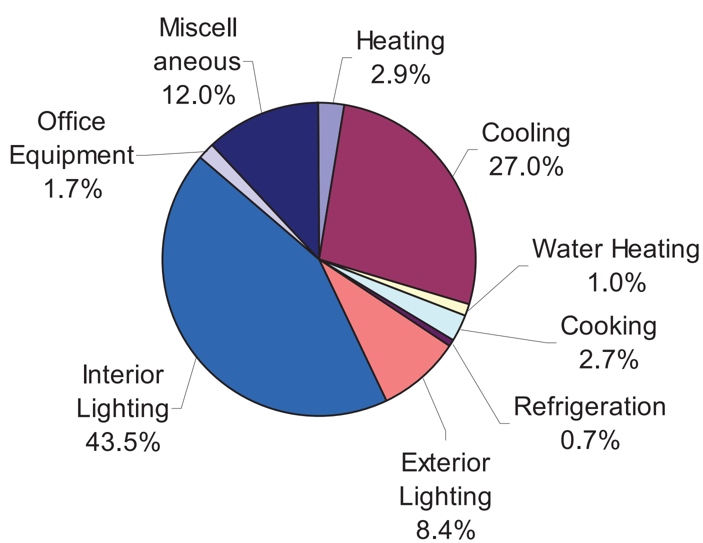


Commercial Sector Analysis

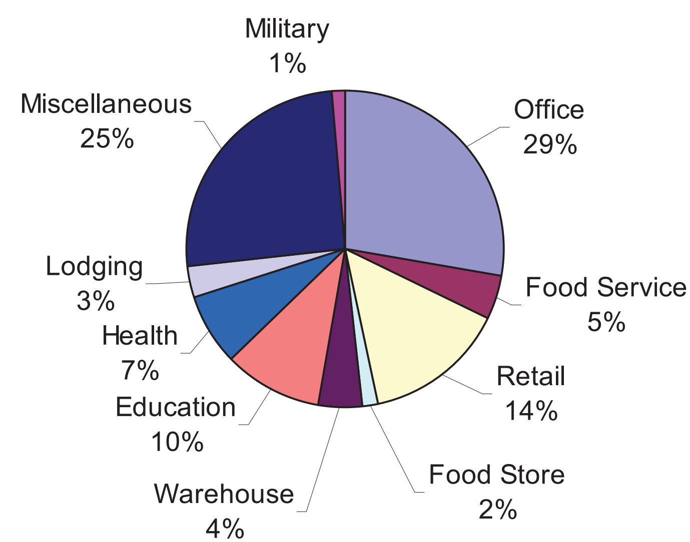
Aggressive incentive scenario results:

- **Peak demand reduction potential of 319 MW by 2020**
- **Energy savings potential of 1,119 GWh by 2020**
- **Total Program Cost (including incentives, administrative, and marketing costs) of $259 million**
- **Total Program Benefits of $362 million to CPS Energy**

Savings Potential by End-Use



Savings Potential by Facility Type

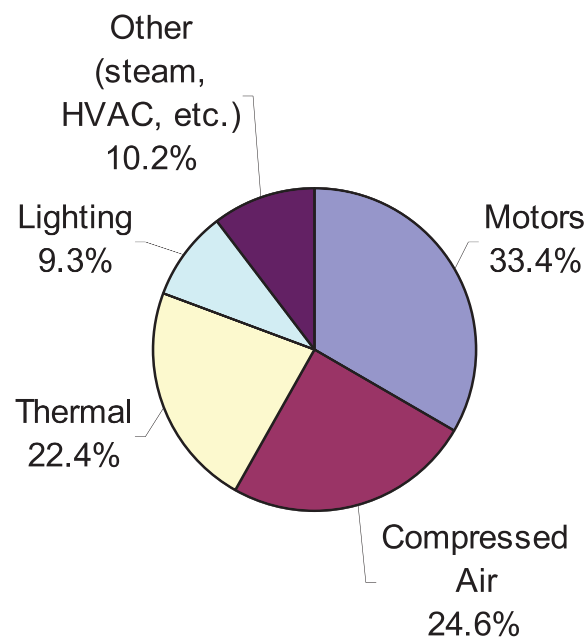


Industrial Sector Analysis

Aggressive incentive scenario results:

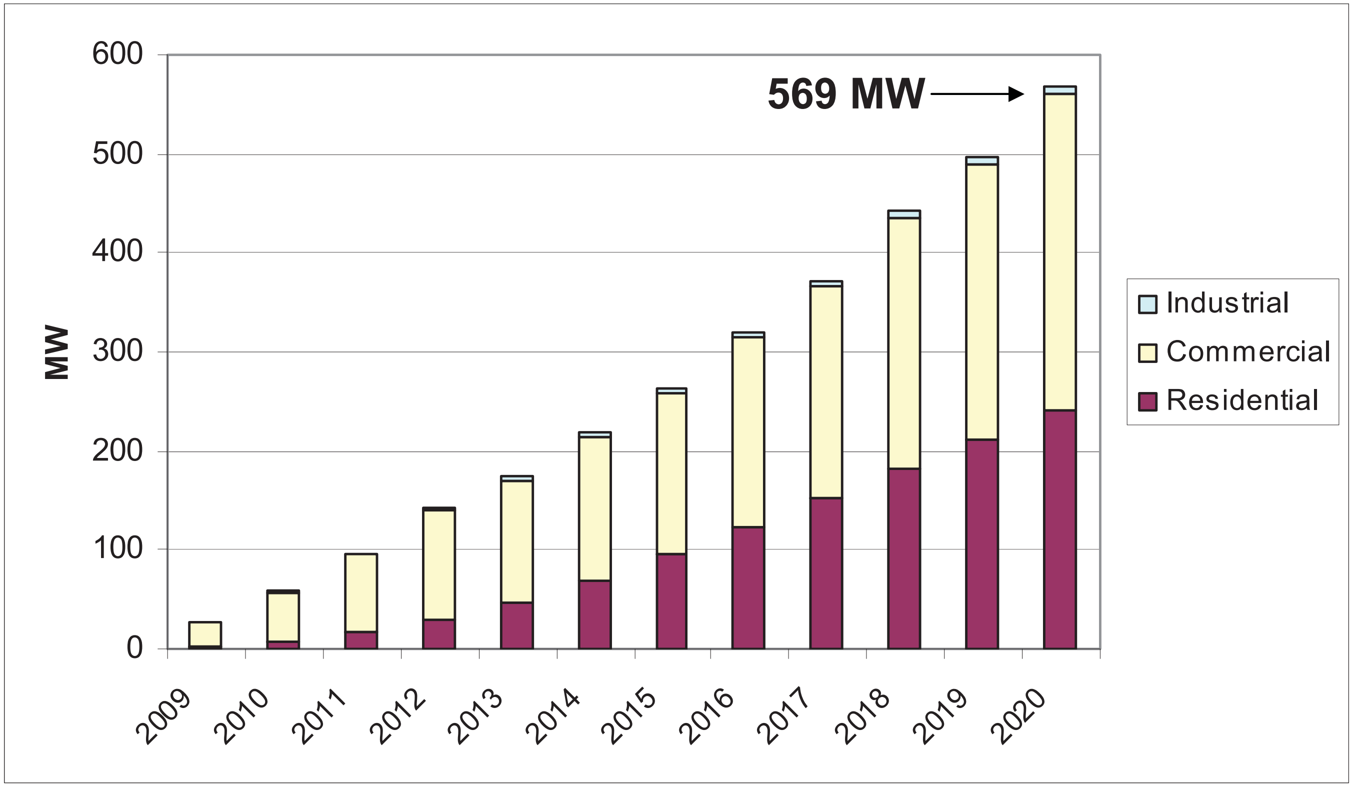
- **Peak demand reduction potential of 9 MW by 2020**
- **Energy savings potential of 75 GWh by 2020**
- **Total Program Cost (including incentives, administrative, and marketing costs) of $10 million**
- **Total Program Benefits of $27 million to CPS Energy**

Savings Potential by End-Use



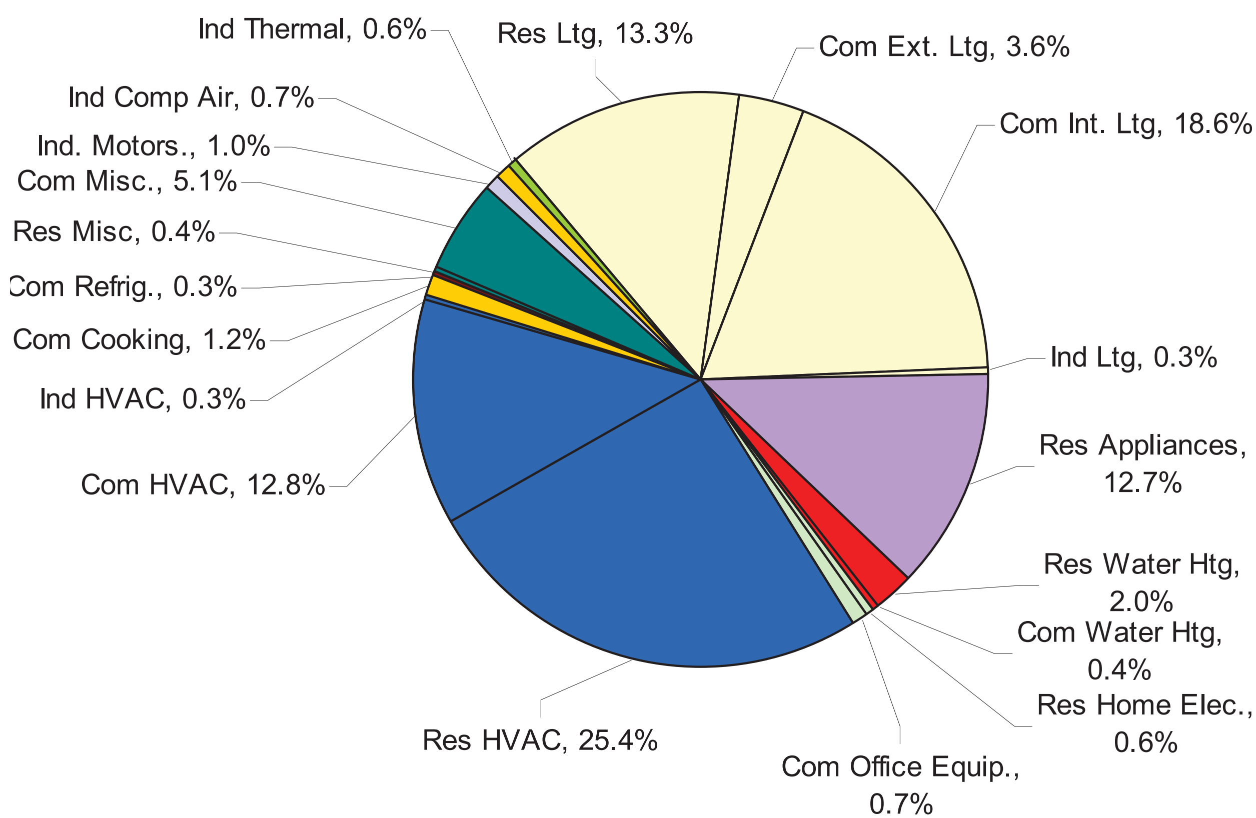
Achievable Potential Summary

Total Achievable Potential – Peak Demand Reduction

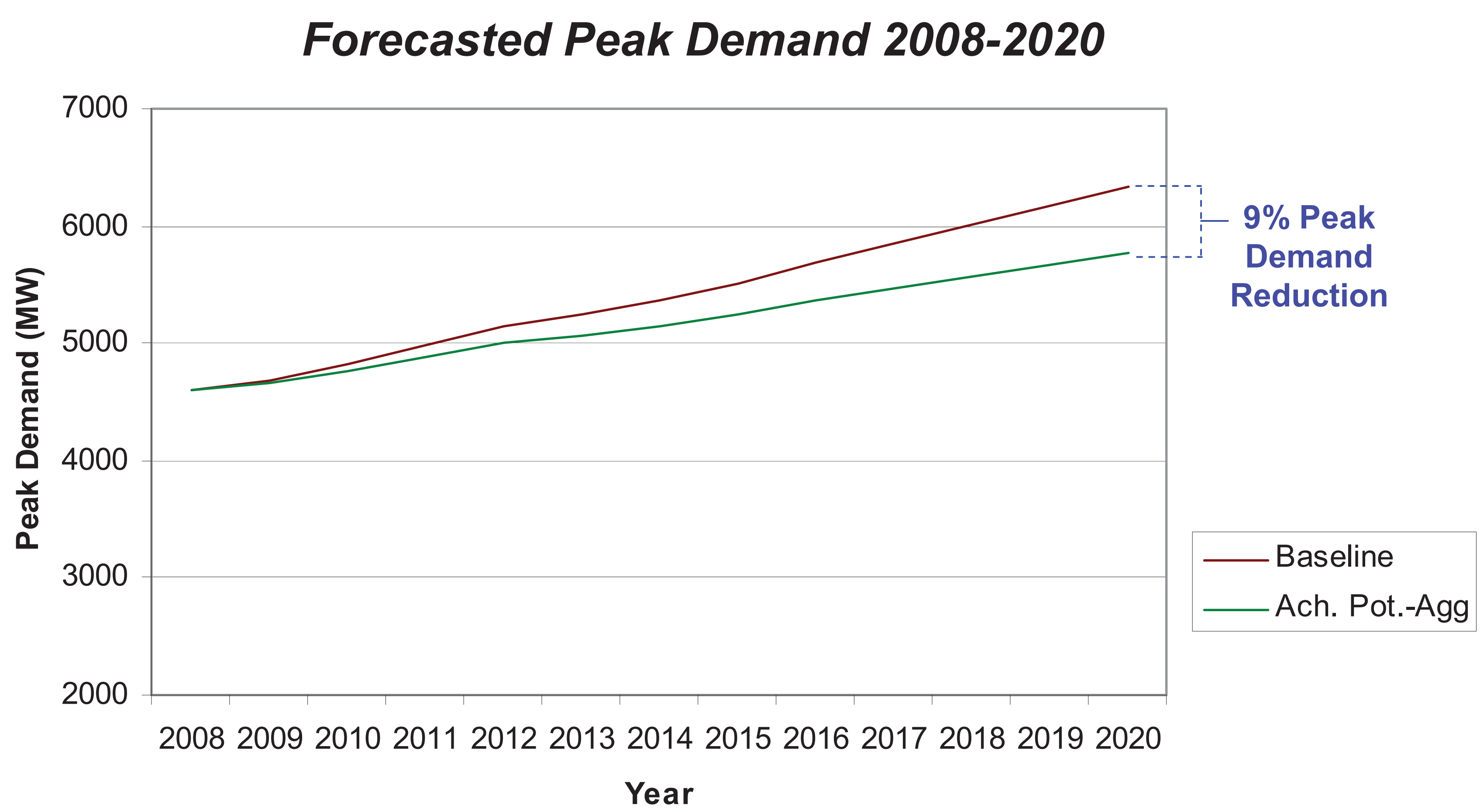


Achievable Potential Summary

Achievable Potential by End-Use



CPS Energy Forecasted Demand Growth



STP Attachment 4

REPORT ON THE CAPACITY, DEMAND, AND RESERVES IN THE ERCOT REGION

System Planning

May 2009

ERCOT
2705 West Lake Drive
Taylor, Texas 76574

Contents

Disclaimer

CDR WORKING PAPER

FOR PLANNING PURPOSES ONLY

This ERCOT Working Paper has been prepared for specific ERCOT and market participant purposes and has been developed from data provided by ERCOT market participants. The data may contain errors or become obsolete and thereby affect the conclusions and opinions of the Working Paper. ERCOT MAKES NO WARRANTY, EXPRESS OR IMPLIED, INCLUDING ANY WARRANTY OF MERCHANTABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE, AND DISCLAIMS ANY AND ALL LIABILITY WITH RESPECT TO THE ACCURACY OF SAME OR THE FITNESS OR APPROPRIATENESS OF SAME FOR ANY PARTICULAR USE. THIS ERCOT WORKING PAPER IS SUPPLIED WITH ALL FAULTS. The specific suitability for any use of the Working Paper and its accuracy should be confirmed by each ERCOT market participant that contributed data for this Working Paper.

This Working Paper is based on data submitted by ERCOT market participants as part of their Annual Load Data Request (ALDR) and their generation asset registration and on data in the EIA-411. As such, this data is updated on an ongoing basis, which means that this report can be rendered obsolete without notice.

Definitions

Available Mothballed Generation
The probability that a mothballed unit will return to service, as provided by its owner, multiplied by the capacity of the unit. Return probabilities are considered protected information under the ERCOT Protocols and therefore are not included in this report.

BULs
Balancing up load. Loads capable of reducing the need for electrical energy when providing Balancing Up Load Energy Service as described in the ERCOT Protocols, Section 6, Ancillary Services. BULs are not considered resources as defined by the ERCOT Protocols.

Effective Load-Carrying Capability (ELCC) of Wind Generation
The amount of wind generation that the Generation Adequacy Task Force (GATF) has recommended to be included in the CDR. The value is 8.7% of the nameplate capacity listed in the Unit Capacities tables, both installed capacity and planned capacity.

LaaRs (Loads acting as resources)
Load capable of reducing or increasing the need for electrical energy or providing Ancillary Services to the ERCOT System, as described in the ERCOT Protocols, Section 6, Ancillary Services. These Resources may provide the following Ancillary Services: Responsive Reserve Service, Non-Spinning Reserve Service, Replacement Reserve Service, and Regulation Service. The Resources must be registered and qualified by ERCOT and will be scheduled by a Qualified Scheduling Entity

Mothballed Capacity
The difference in the available mothballed generation (see definition above) and the total mothballed capacity. This value is zero in the upcoming Summer CDR Report because there isn't enough time to return those units to service before the start of the summer.

Mothballed Unit
A generation resource for which a generation entity has submitted a Notification of Suspension of Operations, for which ERCOT has declined to execute an RMR agreement, and for which the generation entity has not announced retirement of the generation resource.

Net Dependable Capability
Maximum sustainable capability of a generation resource as demonstrated by performance testing.

Non-Synchronous Tie
Any non-synchronous transmission interconnection between ERCOT and non-ERCOT electric power systems

Other Potential Resources
Capacity resources that include one of the following:

• Remaining "mothballed" capacity not included as resources in the reserve margin
• Remaining DC tie capacity not included as resources in the reserve margin calculation,
• New generating units that have initiated full transmission interconnection studies through the ERCOT generation interconnection process (Note that new wind generating units would be included based on the appropriate discounted capacity value applied to existing wind generating units.)

Planned Units in Full Interconnection Study Phase
To connect new generation to the ERCOT grid, a generation developer must go through a set procedure. The first step is a high-level screening study to determine the effects of adding the new generation on the transmission system. The second step is the full interconnection study. These are detailed studies done by the transmission owners to determine the effects of the addition of new generation on the transmission system.

Private Networks
An electric network connected to the ERCOT transmission grid that contains load that is not directly metered by ERCOT (i.e., load that is typically netted with internal generation).

Reliability Must-Run (RMR) Unit
A generation resource unit operated under the terms of an agreement with ERCOT that would not otherwise be operated except that they are necessary to provide voltage support, stability or management of localized transmission constraints under first contingency criteria.

Signed IA (Interconnection Agreement)
An agreement that sets forth requirements for physical connection between an eligible transmission service customer and a transmission or distribution service provider

Switchable Unit
A generation resource that can be connected to either the ERCOT transmission grid or a grid outside the ERCOT Region.

2009 Report on the Capacity, Demand, and Reserves in the ERCOT Region

Summer Summary

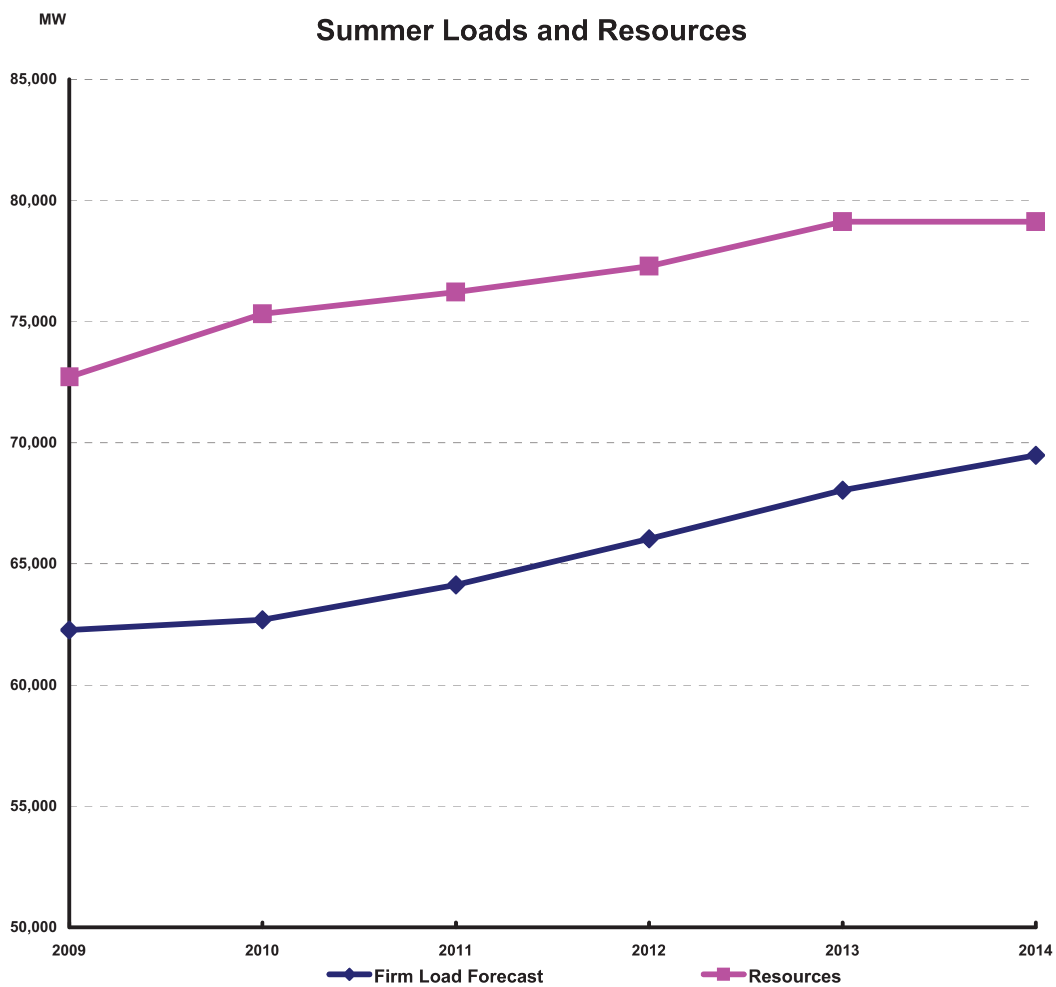
Load Forecast:	2009	2010	2011	2012	2013	2014
Total Summer Peak Demand, MW	63,491	64,056	65,494	67,394	69,399	70,837
less LAARs Serving as Responsive Reserve, MW	1,115	1,115	1,115	1,115	1,115	1,115
less LAARs Serving as Non-Spinning Reserve, MW	0	0	0	0	0	0
less BULs, MW	0	0	0	0	0	0
less Energy Efficiency Programs (per HB3693)	110	242	242	242	242	242
Firm Load Forecast, MW	**62,266**	**62,699**	**64,137**	**66,037**	**68,042**	**69,480**

Resources:	2009	2010	2011	2012	2013	2014
Installed Capacity, MW	63,492	61,800	61,800	61,800	61,800	61,800
Capacity from Private Networks, MW	5,313	5,318	5,318	5,318	5,318	5,318
Effective Load-Carrying Capability (ELCC) of Wind Generation, MW	708	708	708	708	708	708
RMR Units to be under Contract, MW	115	0	0	0	0	0
Operational Generation, MW	**69,628**	**67,826**	**67,826**	**67,826**	**67,826**	**67,826**
50% of Non-Synchronous Ties, MW	553	553	553	553	553	553
Switchable Units, MW	2,848	2,848	2,848	2,848	2,848	2,848
Available Mothballed Generation , MW	0	401	479	479	479	479
Planned Units (not wind) with Signed IA and Air Permit, MW	0	3,769	4,389	5,414	7,206	7,206
ELCC of Planned Wind Units with Signed IA, MW	0	76	121	168	211	211
Total Resources, MW	**73,029**	**75,472**	**76,215**	**77,287**	**79,122**	**79,122**
less Switchable Units Unavailable to ERCOT, MW	317	158	0	0	0	0
less Retiring Units, MW	0	0	0	0	0	0
Resources, MW	**72,712**	**75,314**	**76,215**	**77,287**	**79,122**	**79,122**
Reserve Margin	**16.8%**	**20.1%**	**18.8%**	**17.0%**	**16.3%**	**13.9%**
(Resources - Firm Load Forecast)/Firm Load Forecast						

Other Potential Resources:	553	13,889	23,094	28,794	31,399	33,140
Mothballed Capacity , MW	0	5,478	7,125	7,125	7,125	7,125
50% of Non-Synchronous Ties, MW	553	553	553	553	553	553
Planned Units in Full Interconnection Study Phase, MW	0	7,858	15,417	21,116	23,722	25,463

2009 Report on the Capacity, Demand, and Reserves in the ERCOT Region

Summer Summary



2009 Report on the Capacity, Demand, and Reserves in the ERCOT Region

Winter Summary

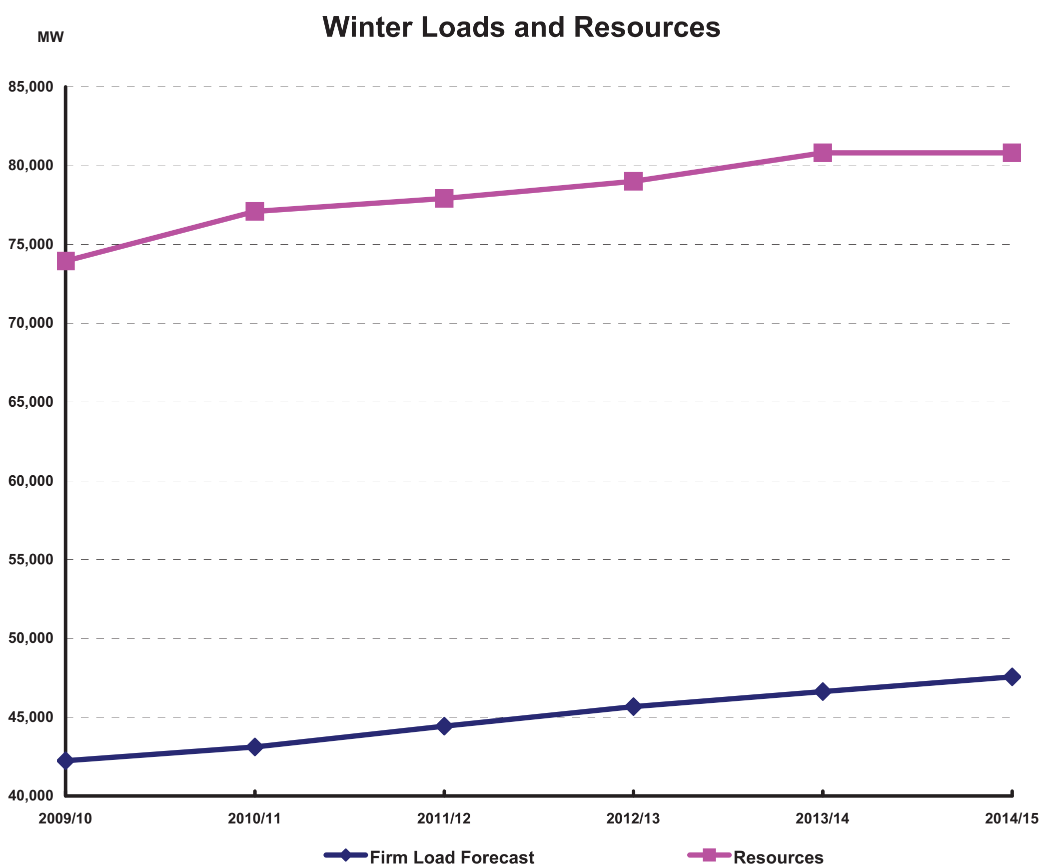
Load Forecast:	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Total Summer Peak Demand, MW	43,463	44,463	45,784	47,030	47,984	48,914
less LAARs Serving as Responsive Reserve, MW	1,115	1,115	1,115	1,115	1,115	1,115
less LAARs Serving as Non-Spinning Reserve, MW	0	0	0	0	0	0
less BULs, MW	0	0	0	0	0	0
less Energy Efficiency Programs (per HB3693)	110	242	242	242	242	242
Firm Load Forecast, MW	**42,238**	**43,106**	**44,427**	**45,673**	**46,627**	**47,557**

Resources:	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Installed Capacity, MW	62,863	62,863	62,863	62,863	62,863	62,863
Capacity from Private Networks, MW	5,843	5,848	5,850	5,850	5,850	5,850
Effective Load-Carrying Capability (ELCC) of Wind Generation, MW	708	708	708	708	708	708
RMR Units to be under Contract, MW	115	0	0	0	0	0
Operational Generation, MW	**69,529**	**69,419**	**69,421**	**69,421**	**69,421**	**69,421**
50% of Non-Synchronous Ties, MW	553	553	553	553	553	553
Switchable Units, MW	3,100	3,100	3,100	3,100	3,100	3,100
Available Mothballed Generation , MW	258	323	323	323	323	323
Planned Units (not wind) with Signed IA and Air Permit, MW	805	3,769	4,389	5,414	7,206	7,206
ELCC of Planned Wind Units with Signed IA, MW	16	89	132	190	211	211
Total Resources, MW	**74,260**	**77,252**	**77,917**	**79,001**	**80,813**	**80,813**
less Switchable Units Unavailable to ERCOT, MW	317	158	0	0	0	0
less Retiring Units, MW	0	0	0	0	0	0
Resources, MW	**73,943**	**77,094**	**77,917**	**79,001**	**80,813**	**80,813**
Reserve Margin	**75.1%**	**78.8%**	**75.4%**	**73.0%**	**73.3%**	**69.9%**
(Resources - Firm Load Forecast)/Firm Load Forecast						

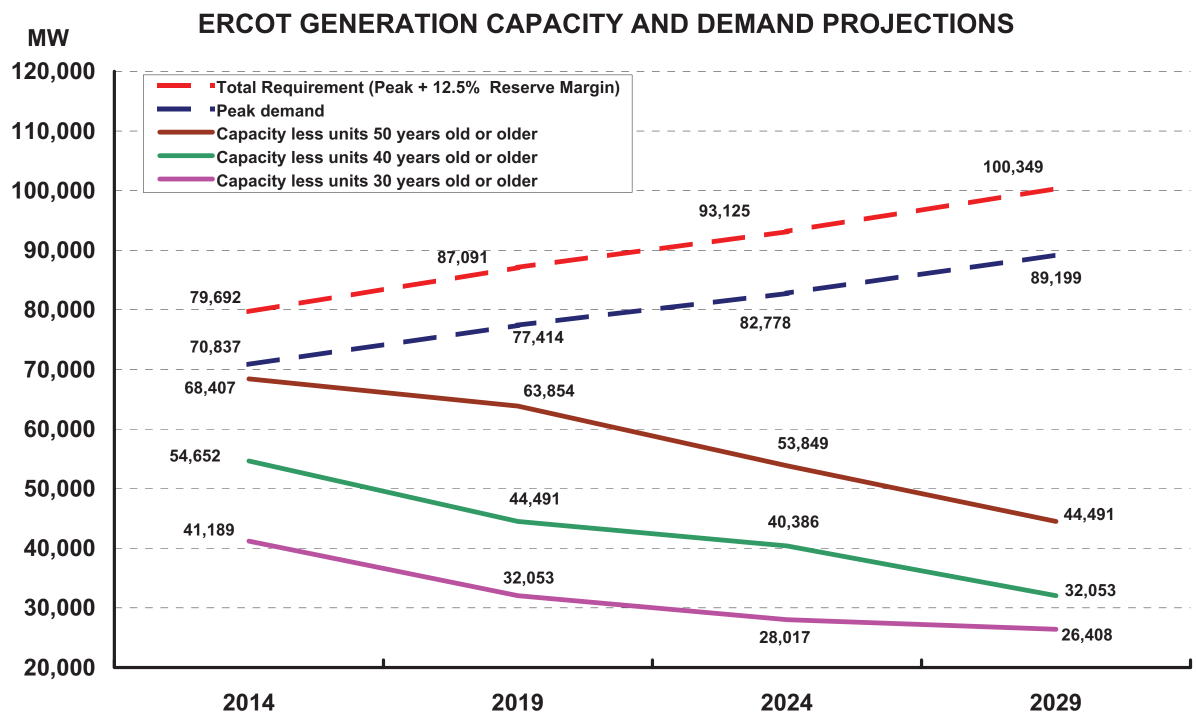
Other Potential Resources:	**8,118**	**16,154**	**25,785**	**29,001**	**31,328**	**32,934**
Mothballed Capacity , MW	6,882	7,332	7,332	7,332	7,332	7,332
50% of Non-Synchronous Ties, MW	553	553	553	553	553	553
Planned Units in Full Interconnection Study Phase, MW	683	8,269	17,900	21,116	23,443	25,049

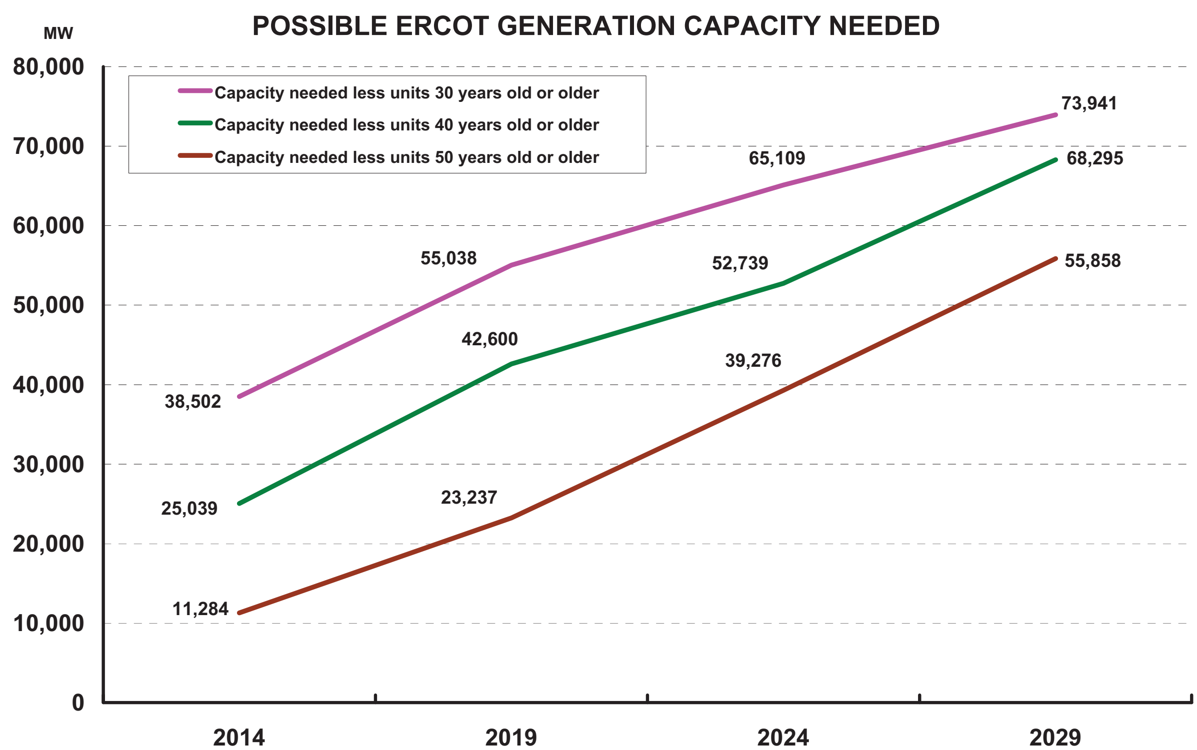
2009 Report on the Capacity, Demand, and Reserves in the ERCOT Region

Winter Summary



Long-Term Projections





STP Attachment 5

May 2010 Load Forecast and Reserve Margin Update

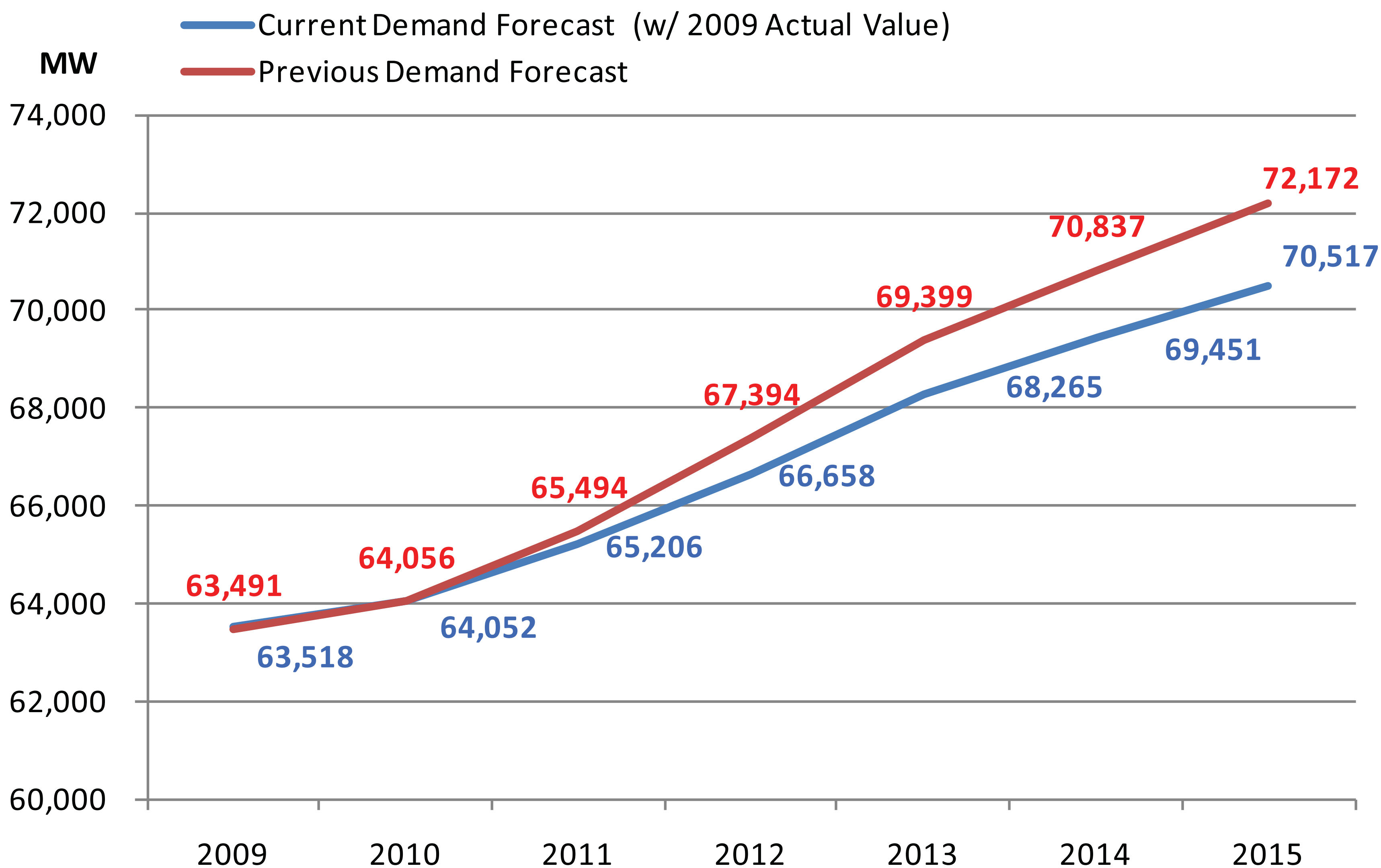
Dan Woodfin

Director, System Planning

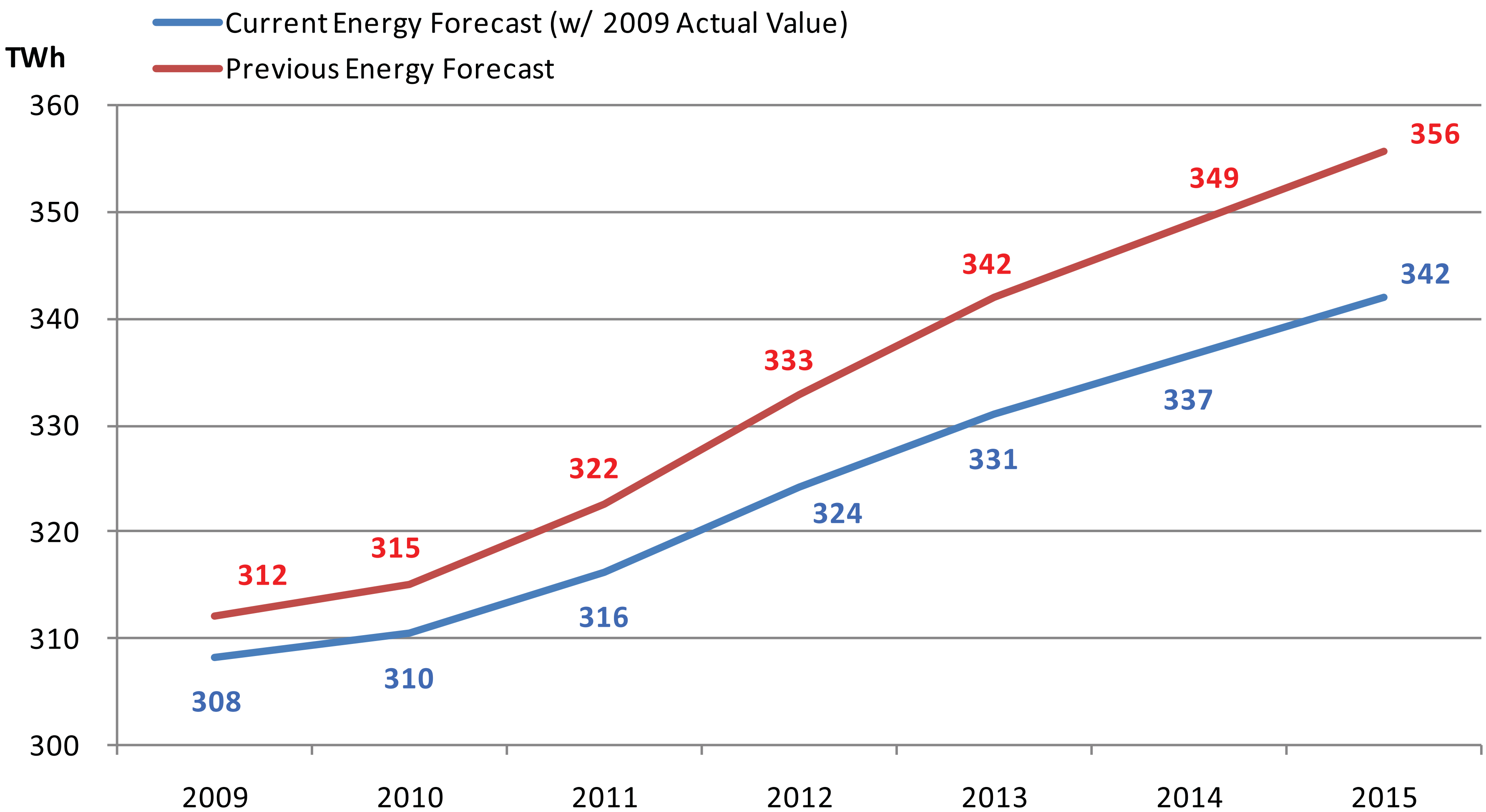
Board of Directors

May 18, 2010

Peak Demand Forecast



Energy Forecast



Resource Changes since December 2009 Update

- **New Generation (IAs, Air Permit, Verification)**

• Coleto Creek Unit 2	756
• Papalote Creek Wind (198MW nameplate)	17
• Panda Temple Power	1,300
	2,073

- **Cancelled Generation Projects**

– Sterling Energy Center (300 MW nameplate)	-26
– Lenorah Wind Project (251 MW nameplate)	-22
	-48

- **Mothballed Units**

– Valley 1,2 & 3	-1,069
– Tradinghouse 2	-787
– Spencer 4 (and 5 after 2010)	-122
– North Texas 1,2 & 3	-75
	-2,053

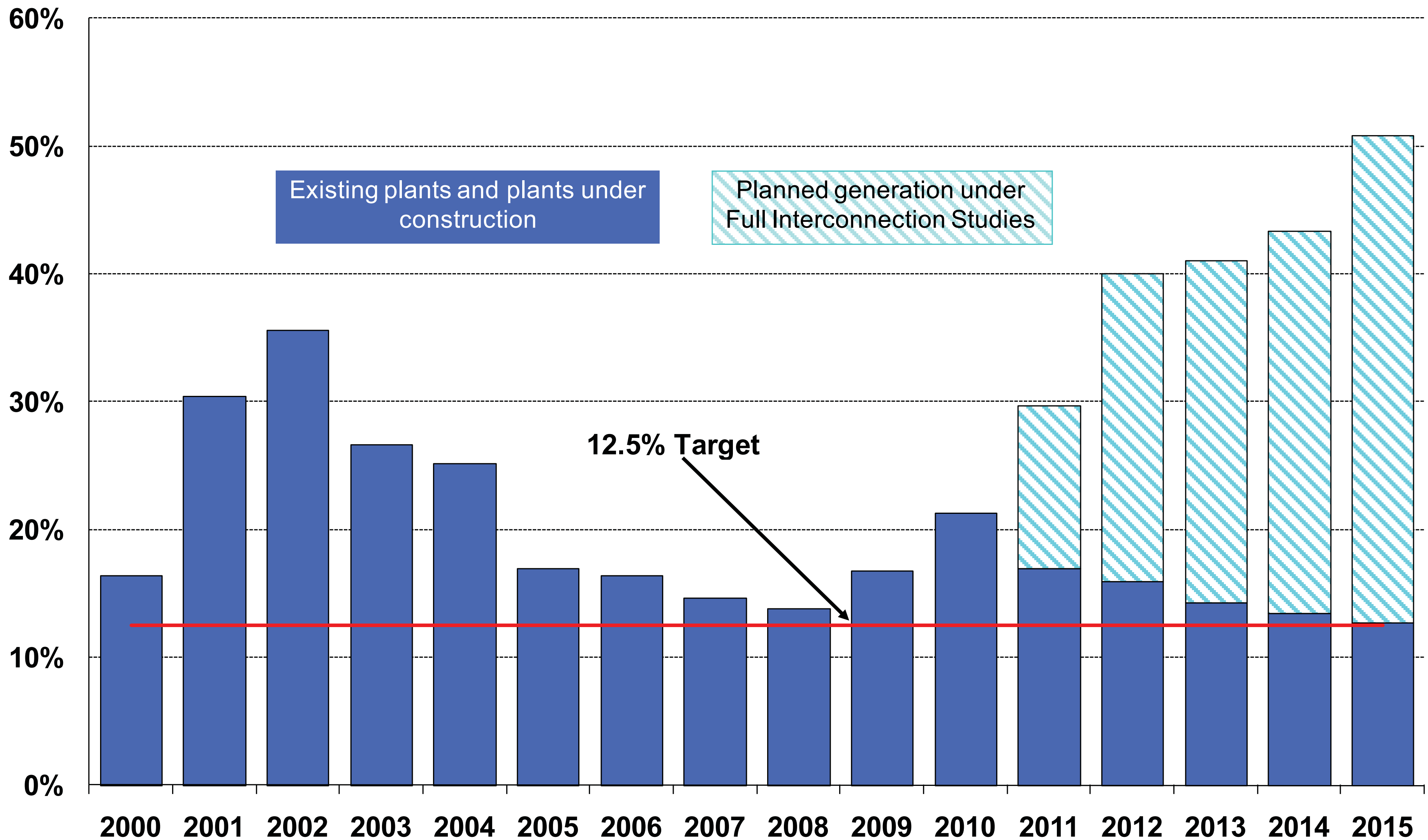
- **Changes in unit ratings, PUNs and mothballed unit return probabilities** -446

Reserve Margin Target

- **LOLE Study has not yet been completed**
  - Data access and quality issues
  - Model validation
  - Will finalize study and seek approvals prior to December CDR update

- **May 2010 CDR uses current reserve margin target (12.5%) and wind capacity value (8.7%)**

Reserve Margins



CDR Summary

2010 Report on the Capacity, Demand, and Reserves in the ERCOT Region

Summer Summary

Load Forecast:	2010	2011	2012	2013	2014	2015
Total Summer Peak Demand, MW	64,052	65,206	66,658	68,265	69,451	70,517
less LAARs Serving as Responsive Reserve, MW	1,062	1,062	1,062	1,062	1,062	1,062
less LAARs Serving as Non-Spinning Reserve, MW	0	0	0	0	0	0
less Emergency Interruptable Load Services	336	370	407	447	492	541
less BULs, MW	0	0	0	0	0	0
less Energy Efficiency Programs (per HB3693)	242	242	242	242	242	242
Firm Load Forecast, MW	**62,412**	**63,532**	**64,947**	**66,514**	**67,655**	**68,672**

Resources:	2010	2011	2012	2013	2014	2015
Installed Capacity, MW	66,228	64,372	64,372	64,372	64,372	64,372
Capacity from Private Networks, MW	4,803	4,803	4,803	4,803	4,803	4,803
Effective Load-Carrying Capability (ELCC) of Wind Generation, MW	793	793	793	793	793	793
RMR Units to be under Contract, MW	688	0	0	0	0	0
Operational Generation, MW	**72,512**	**69,968**	**69,968**	**69,968**	**69,968**	**69,968**
50% of Non-Synchronous Ties, MW	553	553	553	553	553	553
Switchable Units, MW	2,848	2,848	2,848	2,848	2,848	2,848
Available Mothballed Generation , MW	0	0	0	0	0	0
Planned Units (not wind) with Signed IA and Air Permit, MW	0	978	2,003	2,653	3,409	4,059
ELCC of Planned Wind Units with Signed IA, MW	0	30	43	95	115	115
Total Resources, MW	**75,913**	**74,377**	**75,415**	**76,117**	**76,893**	**77,543**
less Switchable Units Unavailable to ERCOT, MW	158	0	0	0	0	0
less Retiring Units, MW	0	0	0	0	0	0
Resources, MW	**75,755**	**74,377**	**75,415**	**76,117**	**76,893**	**77,543**
Reserve Margin	**21.4%**	**17.1%**	**16.1%**	**14.4%**	**13.7%**	**12.9%**
(Resources - Firm Load Forecast)/Firm Load Forecast						

Other Potential Resources:	553	13,691	21,252	23,402	25,813	31,757
Mothballed Capacity , MW	0	5,022	5,022	5,022	5,022	5,022
50% of Non-Synchronous Ties, MW	553	553	553	553	553	553
Planned Units in Full Interconnection Study Phase, MW	0	8,116	15,677	17,827	20,238	26,182

Questions?

STP Attachment 6

2008 Report on the Capacity, Demand, and Reserves in the ERCOT Region

Summer Summary (December Update)

Load Forecast:	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Total Summer Peak Demand, MW	65,222	66,283	67,654	68,932	70,408	71,678
less LAARs Serving as Responsive Reserve, MW	1,115	1,115	1,115	1,115	1,115	1,115
less LAARs Serving as Non-Spinning Reserve, MW	0	0	0	0	0	0
less BULs, MW	0	0	0	0	0	0
less Energy Efficiency Programs (per HB3693)	160	160	160	160	160	160
Firm Load Forecast, MW	**63,947**	**65,008**	**66,379**	**67,657**	**69,133**	**70,403**
Resources:	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Installed Capacity, MW	62,352	62,352	62,352	62,352	62,352	62,352
Capacity from Private Networks, MW	6,280	6,262	6,262	6,262	6,262	6,262
Effective Load-Carrying Capability (ELCC) of Wind Generation, MW	688	688	688	688	688	688
RMR Units under Contract, MW	0	0	0	0	0	0
Operational Generation, MW	**69,320**	**69,302**	**69,302**	**69,302**	**69,302**	**69,302**
50% of Non-Synchronous Ties, MW	553	553	553	553	553	553
Switchable Units, MW	2,848	2,848	2,848	2,848	2,848	2,848
Available Mothballed Generation , MW	555	848	848	848	848	848
Planned Units (not wind) with Signed IA and Air Permit, MW	1,038	5,174	5,174	6,099	7,891	7,891
ELCC of Planned Wind Units with Signed IA, MW	54	101	124	124	145	145
Total Resources, MW	**74,368**	**78,826**	**78,850**	**79,775**	**81,587**	**81,587**
less Switchable Units Unavailable to ERCOT, MW	317	0	0	0	0	0
less Retiring Units, MW	0	58	58	58	58	58
Resources, MW	**74,051**	**78,768**	**78,792**	**79,717**	**81,529**	**81,529**
Reserve Margin	**15.8%**	**21.2%**	**18.7%**	**17.8%**	**17.9%**	**15.8%**
(Resources - Firm Load Forecast)/Firm Load Forecast						

Other Potential Resources:	**6,318**	**15,665**	**24,798**	**32,155**	**34,561**	**35,334**
Mothballed Capacity , MW	4,314	4,314	4,314	4,314	4,314	4,314
50% of Non-Synchronous Ties, MW	553	553	553	553	553	553
Planned Units in Full Interconnection Study Phase, MW	1,451	10,798	19,931	27,288	29,694	30,467

STP Attachment 7

Conclusion

The indicators in this report present compelling evidence that the composition of the atmosphere and many fundamental measures of climate in the United States are changing. These changes include rising air and water temperatures, more heavy precipitation, and, over the last several decades, more frequent heat waves and intense Atlantic hurricanes. Assessment reports from the Intergovernmental Panel on Climate Change and the U.S. Global Change Research Program have linked many of these changes to increasing greenhouse gas emissions from human activities, which are also documented in this report.

Analysis of the indicators presented here suggests that these climate changes are affecting the environment in ways that are important for society and ecosystems. Sea levels are rising, snow cover is decreasing, glaciers are melting, and planting zones are shifting (see Summary of Key Findings on p. 4). Although the indicators in this report were developed from some of the most complete data sets currently available, they represent just a small sample of the growing portfolio of potential indicators. Considering that future warming projected for the 21st century is very likely to be greater than observed warming over the past century,[1] indicators of climate change should only become more clear, numerous, and compelling.

As new and more complete indicator data become available, EPA plans to update the indicators presented in this report and provide additional indicators that can more comprehensively document climate change and its effects. Identifying and analyzing indicators will improve our understanding of climate change, validate projections of future change, and, importantly, assist us in evaluating efforts to slow climate change and adapt to its effects. Looking ahead, EPA will continue to work in partnership with other agencies, organizations, and individuals to collect useful data and to craft informed policies and programs based on this knowledge.

STP Attachment 8

caller.com
CORPUS CHRISTI, TEXAS

Corpus Christi City Council to discuss Las Brisas water incentives

Council will meet on Tuesday

By Sara Foley

Originally published 01:33 p.m., March 26, 2010
Updated 02:08 p.m., March 26, 2010

CORPUS CHRISTI — The City Council will consider awarding the proposed Las Brisas Energy Center incentives for bringing jobs to the area.

Las Brisas is a proposed $3 billion power plant that would be fueled by petroleum coke, a leftover from oil refining. The project has generated heated debate in the community about its economic and environmental effects.

The power plant would be on Port of Corpus Christi land that's not in city limits, but depend on city water.

The incentives the council will consider Tuesday are water-related, City Councilwoman Chris Adler said. The details of the incentive request haven't been presented to the council and representatives from the company couldn't be reached Friday for comment.

The power plant's expected water needs have driven some of the debate on the issue.

The plant is expected to buy billions of gallons of untreated water from the city, although details of the contract haven't been finalized. According to the company's wastewater permit, an average daily flow of about 3.7 million gallons would flow into the Corpus Christi Inner Harbor. Most of the water would come from cooling tower processes.

The potential impact on the city's water supply has drawn some criticism from Las Brisas opponents, who have claimed the city plans to extend its pipeline specifically for the plant. City officials counter that the city will need the pipeline with or without Las Brisas. At its current growth rate, the city is expected to need more water by 2027. That date jumps to 2020 with the addition of the power plant.

Most on the council have said they would support Las Brisas if its air permit receives approval from the Texas Commission on Environmental Quality.

If the company receives permit approval, Adler said, she would support it however she could.

“I can’t imagine a more important thing to happen to the city right now than a $3 billion investment,” she said.

Two judges are expected to release their recommendation on the air permit application this month.

Then three agency commissioners would make the final decision on the air permit, which allows pollutants such as nitrogen oxides, particulate matter, sulfur and mercury to be emitted into the air.

The company could start construction once it receives the air permit.

Earlier this month, Nueces County commissioners voted 4-1 for $40 million in tax abatements for Las Brisas.

STP Attachment 9

caller.com
CORPUS CHRISTI, TEXAS

City Council to begin discussion on Garwood pipeline

By Denise Malan

Monday, December 7, 2009

CORPUS CHRISTI — The city is beginning discussions about when to build a new 40-mile water pipeline, a decision that will affect how much the project costs ratepayers.

Figures from the city show the rate for raw water could increase by 36 percent to nearly $1.20 per 1,000 gallons of water. The raw water charge is one of two categories on a water bill; the other is for treating the water.

The impact would be a 3 percent increase by 2030, when a large portion of the city's already existing water service debt is paid off.

The figures are based on an estimate of $165 million to build the pipeline in 2027. The estimate to build the pipeline now is $100 million.

City staff will present the estimates to the City Council today and begin a discussion on when the city should build the pipeline.

"We need to make sure we're providing that water at the best appropriate time — not too early so we have an overabundant supply but at the same time not waiting until we're under the gun and spending extra dollars to meet an unreasonable timeline," Assistant City Manager Oscar Martinez said.

The council could set a trigger to begin the two-year pipeline construction, such as when demand reaches about 80 percent of supply. The current demand is about 65 percent.

The city has received tentative approval for an $8 million loan from the Texas Water Development Board to plan the project. Final approval is expected next month.

The pipeline would carry water from the Lower Colorado River to Lake Texana, where it could then flow through the existing Mary Rhodes Pipeline to Corpus Christi. The project is known informally as the Garwood pipeline because the city bought water rights from the Garwood Irrigation Co.

The planning and permitting phase is expected to last about two years. Mayor Joe

Adame has made planning the pipeline a top priority, saying the project must be ready for construction when Corpus Christi needs it.

At the current growth rate, the city is expected to need more water by 2027. That estimated date jumps to 2020 with the addition of Las Brisas Energy Center, a planned power plant on the Corpus Christi Inner Harbor that would buy billions of gallons of untreated water from the city. Details of Las Brisas' contract have not been finalized.

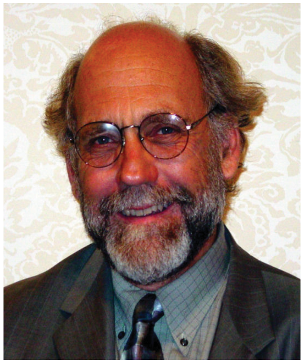
Las Brisas opponents have criticized the city, saying officials want to build the pipeline specifically for the plant. Officials counter that the city will need the pipeline with or without Las Brisas.

The city bought the Lower Colorado water rights in 1997. It has rights to 35,000 acre feet annually, which some fear could be lost if the city doesn't tap into it sooner rather than later. The city's system currently uses about 175,000 acre feet.

STP Attachment 10

Texas Staff Member Bio's

Tom "Smitty" Smith, Director of Public Citizen's Texas Office



Smitty has served as state director of Public Citizen since 1985 and serves on the boards of Clean Water Action, the Texas Wind Power Coalition, Texans for Public Justice, Campaigns for People, the Clean Energy Project of CEERT, a nature preserve, and a solar energy company. He has recently received the Thomas Paine award from Campaigns for People, 2001 *Austin Chronicle*'s critics choice award for "Best People's Lobbyist" as well as an U.S. EPA "Environmental Excellence Award."

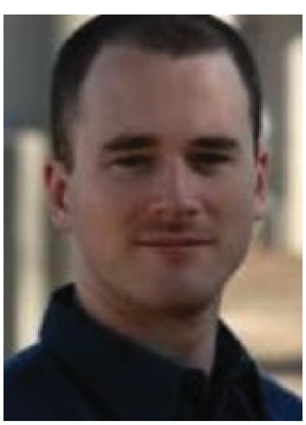
Public Citizen is a consumer and environmental group active in issues concerning energy, environment, ethics and campaign finance reforms, trade agreements with Mexico and other countries, and urban sprawl. During his tenure at Public Citizen, Smitty has served on four commissions that looked at the future of the utility industry in Texas and has testified on more that 100 occasions on environmental and energy policy. His proudest accomplishments are: helping to pass laws requiring Texas to develop 2,000 MW of renewable energy; and creating the Texas Emissions Reductions Plan, which reduces emissions from TexasÃ¢â‚¬â„¢ dirtiest diesels, gives incentives for purchasing the cleanest new cars and trucks, requires political subdivisions to reduce their energy use by 25% over the next 5 years and requires all new homes or commercial buildings to meet new tough energy use standards.

Smitty hails from Illinois. He graduated from Valparaiso University in northern Indiana and became a Texan by choice in 1974. Before joining Public Citizen, he worked as a legal aid, as a legislative aide, directed the Houston Foodbank and ran an anti-hunger advocacy program.

David Power, Deputy Director

David joined Public Citizen in January 2009 and is the lead solar and renewables program manager. He ran Green Planet Energy, an energy efficiency consulting company for small and medium businesses. He was the Senior Vice President of Network and Technologies for Reliant Energy a Houston based retail electric provider. He also co founded several hi-tech companies and was Chief Technology Officer and VP of Operations at Insync Internet Services. He worked at the Houston Post for 15 years and designed the electronic picture desk, moving the newsroom from film based photography to digital image storage and cataloging along with desk top publishing systems.

Ryan Rittenhouse, Coal Block Assistant



Ryan started working for Public Citizen in March of 2008. His current focus is on the coal block campaign, working to halt the construction of new coal-fired power plants in Texas and throughout the country. He also works to improve the websites and public interaction with the organization through multi-media. He moved to Austin in September of 2007 and worked in the film industry there for 5 months before joining Public Citizen. Ryan has a background in film and theater work, carpentry, environmental activism and history. He graduated from Allegheny College in Meadville, PA with a BA in Communication Arts and worked with Ohio Citizen Action in Cleveland, OH, his home town. He is a member of the Sea Shepherd Conservation Society and sailed with them for 9 months, protecting marine animals and environments.

STP Attachment 11

Bill Summary & Status
111th Congress (2009 - 2010)
H.R.5019
All Information

H.R.5019
Title: Home Star Energy Retrofit Act of 2010
Sponsor: Rep Welch, Peter [VT] (introduced 4/14/2010) Cosponsors (44)
Related Bills: H.RES.1329, S.3177
Latest Major Action: 5/7/2010 Referred to Senate committee. Status: Received in the Senate and Read twice and referred to the Committee on Finance.
House Reports: 111-469 Part 1

Jump to: Summary, Major Actions, All Actions, Titles, Cosponsors, Committees, Related Bill Details, Amendments

SUMMARY AS OF:
4/14/2010--Introduced.

Home Star Energy Retrofit Act of 2010 - Requires the Secretary of Energy to establish: (1) the Home Star Retrofit Rebate Program to provide rebates to contractors to be passed through as discounts to homeowners who retrofit their homes to achieve energy savings; (2) a Federal Rebate Processing System to enable rebate aggregators to submit claims for reimbursement; and (3) a national retrofit website and public information campaign that provide information on the Program.

Requires the Secretary to: (1) develop a network of rebate aggregators that can facilitate the delivery of rebates to reimburse participating contractors and vendors for discounts provided to homeowners for energy efficiency retrofit work; (2) ensure that rebate aggregation services are available to all homeowners at the lowest reasonable cost; and (3) develop guidelines for states to allow utilities participating as rebate aggregators to count the energy savings from their participation toward state-level energy saving targets. Sets forth eligibility criteria for, and responsibilities of, rebate aggregators.

Establishes: (1) a Silver Star Home Energy Retrofit Program to award rebates during the first year after this Act's enactment to reimburse participating contractors and vendors for discounts provided to homeowners for retrofit work that installs specified energy saving measures, including air-sealing and insulation measures, duct seal or replacement, window or door replacement, heating or cooling system replacement, and water heater replacement; and (2) a Gold Star Home Energy Retrofit Program to award rebates to reimburse participating accredited contractors and vendors for retrofit work that achieves whole home energy savings.

Sets forth provisions concerning: (1) the amount of the rebates (up to $3,000 per home for Silver Star rebates or $8,000 per home for Gold Star rebates); and (2) the treatment of rebates for tax purposes (excluded from taxable income).

Requires states that receive funding under this Act to submit to the Secretary plans to implement quality assurance programs that cover residential energy efficiency retrofit work sponsored or provided under this Act.

Requires the Secretary to establish a Home Star Energy Efficiency Loan Program to make funds available to states to support financial assistance provided by qualified financing entities for qualifying energy saving measures under the Silver Star or Gold Star programs.

MAJOR ACTIONS:

4/14/2010	Introduced in House
4/29/2010	Reported (Amended) by the Committee on Energy and Commerce. H. Rept. 111-469, Part I.
4/29/2010	Committee on Ways and Means discharged.
5/3/2010	Committee on Oversight and Government discharged.
5/6/2010	Passed/agreed to in House: On passage Passed by the Yeas and Nays: 246 - 161 (Roll no. 255).
5/7/2010	Referred to Senate committee: Received in the Senate and Read twice and referred to the Committee on Finance.

ALL ACTIONS:

4/14/2010:
Referred to the Committee on Energy and Commerce, and in addition to the Committee on Ways and Means, for a period to be subsequently determined by the Speaker, in each case for consideration of such provisions as fall within the jurisdiction of the committee concerned.
4/14/2010:
Referred to House Energy and Commerce
3/18/2010:

Hearings Held by the Subcommittee on Energy and Environment Prior to Introduction.

3/24/2010:
Subcommittee Consideration and Mark-up Session Held and Forwarded to Full Committee by the Subcommittee on Energy and Environment Prior to Introduction amended by voice vote.

4/15/2010:
Committee Consideration and Mark-up Session Held.

4/15/2010:
Ordered to be Reported (Amended) by the Yeas and Nays: 30 - 17.

4/14/2010:
Referred to House Ways and Means

4/29/2010 7:00pm:
Reported (Amended) by the Committee on Energy and Commerce. H. Rept. 111-469, Part I.

4/29/2010:
Referred sequentially to the House Committee on Oversight and Government Reform for a period ending not later than May 3, 2010 for consideration of such provisions of the bill and amendment as fall within the jurisdiction of that committee pursuant to clause 1(m), rule X.

4/29/2010 7:03pm:
Committee on Ways and Means discharged.

5/3/2010 12:09pm:
Committee on Oversight and Government discharged.

5/3/2010 12:09pm:
Placed on the Union Calendar, Calendar No. 268.

5/5/2010 5:22pm:
Rules Committee Resolution H. Res. 1329 Reported to House. Rule provides for consideration of H.R. 5019 with 1 hour of general debate. Previous question shall be considered as ordered without intervening motions except motion to recommit with or without instructions. Measure will be considered read. Specified amendments are in order. The committee amendment in the nature of a substitute shall be considered as read. All points of order against the committee amendment in the nature of a substitute are waived except those arising under clause 10 of rule XXI.

5/6/2010 11:53am:
Rule H. Res. 1329 passed House.

5/6/2010 12:12pm:
Considered under the provisions of rule H. Res. 1329. (consideration: CR H3216-3248)

5/6/2010 12:13pm:
Rule provides for consideration of H.R. 5019 with 1 hour of general debate. Previous question shall be considered as ordered without intervening motions except motion to recommit with or without instructions. Measure will be considered read. Specified amendments are in order. The committee amendment in the nature of a substitute shall be considered as read. All points of order against the committee amendment in the nature of a substitute are waived except those arising under clause 10 of rule XXI.

5/6/2010 12:14pm:
House resolved itself into the Committee of the Whole House on the state of the Union pursuant to H. Res. 1329 and Rule XVIII.

5/6/2010 12:14pm:
The Speaker designated the Honorable Donna F. Edwards to act as Chairwoman of the Committee.

5/6/2010 12:15pm:
GENERAL DEBATE - The Committee of the Whole proceeded with one hour of general debate on H.R. 5019.

5/6/2010 1:12pm:
H.AMDT.627 Amendment (A001) offered by Mr. Markey (MA). (consideration: CR H3234-3237; text : CR H3234-3237)
Amendment strikes the provision that permits financing entities to use funds repaid by participants to provide assistance to additional participants.

5/6/2010 1:12pm:
DEBATE - Pursuant to the provisions of H.Res. 1329, the Committee of the Whole proceeded with 20 minutes of debate on the Markey(MA) amendment.

5/6/2010 1:19pm:
H.AMDT.627 On agreeing to the Markey (MA) amendment (A001) Agreed to by voice vote.

5/6/2010 1:19pm:
H.AMDT.628 Amendment (A002) offered by Mr. Barton (TX). (consideration: CR H3237-3239, H3243; text: CR H3237)
Amendment sought to strike the provision that permits financing entities to use funds repaid by participants to provide assistance to additional participants.

5/6/2010 1:20pm:
DEBATE - Pursuant to the provisions of H.Res. 1329, the Committee of the Whole proceeded with 10 minutes of debate on the Barton (TX) amendment.

5/6/2010 1:32pm:
POSTPONED PROCEEDINGS - At the conclusion of debate on Barton (TX) amendment, the Chair put the question on adoption of the amendment and by voice vote, announced that the ayes had prevailed. Mr. Markey(MA) demanded a recorded vote and the Chair postponed further proceedings on the question of adoption of the amendment until later in the legislative day.

5/6/2010 1:32pm:
H.AMDT.629 Amendment (A003) offered by Mr. Nye. (consideration: CR H3239; text: CR H3239)
Amendment adds Armed Forces exchange services as qualified rebate aggregators.

5/6/2010 1:33pm:
DEBATE - Pursuant to the provisions of H.Res. 1329, the Committee of the Whole proceeded with 10 minutes of debate on the Nye amendment.

5/6/2010 1:35pm:
H.AMDT.629 On agreeing to the Nye amendment (A003) Agreed to by voice vote.

5/6/2010 1:35pm:
H.AMDT.630 Amendment (A004) offered by Mr. Burgess. (consideration: CR H3239-3240, H3243-3244; text: CR H3239)
Amendment sought to strike the public information campaign (section 109) from the bill and strike the campaign's $12 million authorization.

5/6/2010 1:36pm:

DEBATE - Pursuant to the provisions of H.Res. 1329, the Committee of the Whole proceeded with 10 minutes of debate on the Burgess amendment.

5/6/2010 1:46pm:
POSTPONED PROCEEDINGS - At the conclusion of debate on Burgess amendment, the Chair put the question on adoption of the amendment and by voice vote, announced that the noes had prevailed. Mr. Burgess demanded a recorded vote and the Chair postponed further proceedings on the question of adoption of the amendment until later in the legislative day.

5/6/2010 1:46pm:
H.AMDT.631 Amendment (A005) offered by Mr. Deutch. (consideration: CR H3240-3241; text: CR H3240)
An amendment numbered 5 printed in House Report 111-475 to require the Secretary to ensure that a home in a disaster area is not denied assistance under the Home Star program solely because there is no equipment or system to replace due to the disaster.

5/6/2010 1:47pm:
DEBATE - Pursuant to the provisions of H.Res. 1329, the Committee of the Whole proceeded with 10 minutes of debate on the Deutch amendment.

5/6/2010 1:50pm:
H.AMDT.631 On agreeing to the Deutch amendment (A005) Agreed to by voice vote.

5/6/2010 1:50pm:
H.AMDT.632 Amendment (A006) offered by Mr. Flake. (consideration: CR H3241; text: CR H3241)
Amendment prohibits any of the funds authorized in the bill from being used for a Congressional earmark.

5/6/2010 1:51pm:
DEBATE - Pursuant to the provisions of H.Res. 1329, the Committee of the Whole proceeded with 10 minutes of debate on the Flake amendment.

5/6/2010 1:52pm:
H.AMDT.632 On agreeing to the Flake amendment (A006) Agreed to by voice vote.

5/6/2010 1:53pm:
H.AMDT.633 Amendment (A007) offered by Mr. Garrett (NJ). (consideration: CR H3241-3242; text: CR H3241)
Amendment requires a GAO study of how much money and energy has been saved by American consumers as a result of the increased energy efficiency measures undertaken in title I of the bill (the Silver Star and Gold Star programs), and whether the savings are greater than the cost of the implementation of title I of the bill.

5/6/2010 1:53pm:
DEBATE - Pursuant to the provisions of H.Res. 1329, the Committee of the Whole proceeded with 10 minutes of debate on the Garrett (NJ) amendment.

5/6/2010 1:59pm:
H.AMDT.633 On agreeing to the Garrett (NJ) amendment (A007) Agreed to by voice vote.

5/6/2010 2:00pm:
H.AMDT.634 Amendment (A008) offered by Mrs. Bachmann. (consideration: CR H3242-3243; text: CR H3242)
Amendment requirs the Department of Energy's Inspector General to submit a report to Congress identifying incidents of waste, fraud and abuse associated with the programs created by the bill. The amendment requires the report to include recommendations to prevent additional waste, fraud and abuse.

5/6/2010 2:00pm:
DEBATE - Pursuant to the provisions of H.Res. 1329, the Committee of the Whole proceeded with 10 minutes of debate on the Bachmann amendment.

5/6/2010 2:06pm:
H.AMDT.634 On agreeing to the Bachmann amendment (A008) Agreed to by voice vote.

5/6/2010 2:06pm:
UNFINISHED BUSINESS - The Chair announced that the unfinished business was on the question of adoption of amendments which had been previously debated and on which further proceedings had been postponed.

5/6/2010 2:34pm:
H.AMDT.628 On agreeing to the Barton (TX) amendment (A002) Failed by recorded vote: 180 - 237 (Roll no. 252).

5/6/2010 2:42pm:
H.AMDT.630 On agreeing to the Burgess amendment (A004) Failed by recorded vote: 190 - 228 (Roll no. 253).

5/6/2010 2:43pm:
The House rose from the Committee of the Whole House on the state of the Union to report H.R. 5019.

5/6/2010 2:43pm:
The previous question was ordered pursuant to the rule. (consideration: CR H3244)

5/6/2010 2:43pm:
The House adopted the amendment in the nature of a substitute as agreed to by the Committee of the Whole House on the state of the Union. (text: CR H3227-3234)

5/6/2010 2:44pm:
Mr. Barton (TX) moved to recommit with instructions to Energy and Commerce. (consideration: CR H3244-3245; text: CR H3244-3245)

5/6/2010 2:51pm:
DEBATE - The House proceeded with 10 minutes of debate on the Barton (TX) motion to recommit with instructions. The instructions contained in the motion seek to report the same back to the House forthwith with amendments to strike various provisions in the bill and insert a section entitled "SEC. 301. SUNSET. - The provisions of this Act shall be suspended and shall not apply if this Act will have a negative net effect on the national budget deficit of the United States."

5/6/2010 3:02pm:
The previous question on the motion to recommit with instructions was ordered without objection. (consideration: CR H3246-3247)

5/6/2010 3:36pm:
On motion to recommit with instructions Agreed to by the Yeas and Nays: 346 - 68 (Roll no. 254).

5/6/2010 3:37pm:
H.AMDT.635 Amendment (A009) offered by Mr. Waxman. (consideration: CR H3247-3248; text: CR H3247-3248)
See Barton (TX) Motion to Recommit for description.

5/6/2010 3:37pm:
H.AMDT.635 On agreeing to the Waxman amendment (A009) Agreed to by voice vote.

5/6/2010 3:44pm:

On passage Passed by the Yeas and Nays: 246 - 161 (Roll no. 255).

5/6/2010 3:44pm:
Motion to reconsider laid on the table Agreed to without objection.

5/7/2010:
Received in the Senate and Read twice and referred to the Committee on Finance.

TITLE(S): (*italics indicate a title for a portion of a bill*)

- SHORT TITLE(S) AS INTRODUCED:
  Home Star Energy Retrofit Act of 2010
- SHORT TITLE(S) AS REPORTED TO HOUSE:
  Home Star Energy Retrofit Act of 2010
- SHORT TITLE(S) AS PASSED HOUSE:
  Home Star Energy Retrofit Act of 2010
- OFFICIAL TITLE AS INTRODUCED:
  To provide for the establishment of the Home Star Retrofit Rebate Program, and for other purposes.

COSPONSORS(44), ALPHABETICAL [followed by Cosponsors withdrawn]: (Sort: by date)

Rep Berkley, Shelley [NV-1] - 4/22/2010	Rep Bishop, Timothy H. [NY-1] - 4/28/2010
Rep Braley, Bruce L. [IA-1] - 4/26/2010	Rep Capps, Lois [CA-23] - 4/22/2010
Rep Cardoza, Dennis A. [CA-18] - 4/14/2010	Rep Carnahan, Russ [MO-3] - 4/22/2010
Rep Carney, Christopher P. [PA-10] - 4/28/2010	Rep Connolly, Gerald E. "Gerry" [VA-11] - 4/28/2010
Rep Courtney, Joe [CT-2] - 4/22/2010	Rep Doyle, Michael F. [PA-14] - 4/28/2010
Rep Ehlers, Vernon J. [MI-3] - 4/14/2010	Rep Grijalva, Raul M. [AZ-7] - 4/22/2010
Rep Hall, John J. [NY-19] - 4/22/2010	Rep Hare, Phil [IL-17] - 4/26/2010
Rep Hastings, Alcee L. [FL-23] - 4/22/2010	Rep Himes, James A. [CT-4] - 4/26/2010
Rep Hinchey, Maurice D. [NY-22] - 4/26/2010	Rep Hirono, Mazie K. [HI-2] - 4/28/2010
Rep Holt, Rush D. [NJ-12] - 4/22/2010	Rep Honda, Michael M. [CA-15] - 4/22/2010
Rep Inslee, Jay [WA-1] - 4/22/2010	Rep Jackson, Jesse L., Jr. [IL-2] - 4/28/2010
Rep Langevin, James R. [RI-2] - 4/22/2010	Rep Loebsack, David [IA-2] - 4/22/2010
Rep Markey, Edward J. [MA-7] - 4/14/2010	Rep Matsui, Doris O. [CA-5] - 4/28/2010
Rep McGovern, James P. [MA-3] - 4/22/2010	Rep McNerney, Jerry [CA-11] - 4/26/2010
Rep Murphy, Patrick J. [PA-8] - 4/28/2010	Rep Murphy, Scott [NY-20] - 4/22/2010
Rep Norton, Eleanor Holmes [DC] - 4/28/2010	Rep Perriello, Thomas S.P. [VA-5] - 4/28/2010
Rep Pierluisi, Pedro R. [PR] - 4/22/2010	Rep Pingree, Chellie [ME-1] - 4/22/2010
Rep Polis, Jared [CO-2] - 4/28/2010	Rep Richardson, Laura [CA-37] - 4/28/2010
Rep Ryan, Tim [OH-17] - 4/22/2010	Rep Sarbanes, John P. [MD-3] - 4/22/2010
Rep Schakowsky, Janice D. [IL-9] - 4/26/2010	Rep Scott, David [GA-13] - 4/28/2010
Rep Sutton, Betty [OH-13] - 4/22/2010	Rep Van Hollen, Chris [MD-8] - 4/22/2010
Rep Waxman, Henry A. [CA-30] - 4/14/2010	Rep Weiner, Anthony D. [NY-9] - 4/22/2010

COMMITTEE(S):

Committee/Subcommittee:	**Activity:**
House Energy and Commerce	Referral, Markup, Reporting
Subcommittee on Energy and Environment	Hearings, Markup
House Ways and Means	Referral, Discharged
House Oversight and Government Reform	Referral, Discharged
Senate Finance	Referral, In Committee

RELATED BILL DETAILS: (additional related bills may be indentified in Status)

Bill:	**Relationship:**
H.RES.1329	Rule related to H.R.5019 in House
S.3177	Related bill identified by CRS

AMENDMENT(S):

1. H.AMDT.627 to H.R.5019 Amendment strikes the provision that permits financing entities to use funds repaid by participants to provide assistance to additional participants.

Sponsor: Rep Markey, Edward J. [MA-7] (introduced 5/6/2010) **Cosponsors** (None)
Latest Major Action: 5/6/2010 House amendment agreed to. Status: On agreeing to the Markey (MA) amendment (A001) Agreed to by voice vote.

2. H.AMDT.628 to H.R.5019 Amendment sought to strike the provision that permits financing entities to use funds repaid by participants to provide assistance to additional participants.
Sponsor: Rep Barton, Joe [TX-6] (introduced 5/6/2010) **Cosponsors** (None)
Latest Major Action: 5/6/2010 House amendment not agreed to. Status: On agreeing to the Barton (TX) amendment (A002) Failed by recorded vote: 180 - 237 (Roll no. 252).

3. H.AMDT.629 to H.R.5019 Amendment adds Armed Forces exchange services as qualified rebate aggregators.
Sponsor: Rep Nye, Glenn C. [VA-2] (introduced 5/6/2010) **Cosponsors** (None)
Latest Major Action: 5/6/2010 House amendment agreed to. Status: On agreeing to the Nye amendment (A003) Agreed to by voice vote.

4. H.AMDT.630 to H.R.5019 Amendment sought to strike the public information campaign (section 109) from the bill and strike the campaign's $12 million authorization.
Sponsor: Rep Burgess, Michael C. [TX-26] (introduced 5/6/2010) **Cosponsors** (None)
Latest Major Action: 5/6/2010 House amendment not agreed to. Status: On agreeing to the Burgess amendment (A004) Failed by recorded vote: 190 - 228 (Roll no. 253).

5. H.AMDT.631 to H.R.5019 An amendment numbered 5 printed in House Report 111-475 to require the Secretary to ensure that a home in a disaster area is not denied assistance under the Home Star program solely because there is no equipment or system to replace due to the disaster.
Sponsor: Rep Deutch, Theodore E. [FL-19] (introduced 5/6/2010) **Cosponsors** (None)
Latest Major Action: 5/6/2010 House amendment agreed to. Status: On agreeing to the Deutch amendment (A005) Agreed to by voice vote.

6. H.AMDT.632 to H.R.5019 Amendment prohibits any of the funds authorized in the bill from being used for a Congressional earmark.

Sponsor: Rep Flake, Jeff [AZ-6] (introduced 5/6/2010) **Cosponsors** (None)
Latest Major Action: 5/6/2010 House amendment agreed to. Status: On agreeing to the Flake amendment (A006) Agreed to by voice vote.

7. H.AMDT.633 to H.R.5019 Amendment requires a GAO study of how much money and energy has been saved by American consumers as a result of the increased energy efficiency measures undertaken in title I of the bill (the Silver Star and Gold Star programs), and whether the savings are greater than the cost of the implementation of title I of the bill.
Sponsor: Rep Garrett, Scott [NJ-5] (introduced 5/6/2010) **Cosponsors** (None)
Latest Major Action: 5/6/2010 House amendment agreed to. Status: On agreeing to the Garrett (NJ) amendment (A007) Agreed to by voice vote.

8. H.AMDT.634 to H.R.5019 Amendment requires the Department of Energy's Inspector General to submit a report to Congress identifying incidents of waste, fraud and abuse associated with the programs created by the bill. The amendment requires the report to include recommendations to prevent additional waste, fraud and abuse.
Sponsor: Rep Bachmann, Michele [MN-6] (introduced 5/6/2010) **Cosponsors** (None)
Latest Major Action: 5/6/2010 House amendment agreed to. Status: On agreeing to the Bachmann amendment (A008) Agreed to by voice vote.

9. H.AMDT.635 to H.R.5019 See Barton (TX) Motion to Recommit for description.
Sponsor: Rep Waxman, Henry A. [CA-30] (introduced 5/6/2010) **Cosponsors** (None)
Latest Major Action: 5/6/2010 House amendment agreed to. Status: On agreeing to the Waxman amendment (A009) Agreed to by voice vote.

STP Attachment 12

Rulemaking to Relating to the Goal for Renewable Energy

Project #35792

Summary

The purpose of this project is to modify the Renewable Portfolio Standard to include renewable energy credits (RECs) specifically for renewable energy technologies other than those that use wind as a source of power under the Public Utility Regulatory Act (PURA) §39.904, Goal for Renewable Energy. Additionally, this project seeks to simplify registration requirements for owners of distributed processing with capacity at or below two megawatts.

Project Status/Schedule

A strawman (see "Documents Available", below) has been filed for review and comment by interested parties. The strawman proposes to modify PUC Substantive Rules §25.109, §25.172 and §25.211. The comment period for the strawman has expired.
A workshop on this project was held on March 31. Presentations made at that time can be downloaded from "Documents Available" below.
PLEASE NOTE: HEARING AND NEW PROJECT SCHEDULE: In the May 27 Open Meeting, the commissioners directed staff to conduct a hearing under this project and 37623 (Proceeding to amend Energy Efficiency rules) to explore options to incent growth of distributed renewable generation. The hearing will be held at 10:00 A.M. on Wednesday, June 30,at the PUC in the Commissioners' Hearing Room, 7th Floor, 1701 N. Congress Avenue, Austin, TX.

Staff Assigned

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Documents Available	Download
ERCOT Implementation Analysis (* pdf)	(.ppt)
Recurrent Energy (* pdf)	
Virtus Energy (* pdf)	
SunPower (* pdf)	(.ppt)
Texas Solid Waste Association (* pdf)	(.ppt)
Updated Workshop Agenda - March 31, 2010 (* pdf)	35792ws.doc
Strawman filed December 21, 2009 (* pdf)	Strawman_122009.doc

Last Updated: 06/04/10

* PDF files require the use of the Adobe Acrobat Reader. Down load a free copy here.

Call the Assistance Hot Line 1-888-782-8477 or File a Complaint Online

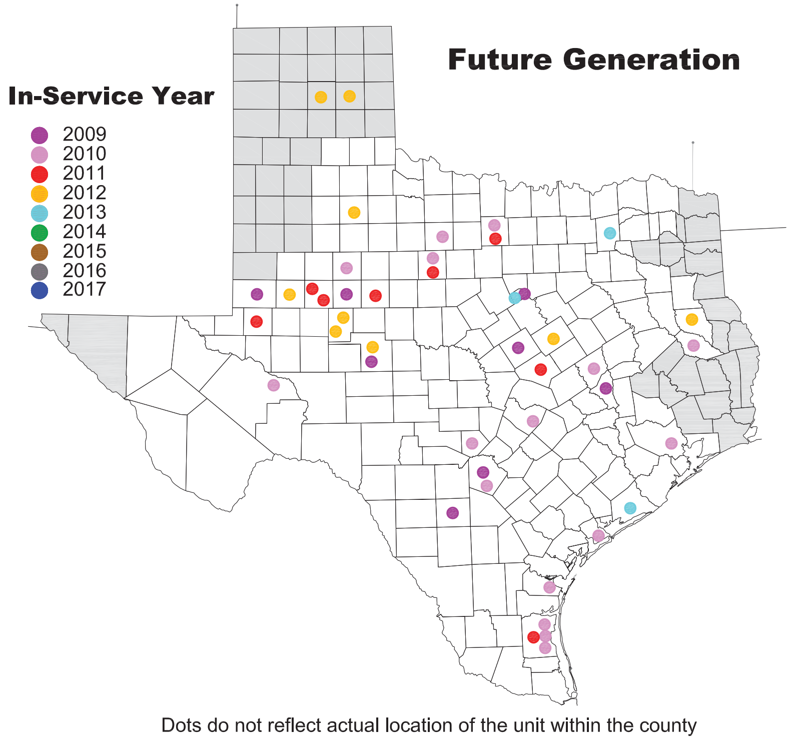
STP Attachment 13

Report on Existing and Potential Electric System Constraints and Needs

December, 2009

4.2 Future Generation

ERCOT has received interconnection requests for proposed generation having aggregate nameplate capacity over 79,000 MW. Of this capacity, over 20,000 MW is public and is shown on the map to the right.



The following table shows the interconnection requests for proposed capacity by fuel type.

ACTIVE GENERATION INTERCONNECTION REQUESTS BY FUEL TYPE (MW)			
Fuel	Non-Public	Public	Total
Gas-CC	13,096	3,881	16,977
Gas-CT	650	527	1,177
Nuclear	0	5,986	5,986
Coal	3,712	2,958	6,670
Wind	37,509	7,092	44,601
Solar	1,095	0	1,095
Biomass	108	145	253
Other	2,326	0	2,326
Total	58,496	20,589	79,085

The following table shows the requests for new generation in ERCOT between November 2008 and September 2009.

GENERATION INTERCONNECTION REQUEST ACTIVITY IN 2009						
FUEL	SCREENING STUDIES REQUESTED		INTERCONNECTION STUDIES REQUESTED		INTERCONNECTION AGREEMENTS SIGNED	
	Number	MW	Number	MW	Number	MW
Coal	1	15	1	1,200	1	263
Gas-CC	2	1,279	3	1,226	1	50
Gas-CT	0	0	2	600	11	1,930
Wind	48	14,447	35	11,771	0	0
Solar	17	1,095	4	459	0	0
Other	5	1,184	0	0	0	0
Total	73	18,020	45	15,256	13	2,243
Projects may appear in more than one category						

Continued load growth, a vibrant wholesale market, and renewal of the federal production tax credit for renewable generation continue to attract merchant plant developers to the Texas market, resulting in a high volume of interconnection requests. However, there is much uncertainty associated with many of the proposed interconnections. One reason is that multiple interconnection requests may be submitted representing alternative sites for one proposed facility. For this and other reasons, it is possible that much of this capacity will not be built.

STP Attachment 14

PrarieGold Venture Partners

- home
- team
- investment focus
- portfolio companies
- contact us

General Compression Signs Agreement with ConocoPhillips to Develop CAES Projects

posted - APR 14, 2010

NEWTON, Mass., April 14 /PRNewswire/ -- General Compression, Inc. ("GC"), a Massachusetts company developing an innovative compressed air energy storage system, today announced it has signed an agreement with ConocoPhillips (NYSE: COP) of Houston, Texas, to develop compressed air energy storage projects, beginning with a pilot project in Texas, using General Compression's Advanced Energy Storage ("GC*AES*™") technology.

"General Compression is extremely pleased to have ConocoPhillips as a development partner. ConocoPhillips is a global leader in energy and has a clear commitment to bringing new technology and innovation to projects. We are excited to build transformative energy projects that will increase the dependability of renewables for wholesale electricity customers," said Eric Ingersoll, CEO of General Compression.

GC and ConocoPhillips are evaluating a multiple-phase pilot project in Texas that would incorporate GC*AES*™ technology with wind energy, underground air storage and power sales.

"Storage has become a major issue and opportunity in the global power markets. We are excited about the prospect of developing an efficient and cost-effective solution that addresses the issues of intermittency and the growth of renewable power on the grid," said David Marcus, President of General Compression.

GC*AES*™ is a modular compressor/expander unit that has a nominal size of 2 MW and features a roundtrip electrical efficiency in excess of 70 percent. Unlike conventional turbomachinery-based compressed air energy storage, GC*AES*™ consumes no fuel and emits no carbon. GC*AES*™ technology can increase utility reliance on renewables, eliminate wind power curtailment, enhance transmission utilization, and make dispatchable renewable power available to customers.

About General Compression

Founded in 2006, General Compression, Inc. has made patent-pending advancements in the fields of isothermal compression and expansion to provide utility-scale storage for clean electricity sources such as wind and solar. GC's near-isothermal compressor/expander module is used to create 2 MW to 1,000 MW, 8 to 300 hour discharge, compressed air energy storage (CAES) projects. Company founders Eric Ingersoll, David Marcus, and Michael Marcus launched GC with a vision of creating Dispatchable Wind™ to integrate low-cost bulk storage with wind farms to eliminate the issues of intermittent power generation. The company's technology and projects are designed to set clean, domestic wind power on a path to become the dominant electric power generation source in the United States. General Compression raised over $17 million in Series A financing in 2010. GC can be found on the web at www.generalcompression.com.

For additional information, please contact David Marcus, President, at 617-559-9999.

SOURCE General Compression, Inc.

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STP Attachment 15

REPORT ON THE CAPACITY, DEMAND, AND RESERVES IN THE ERCOT REGION

May 2010

ERCOT
2705 West Lake Drive
Taylor, Texas 76574

Contents

Disclaimer

CDR WORKING PAPER

FOR PLANNING PURPOSES ONLY

This ERCOT Working Paper has been prepared for specific ERCOT and market participant purposes and has been developed from data provided by ERCOT market participants. The data may contain errors or become obsolete and thereby affect the conclusions and opinions of the Working Paper. ERCOT MAKES NO WARRANTY, EXPRESS OR IMPLIED, INCLUDING ANY WARRANTY OF MERCHANTABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE, AND DISCLAIMS ANY AND ALL LIABILITY WITH RESPECT TO THE ACCURACY OF SAME OR THE FITNESS OR APPROPRIATENESS OF SAME FOR ANY PARTICULAR USE. THIS ERCOT WORKING PAPER IS SUPPLIED WITH ALL FAULTS. The specific suitability for any use of the Working Paper and its accuracy should be confirmed by each ERCOT market participant that contributed data for this Working Paper.

This Working Paper is based on data submitted by ERCOT market participants as part of their Annual Load Data Request (ALDR) and their generation asset registration and on data in the EIA-411. As such, this data is updated on an ongoing basis, which means that this report can be rendered obsolete without notice.

Definitions

Available Mothballed Generation

The probability that a mothballed unit will return to service, as provided by its owner, multiplied by the capacity of the unit. Return probabilities are considered protected information under the ERCOT Protocols and therefore are not included in this report.

BULs

Balancing up load. Loads capable of reducing the need for electrical energy when providing Balancing Up Load Energy Service as described in the ERCOT Protocols, Section 6, Ancillary Services. BULs are not considered resources as defined by the ERCOT Protocols.

Effective Load-Carrying Capability (ELCC) of Wind Generation

The amount of wind generation that the Generation Adequacy Task Force (GATF) has recommended to be included in the CDR. The value is 8.7% of the nameplate capacity listed in the Unit Capacities tables, both installed capacity and planned capacity.

Emergency Interruptible Load Service

ERCOT procures Emergency Interruptible Load Service (EILS) by selecting qualified Loads to make themselves available for interruption in an electric grid emergency. EILS is an emergency load reduction service designed to decrease the likelihood of the need for firm Load shedding (a.k.a, "rolling blackouts"). Customers meeting EILS criteria may bid to provide the service through their qualified scheduling entities (QSEs). EILS is authorized by Public Utility Commission Substantive Rule §25.507.

LaaRs (Loads acting as resources)

Load capable of reducing or increasing the need for electrical energy or providing Ancillary Services to the ERCOT System, as described in the ERCOT Protocols, Section 6, Ancillary Services. These Resources may provide the following Ancillary Services: Responsive Reserve Service, Non-Spinning Reserve Service, Replacement Reserve Service, and Regulation Service. The Resources must be registered and qualified by ERCOT and will be scheduled by a Qualified Scheduling Entity

Mothballed Capacity

The difference in the available mothballed generation (see definition above) and the total mothballed capacity. This value is zero in the upcoming Summer CDR Report because there isn't enough time to return those units to service before the start of the summer.

Mothballed Unit

A generation resource for which a generation entity has submitted a Notification of Suspension of Operations, for which ERCOT has declined to execute an RMR agreement, and for which the generation entity has not announced retirement of the generation resource.

Net Dependable Capability

Maximum sustainable capability of a generation resource as demonstrated by performance testing.

Non-Synchronous Tie
Any non-synchronous transmission interconnection between ERCOT and non-ERCOT electric power systems

Other Potential Resources
Capacity resources that include one of the following:
- Remaining "mothballed" capacity not included as resources in the reserve margin
- Remaining DC tie capacity not included as resources in the reserve margin calculation,
- New generating units that have initiated full transmission interconnection studies through the ERCOT generation interconnection process (Note that new wind generating units would be included based on the appropriate discounted capacity value applied to existing wind generating units.)

Planned Units in Full Interconnection Study Phase
To connect new generation to the ERCOT grid, a generation developer must go through a set procedure. The first step is a high-level screening study to determine the effects of adding the new generation on the transmission system. The second step is the full interconnection study. These are detailed studies done by the transmission owners to determine the effects of the addition of new generation on the transmission system.

Private Networks
An electric network connected to the ERCOT transmission grid that contains load that is not directly metered by ERCOT (i.e., load that is typically netted with internal generation).

Reliability Must-Run (RMR) Unit
A generation resource unit operated under the terms of an agreement with ERCOT that would not otherwise be operated except that they are necessary to provide voltage support, stability or management of localized transmission constraints under first contingency criteria.

Signed IA (Interconnection Agreement)
An agreement that sets forth requirements for physical connection between an eligible transmission service customer and a transmission or distribution service provider

Switchable Unit
A generation resource that can be connected to either the ERCOT transmission grid or a grid outside the ERCOT Region.

STP Attachment 16

Report on the Capacity, Demand and Reserves in the ERCOT Region

December 2009

Contents

Disclaimer

CDR WORKING PAPER

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This Working Paper is based on data submitted by ERCOT market participants as part of their Annual Load Data Request (ALDR) and their resource asset registration. As such, this data is updated on an ongoing basis, which means that this report can be rendered obsolete without notice.

2009 Report on the Capacity, Demand, and Reserves in the ERCOT Region

Summer Summary (December Update)

Load Forecast:	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Total Summer Peak Demand, MW	64,056	65,494	67,394	69,399	70,837	72,172
less LaaRs Serving as Responsive Reserve, MW	1,115	1,115	1,115	1,115	1,115	1,115
less LaaRs Serving as Non-Spinning Reserve, MW	0	0	0	0	0	0
less BULs, MW	0	0	0	0	0	0
less Energy Efficiency Programs (per HB3693)	242	242	242	242	242	242
Firm Load Forecast, MW	**62,699**	**64,137**	**66,037**	**68,042**	**69,480**	**70,815**

Resources:	**2010**	**2011**	**2012**	**2013**	**2014**	**2014**
Installed Capacity, MW	64,940	64,940	64,940	64,940	64,940	64,940
Capacity from Private Use Networks, MW	5,318	5,343	5,343	5,343	5,343	5,343
Effective Load-Carrying Capability (ELCC) of Wind Generation, MW	776	776	776	776	776	776
RMR Units to be under Contract, MW	627	0	0	0	0	0
Operational Generation, MW	**71,660**	**71,058**	**71,058**	**71,058**	**71,058**	**71,058**
50% of DC-Ties, MW	553	553	553	553	553	553
Switchable Resources, MW	2,848	2,848	2,848	2,848	2,848	2,848
Available Mothballed Generation , MW	104	157	157	157	157	157
Planned Units (not wind) with Signed IA and Air Permit, MW*	1,329	2,212	3,237	3,237	3,237	3,237
ELCC of Planned Wind Units with Signed IA, MW	26	69	142	164	164	164
Total Resources, MW	**76,521**	**76,897**	**77,995**	**78,017**	**78,017**	**78,017**
less Switchable Resources Unavailable to ERCOT, MW	158	0	0	0	0	0
less Retiring Units, MW	0	0	0	0	0	0
Resources, MW	**76,363**	**76,897**	**77,995**	**78,017**	**78,017**	**78,017**
Reserve Margin	**21.8%**	**19.9%**	**18.1%**	**14.7%**	**12.3%**	**10.2%**
(Resources - Firm Load Forecast)/Firm Load Forecast						

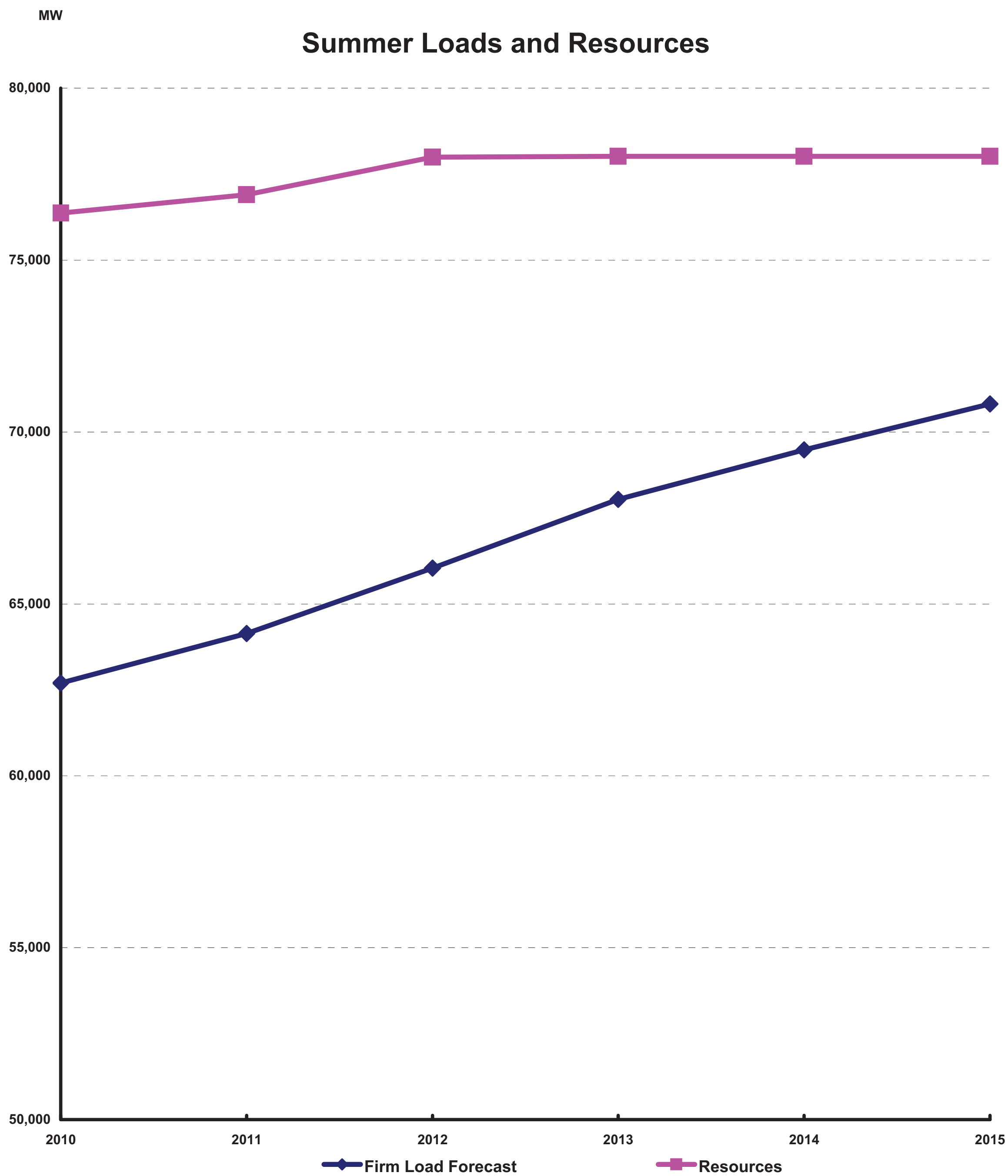
Other Potential Resources:	**6,357**	**12,258**	**19,457**	**21,051**	**23,992**	**24,035**
Remaining Mothballed Capacity , MW	3,053	3,001	3,001	3,001	3,001	3,001
50% of DC-Ties, MW	553	553	553	553	553	553
Planned Units in Full Interconnection Study Phase, MW	2,751	8,704	15,903	17,497	20,438	20,482

*

According to the Board-approved CDR methodology, a planned generator is included in the reserves calculation if it has obtained a signed interconnection agreement and air permit. However, one generator which meets these criteria has provided a formal letter from a corporate officer to ERCOT stating that, based on its current expectations, its planned 1,792 MW unit that had requested interconnection beginning in 2013 should not be included in the reserves calculation. Therefore, that unit has been excluded.

2009 Report on the Capacity, Demand, and Reserves in the ERCOT Region

Summer Summary (December Update)



Unit Capacities - Summer

Units used in determining the generation resources in the Summer Summary

Operational capacities are based on unit testing. Other capacities are based on information provided by the plant owners. This list includes MW available to the grid from private network (self-serve) units. It also includes distributed generation units that have registered with ERCOT. Data without unit names are for private network units or are planned generation that is not public.

Unit Name	Unit Code	County	Fuel	CM Zone	2010	2011	2012	2013	2014	2015
A von Rosenberg 1-CT1	BRAUNIG_AVR1_CT1	Bexar	Gas	South	145.0	145.0	145.0	145.0	145.0	145.0
A von Rosenberg 1-CT2	BRAUNIG_AVR1_CT2	Bexar	Gas	South	145.0	145.0	145.0	145.0	145.0	145.0
A von Rosenberg 1-ST1	BRAUNIG_AVR1_ST	Bexar	Gas	South	160.0	160.0	160.0	160.0	160.0	160.0
AEDOMG 1	DG_SUMMI_1UNIT	Travis	Gas	South	5.0	5.0	5.0	5.0	5.0	5.0
AES Deepwater	APD_APD_G1	Harris	Other	South	138.0	138.0	138.0	138.0	138.0	138.0
Amistad Hydro 1	AMISTAD_AMISTAG1	Val Verde	Hydro	South	38.0	38.0	38.0	38.0	38.0	38.0
Amistad Hydro 2	AMISTAD_AMISTAG2	Val Verde	Hydro	South	38.0	38.0	38.0	38.0	38.0	38.0
Atascocita 1	_HB_DG1	Harris	Biomass	Houston	10.1	10.1	10.1	10.1	10.1	10.1
Atkins 7	ATKINS_ATKINSG7	Brazos	Gas	North	20.0	20.0	20.0	20.0	20.0	20.0
Austin 1	AUSTPL_AUSTING1	Travis	Hydro	South	8.0	8.0	8.0	8.0	8.0	8.0
Austin 2	AUSTPL_AUSTING2	Travis	Hydro	South	9.0	9.0	9.0	9.0	9.0	9.0
Austin Landfill Gas	DG_SPRIN_4UNITS	Travis	Other	South	6.4	6.4	6.4	6.4	6.4	6.4
B M Davis 1	B_DAVIS_B_DAVIG1	Nueces	Gas	South	335.0	335.0	335.0	335.0	335.0	335.0
B M Davis 2	B_DAVIS_B_DAVIG2	Nueces	Gas	South	344.0	344.0	344.0	344.0	344.0	344.0
B M Davis 3	B_DAVIS_B_DAVIG3	Nueces	Gas	South	190.0	190.0	190.0	190.0	190.0	190.0
B M Davis 4	B_DAVIS_B_DAVIG4	Nueces	Gas	South	190.0	190.0	190.0	190.0	190.0	190.0
Bastrop Energy Center 1	BASTEN_GTG1100	Bastrop	Gas	South	152.0	152.0	152.0	152.0	152.0	152.0
Bastrop Energy Center 2	BASTEN_GTG2100	Bastrop	Gas	South	150.0	150.0	150.0	150.0	150.0	150.0
Bastrop Energy Center 3	BASTEN_ST0100	Bastrop	Gas	South	233.0	233.0	233.0	233.0	233.0	233.0
Baytown 1	TRN_DG1	Chambers	Biomass	Houston	3.9	3.9	3.9	3.9	3.9	3.9
Big Brown 1	BBSES_UNIT1	Freestone	Coal	North	617.0	617.0	617.0	617.0	617.0	617.0
Big Brown 2	BBSES_UNIT2	Freestone	Coal	North	615.0	615.0	615.0	615.0	615.0	615.0
Bio Energy Partners	DG_BIOE_2UNITS	Denton	Gas	North	5.6	5.6	5.6	5.6	5.6	5.6
Bluebonnet 1	_LB_DG1	Harris	Biomass	Houston	3.9	3.9	3.9	3.9	3.9	3.9
Bosque County Peaking 1	BOSQUESW_BSQSU_1	Bosque	Gas	North	153.0	153.0	153.0	153.0	153.0	153.0
Bosque County Peaking 2	BOSQUESW_BSQSU_2	Bosque	Gas	North	153.0	153.0	153.0	153.0	153.0	153.0
Bosque County Peaking 3	BOSQUESW_BSQSU_3	Bosque	Gas	North	154.0	154.0	154.0	154.0	154.0	154.0
Bosque County Peaking 4	BOSQUESW_BSQSU_4	Bosque	Gas	North	83.0	83.0	83.0	83.0	83.0	83.0
Bosque County Unit 5	BOSQUESW_BSQSU_5	Bosque	Gas	North	240.0	240.0	240.0	240.0	240.0	240.0
Brazos Valley 1	BVE_Unit1	Ft Bend	Gas	Houston	163.0	163.0	163.0	163.0	163.0	163.0
Brazos Valley 2	BVE_Unit2	Ft Bend	Gas	Houston	163.0	163.0	163.0	163.0	163.0	163.0
Brazos Valley 3	BVE_Unit3	Ft Bend	Gas	Houston	253.0	253.0	253.0	253.0	253.0	253.0
Buchanan 1	BUCHAN_BUCHANG1	Llano	Hydro	South	18.0	18.0	18.0	18.0	18.0	18.0
Buchanan 2	BUCHAN_BUCHANG2	Llano	Hydro	South	18.0	18.0	18.0	18.0	18.0	18.0
Buchanan 3	BUCHAN_BUCHANG3	Llano	Hydro	South	18.0	18.0	18.0	18.0	18.0	18.0
Calenergy (Falcon Seaboard) 1	FLCNS_UNIT1	Howard	Gas	West	75.0	75.0	75.0	75.0	75.0	75.0
Calenergy (Falcon Seaboard) 2	FLCNS_UNIT2	Howard	Gas	West	75.0	75.0	75.0	75.0	75.0	75.0
Calenergy (Falcon Seaboard) 3	FLCNS_UNIT3	Howard	Gas	West	70.0	70.0	70.0	70.0	70.0	70.0
Canyon 1	CANYHY_CANYHYG1	Comal	Hydro	South	3.0	3.0	3.0	3.0	3.0	3.0
Canyon 2	CANYHY_CANYHYG2	Comal	Hydro	South	3.0	3.0	3.0	3.0	3.0	3.0
Cedar Bayou 1	CBY_CBY_G1	Chambers	Gas	Houston	745.0	745.0	745.0	745.0	745.0	745.0
Cedar Bayou 2	CBY_CBY_G2	Chambers	Gas	Houston	749.0	749.0	749.0	749.0	749.0	749.0
Cedar Bayou 4	CBY4_CT41	Chambers	Gas	Houston	169.0	169.0	169.0	169.0	169.0	169.0
Cedar Bayou 5	CBY4_CT42	Chambers	Gas	Houston	169.0	169.0	169.0	169.0	169.0	169.0
Cedar Bayou 6	CBY4_ST04	Chambers	Gas	Houston	180.0	180.0	180.0	180.0	180.0	180.0
Channel Energy Deepwater	CHEDPW_GT2	Harris	Gas	Houston	182.0	182.0	182.0	182.0	182.0	182.0
Coastal Plains RDF	_AV_DG1	Galveston	Biomass	South	6.7	6.7	6.7	6.7	6.7	6.7
Coleto Creek	COLETO_COLETOG1	Goliad	Coal	South	632.0	632.0	632.0	632.0	632.0	632.0
Colorado Bend Energy Center	CBEC_GT1	Wharton	Gas	Houston	77.0	77.0	77.0	77.0	77.0	77.0
Colorado Bend Energy Center	CBEC_GT2	Wharton	Gas	Houston	77.0	77.0	77.0	77.0	77.0	77.0
Colorado Bend Energy Center	CBEC_GT3	Wharton	Gas	Houston	77.0	77.0	77.0	77.0	77.0	77.0
Colorado Bend Energy Center	CBEC_GT4	Wharton	Gas	Houston	77.0	77.0	77.0	77.0	77.0	77.0
Colorado Bend Energy Center	CBEC_STG1	Wharton	Gas	Houston	105.0	105.0	105.0	105.0	105.0	105.0
Colorado Bend Energy Center	CBEC_STG2	Wharton	Gas	Houston	105.0	105.0	105.0	105.0	105.0	105.0
Comanche Peak 1	CPSES_UNIT1	Somervell	Nuclear	North	1209.0	1209.0	1209.0	1209.0	1209.0	1209.0
Comanche Peak 2	CPSES_UNIT2	Somervell	Nuclear	North	1158.0	1158.0	1158.0	1158.0	1158.0	1158.0
Corrugated Medium Mill	DG_FORSW_1UNIT	Kaufman	Gas	North	4.8	4.8	4.8	4.8	4.8	4.8
Covel Gardens LG Power Station	DG_MEDIN_1UNIT	Bexar	Other	South	10.0	10.0	10.0	10.0	10.0	10.0
CVC Channelview 1	CVC_CVC_G1	Harris	Gas	Houston	156.0	156.0	156.0	156.0	156.0	156.0
CVC Channelview 2	CVC_CVC_G2	Harris	Gas	Houston	158.0	158.0	158.0	158.0	158.0	158.0
CVC Channelview 3	CVC_CVC_G3	Harris	Gas	Houston	160.0	160.0	160.0	160.0	160.0	160.0
CVC Channelview 5	CVC_CVC_G5	Harris	Gas	Houston	122.0	122.0	122.0	122.0	122.0	122.0
Dansby 1	DANSBY_DANSBYG1	Brazos	Gas	North	110.0	110.0	110.0	110.0	110.0	110.0
Dansby 2	DANSBY_DANSBYG2	Brazos	Gas	North	48.0	48.0	48.0	48.0	48.0	48.0
Dansby 3	DANSBY_DANSBYG3	Brazos	Gas	North	48.0	48.0	48.0	48.0	48.0	48.0
Decker Creek 1	DECKER_DPG1	Travis	Gas	South	315.0	315.0	315.0	315.0	315.0	315.0
Decker Creek 2	DECKER_DPG2	Travis	Gas	South	420.0	420.0	420.0	420.0	420.0	420.0
Decker Creek G1	DECKER_DPGT_1	Travis	Gas	South	48.0	48.0	48.0	48.0	48.0	48.0
Decker Creek G2	DECKER_DPGT_2	Travis	Gas	South	48.0	48.0	48.0	48.0	48.0	48.0
Decker Creek G3	DECKER_DPGT_3	Travis	Gas	South	48.0	48.0	48.0	48.0	48.0	48.0
Decker Creek G4	DECKER_DPGT_4	Travis	Gas	South	48.0	48.0	48.0	48.0	48.0	48.0

Unit Capacities - Summer

Units used in determining the generation resources in the Summer Summary

Operational capacities are based on unit testing. Other capacities are based on information provided by the plant owners. This list includes MW available to the grid from private network (self-serve) units. It also includes distributed generation units that have registered with ERCOT. Data without unit names are for private network units or are planned generation that is not public.

Unit Name	Unit Code	County	Fuel	CM Zone	2010	2011	2012	2013	2014	2015
DeCordova A	DCSES_CT10	Hood	Gas	North	66.0	66.0	66.0	66.0	66.0	66.0
DeCordova B	DCSES_CT20	Hood	Gas	North	66.0	66.0	66.0	66.0	66.0	66.0
DeCordova C	DCSES_CT30	Hood	Gas	North	66.0	66.0	66.0	66.0	66.0	66.0
DeCordova D	DCSES_CT40	Hood	Gas	North	66.0	66.0	66.0	66.0	66.0	66.0
Deer Park Energy Center 1	DDPEC_GT1	Harris	Gas	Houston	163.0	163.0	163.0	163.0	163.0	163.0
Deer Park Energy Center 2	DDPEC_GT2	Harris	Gas	Houston	157.0	157.0	157.0	157.0	157.0	157.0
Deer Park Energy Center 3	DDPEC_GT3	Harris	Gas	Houston	158.0	158.0	158.0	158.0	158.0	158.0
Deer Park Energy Center 4	DDPEC_GT4	Harris	Gas	Houston	157.0	157.0	157.0	157.0	157.0	157.0
Deer Park Energy Center S	DDPEC_ST1	Harris	Gas	Houston	238.0	238.0	238.0	238.0	238.0	238.0
Denison Dam 1	DNDAM_DENISOG1	Grayson	Hydro	North	40.0	40.0	40.0	40.0	40.0	40.0
Denison Dam 2	DNDAM_DENISOG2	Grayson	Hydro	North	40.0	40.0	40.0	40.0	40.0	40.0
DFW Gas Recovery	DG_BIO2_4UNITS	Denton	Biomass	North	6.4	6.4	6.4	6.4	6.4	6.4
Dunlop (Schumansville) 1	DG_SCHUM_2UNITS	Guadalupe	Hydro	South	3.6	3.6	3.6	3.6	3.6	3.6
Eagle Pass 1	EAGLE_HY_EAGLE_HY1	Maverick	Hydro	South	2.0	2.0	2.0	2.0	2.0	2.0
Eagle Pass 2	EAGLE_HY_EAGLE_HY2	Maverick	Hydro	South	2.0	2.0	2.0	2.0	2.0	2.0
Eagle Pass 3	EAGLE_HY_EAGLE_HY3	Maverick	Hydro	South	2.0	2.0	2.0	2.0	2.0	2.0
Ennis Power Station 1	ETCCS_UNIT1	Ellis	Gas	North	116.0	116.0	116.0	116.0	116.0	116.0
Ennis Power Station 2	ETCCS_CT1	Ellis	Gas	North	196.0	196.0	196.0	196.0	196.0	196.0
ExTex La Porte Power Station (AirPro) 1	_AZ__AZ_G1	Harris	Gas	Houston	38.0	38.0	38.0	38.0	38.0	38.0
ExTex La Porte Power Station (AirPro) 2	_AZ__AZ_G2	Harris	Gas	Houston	38.0	38.0	38.0	38.0	38.0	38.0
ExTex La Porte Power Station (AirPro) 3	_AZ__AZ_G3	Harris	Gas	Houston	38.0	38.0	38.0	38.0	38.0	38.0
ExTex La Porte Power Station (AirPro) 4	_AZ__AZ_G4	Harris	Gas	Houston	38.0	38.0	38.0	38.0	38.0	38.0
Falcon Hydro 1	FALCON_FALCONG1	Starr	Hydro	South	12.0	12.0	12.0	12.0	12.0	12.0
Falcon Hydro 2	FALCON_FALCONG2	Starr	Hydro	South	12.0	12.0	12.0	12.0	12.0	12.0
Falcon Hydro 3	FALCON_FALCONG3	Starr	Hydro	South	12.0	12.0	12.0	12.0	12.0	12.0
Fayette Power Project 1	FPPYD1_FPP_G1	Fayette	Coal	South	608.0	608.0	608.0	608.0	608.0	608.0
Fayette Power Project 2	FPPYD1_FPP_G2	Fayette	Coal	South	608.0	608.0	608.0	608.0	608.0	608.0
Fayette Power Project 3	FPPYD2_FPP_G3	Fayette	Coal	South	445.0	445.0	445.0	445.0	445.0	445.0
Forney Energy Center GT11	FRNYPP_GT11	Kaufman	Gas	North	165.0	165.0	165.0	165.0	165.0	165.0
Forney Energy Center GT12	FRNYPP_GT12	Kaufman	Gas	North	165.0	165.0	165.0	165.0	165.0	165.0
Forney Energy Center GT13	FRNYPP_GT13	Kaufman	Gas	North	165.0	165.0	165.0	165.0	165.0	165.0
Forney Energy Center GT21	FRNYPP_GT21	Kaufman	Gas	North	165.0	165.0	165.0	165.0	165.0	165.0
Forney Energy Center GT22	FRNYPP_GT22	Kaufman	Gas	North	165.0	165.0	165.0	165.0	165.0	165.0
Forney Energy Center GT23	FRNYPP_GT23	Kaufman	Gas	North	165.0	165.0	165.0	165.0	165.0	165.0
Forney Energy Center STG10	FRNYPP_ST10	Kaufman	Gas	North	415.0	415.0	415.0	415.0	415.0	415.0
Forney Energy Center STG20	FRNYPP_ST20	Kaufman	Gas	North	415.0	415.0	415.0	415.0	415.0	415.0
Freestone Energy Center 1	FREC_GT1	Freestone	Gas	North	152.0	152.0	152.0	152.0	152.0	152.0
Freestone Energy Center 2	FREC_GT2	Freestone	Gas	North	152.0	152.0	152.0	152.0	152.0	152.0
Freestone Energy Center 3	FREC_ST3	Freestone	Gas	North	175.0	175.0	175.0	175.0	175.0	175.0
Freestone Energy Center 4	FREC_GT4	Freestone	Gas	North	152.0	152.0	152.0	152.0	152.0	152.0
Freestone Energy Center 5	FREC_GT5	Freestone	Gas	North	152.0	152.0	152.0	152.0	152.0	152.0
Freestone Energy Center 6	FREC_ST6	Freestone	Gas	North	175.0	175.0	175.0	175.0	175.0	175.0
Frontera 1	FRONTERA_FRONTEG1	Hidalgo	Gas	South	146.0	146.0	146.0	146.0	146.0	146.0
Frontera 2	FRONTERA_FRONTEG2	Hidalgo	Gas	South	148.0	148.0	148.0	148.0	148.0	148.0
Frontera 3	FRONTERA_FRONTEG3	Hidalgo	Gas	South	173.0	173.0	173.0	173.0	173.0	173.0
FW Regional LFG Generation Facility 1	DG_RDLML_1UNIT	Tarrant	Other	North	1.5	1.5	1.5	1.5	1.5	1.5
GBRA 4 & 5	DG_LKWDT_2UNITS	Gonzales	Other	South	4.8	4.8	4.8	4.8	4.8	4.8
Gibbons Creek 1	GIBCRK_GIB_CRG1	Grimes	Coal	North	470.0	470.0	470.0	470.0	470.0	470.0
Graham 1	GRSES_UNIT1	Young	Gas	North	230.0	230.0	230.0	230.0	230.0	230.0
Graham 2	GRSES_UNIT2	Young	Gas	North	390.0	390.0	390.0	390.0	390.0	390.0
Granite Shoals 1	WIRTZ_WIRTZ_G1	Burnet	Hydro	South	30.0	30.0	30.0	30.0	30.0	30.0
Granite Shoals 2	WIRTZ_WIRTZ_G2	Burnet	Hydro	South	30.0	30.0	30.0	30.0	30.0	30.0
Greens Bayou 5	GBY_GBY_5	Harris	Gas	Houston	406.0	406.0	406.0	406.0	406.0	406.0
Greens Bayou 73	GBY_GBYGT73	Harris	Gas	Houston	46.0	46.0	46.0	46.0	46.0	46.0
Greens Bayou 74	GBY_GBYGT74	Harris	Gas	Houston	46.0	46.0	46.0	46.0	46.0	46.0
Greens Bayou 81	GBY_GBYGT81	Harris	Gas	Houston	46.0	46.0	46.0	46.0	46.0	46.0
Greens Bayou 82	GBY_GBYGT82	Harris	Gas	Houston	56.0	56.0	56.0	56.0	56.0	56.0
Greens Bayou 83	GBY_GBYGT83	Harris	Gas	Houston	56.0	56.0	56.0	56.0	56.0	56.0
Greens Bayou 84	GBY_GBYGT84	Harris	Gas	Houston	56.0	56.0	56.0	56.0	56.0	56.0
Guadalupe Generating Station 1	GUADG_GAS1	Guadalupe	Gas	South	151.0	151.0	151.0	151.0	151.0	151.0
Guadalupe Generating Station 2	GUADG_GAS2	Guadalupe	Gas	South	151.0	151.0	151.0	151.0	151.0	151.0
Guadalupe Generating Station 3	GUADG_GAS3	Guadalupe	Gas	South	149.0	149.0	149.0	149.0	149.0	149.0
Guadalupe Generating Station 4	GUADG_GAS4	Guadalupe	Gas	South	152.0	152.0	152.0	152.0	152.0	152.0
Guadalupe Generating Station 5	GUADG_STM5	Guadalupe	Gas	South	170.0	170.0	170.0	170.0	170.0	170.0
Guadalupe Generating Station 6	GUADG_STM6	Guadalupe	Gas	South	169.0	169.0	169.0	169.0	169.0	169.0
Handley 3	HLSES_UNIT3	Tarrant	Gas	North	395.0	395.0	395.0	395.0	395.0	395.0
Handley 4	HLSES_UNIT4	Tarrant	Gas	North	435.0	435.0	435.0	435.0	435.0	435.0
Handley 5	HLSES_UNIT5	Tarrant	Gas	North	435.0	435.0	435.0	435.0	435.0	435.0
Hays Energy Facility 1	HAYSEN_HAYSENG1	Hays	Gas	South	216.0	216.0	216.0	216.0	216.0	216.0
Hays Energy Facility 2	HAYSEN_HAYSENG2	Hays	Gas	South	216.0	216.0	216.0	216.0	216.0	216.0
Hays Energy Facility 3	HAYSEN_HAYSENG3	Hays	Gas	South	225.0	225.0	225.0	225.0	225.0	225.0

Unit Capacities - Summer

Units used in determining the generation resources in the Summer Summary

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Unit Name	Unit Code	County	Fuel	CM Zone	2010	2011	2012	2013	2014	2015
Hays Energy Facility 4	HAYSEN_HAYSENG4	Hays	Gas	South	225.0	225.0	225.0	225.0	225.0	225.0
Hidalgo 1	DUKE_DUKE_GT1	Hidalgo	Gas	South	141.0	141.0	141.0	141.0	141.0	141.0
Hidalgo 2	DUKE_DUKE_GT2	Hidalgo	Gas	South	141.0	141.0	141.0	141.0	141.0	141.0
Hidalgo 3	DUKE_DUKE_ST1	Hidalgo	Gas	South	168.0	168.0	168.0	168.0	168.0	168.0
Inks 1	INKSDA_INKS_G1	Llano	Hydro	South	14.0	14.0	14.0	14.0	14.0	14.0
J K Spruce 1	CALAVERS_JKS1	Bexar	Coal	South	555.0	555.0	555.0	555.0	555.0	555.0
J K Spruce 2	CALAVERS_JKS2	Bexar	Coal	South	772.0	772.0	772.0	772.0	772.0	772.0
J T Deely 1	CALAVERS_JTD1	Bexar	Coal	South	440.0	440.0	440.0	440.0	440.0	440.0
J T Deely 2	CALAVERS_JTD2	Bexar	Coal	South	440.0	440.0	440.0	440.0	440.0	440.0
Jack County Generation Facility 1	JACKCNTY_CT1	Jack	Gas	North	142.0	142.0	142.0	142.0	142.0	142.0
Jack County Generation Facility 2	JACKCNTY_CT2	Jack	Gas	North	142.0	142.0	142.0	142.0	142.0	142.0
Jack County Generation Facility 3	JACKCNTY_STG	Jack	Gas	North	281.0	281.0	281.0	281.0	281.0	281.0
Johnson County Generation Facility 1	TEN_CT1	Johnson	Gas	North	150.0	150.0	150.0	150.0	150.0	150.0
Johnson County Generation Facility 2	TEN_STG	Johnson	Gas	North	106.0	106.0	106.0	106.0	106.0	106.0
Lake Hubbard 1	LHSES_UNIT1	Dallas	Gas	North	392.0	392.0	392.0	392.0	392.0	392.0
Lake Hubbard 2	LH2SES_UNIT2	Dallas	Gas	North	524.0	524.0	524.0	524.0	524.0	524.0
Lamar Power Project CT11	LPCCS_CT11	Lamar	Gas	North	156.0	156.0	156.0	156.0	156.0	156.0
Lamar Power Project CT12	LPCCS_CT12	Lamar	Gas	North	157.0	157.0	157.0	157.0	157.0	157.0
Lamar Power Project CT21	LPCCS_CT21	Lamar	Gas	North	156.0	156.0	156.0	156.0	156.0	156.0
Lamar Power Project CT22	LPCCS_CT22	Lamar	Gas	North	157.0	157.0	157.0	157.0	157.0	157.0
Lamar Power Project STG1	LPCCS_UNIT1	Lamar	Gas	North	198.0	198.0	198.0	198.0	198.0	198.0
Lamar Power Project STG2	LPCCS_UNIT2	Lamar	Gas	North	198.0	198.0	198.0	198.0	198.0	198.0
Laredo Peaking 4	LARDVFTN_G4	Webb	Gas	South	94.0	94.0	94.0	94.0	94.0	94.0
Laredo Peaking 5	LARDVFTN_G5	Webb	Gas	South	94.0	94.0	94.0	94.0	94.0	94.0
Leon Creek 3	LEON_CRK_LCP3G3	Bexar	Gas	South	56.0	56.0	56.0	56.0	56.0	56.0
Leon Creek 4	LEON_CRK_LCP4G4	Bexar	Gas	South	88.0	88.0	88.0	88.0	88.0	88.0
Leon Creek Peaking 1	LEON_CRK_LCPCT1	Bexar	Gas	South	45.0	45.0	45.0	45.0	45.0	45.0
Leon Creek Peaking 2	LEON_CRK_LCPCT2	Bexar	Gas	South	45.0	45.0	45.0	45.0	45.0	45.0
Leon Creek Peaking 3	LEON_CRK_LCPCT3	Bexar	Gas	South	45.0	45.0	45.0	45.0	45.0	45.0
Leon Creek Peaking 4	LEON_CRK_LCPCT4	Bexar	Gas	South	45.0	45.0	45.0	45.0	45.0	45.0
Lewisville 1	DG_LWSVL_1UNIT	Denton	Hydro	North	2.8	2.8	2.8	2.8	2.8	2.8
Limestone 1	LEG_LEG_G1	Limestone	Coal	North	831.0	831.0	831.0	831.0	831.0	831.0
Limestone 2	LEG_LEG_G2	Limestone	Coal	North	858.0	858.0	858.0	858.0	858.0	858.0
Lost Pines 1	LOSTPI_LOSTPGT1	Bastrop	Gas	South	167.0	167.0	167.0	167.0	167.0	167.0
Lost Pines 2	LOSTPI_LOSTPGT2	Bastrop	Gas	South	164.0	164.0	164.0	164.0	164.0	164.0
Lost Pines 3	LOSTPI_LOSTPST1	Bastrop	Gas	South	184.0	184.0	184.0	184.0	184.0	184.0
Magic Valley 1	NEDIN_NEDIN_G1	Hidalgo	Gas	South	166.0	166.0	166.0	166.0	166.0	166.0
Magic Valley 2	NEDIN_NEDIN_G2	Hidalgo	Gas	South	166.0	166.0	166.0	166.0	166.0	166.0
Magic Valley 3	NEDIN_NEDIN_G3	Hidalgo	Gas	South	204.0	204.0	204.0	204.0	204.0	204.0
Marble Falls 1	MARBFA_MARBFAG1	Burnet	Hydro	South	21.0	21.0	21.0	21.0	21.0	21.0
Marble Falls 2	MARBFA_MARBFAG2	Burnet	Hydro	South	21.0	21.0	21.0	21.0	21.0	21.0
Marshall Ford 1	MARSFO_MARSFOG1	Travis	Hydro	South	36.0	36.0	36.0	36.0	36.0	36.0
Marshall Ford 2	MARSFO_MARSFOG2	Travis	Hydro	South	35.0	35.0	35.0	35.0	35.0	35.0
Marshall Ford 3	MARSFO_MARSFOG3	Travis	Hydro	South	36.0	36.0	36.0	36.0	36.0	36.0
Martin Lake 1	MLSES_UNIT1	Rusk	Coal	North	800.0	800.0	800.0	800.0	800.0	800.0
Martin Lake 2	MLSES_UNIT2	Rusk	Coal	North	800.0	800.0	800.0	800.0	800.0	800.0
Martin Lake 3	MLSES_UNIT3	Rusk	Coal	North	818.0	818.0	818.0	818.0	818.0	818.0
McQueeney (Abbott)	DG_MCQUE_5UNITS	Guadalupe	Hydro	South	8.0	8.0	8.0	8.0	8.0	8.0
Midlothian 1	MDANP_CT1	Ellis	Gas	North	216.0	216.0	216.0	216.0	216.0	216.0
Midlothian 2	MDANP_CT2	Ellis	Gas	North	216.0	216.0	216.0	216.0	216.0	216.0
Midlothian 3	MDANP_CT3	Ellis	Gas	North	216.0	216.0	216.0	216.0	216.0	216.0
Midlothian 4	MDANP_CT4	Ellis	Gas	North	216.0	216.0	216.0	216.0	216.0	216.0
Midlothian 5	MDANP_CT5	Ellis	Gas	North	225.0	225.0	225.0	225.0	225.0	225.0
Midlothian 6	MDANP_CT6	Ellis	Gas	North	225.0	225.0	225.0	225.0	225.0	225.0
Monticello 1	MNSES_UNIT1	Titus	Coal	North	583.0	583.0	583.0	583.0	583.0	583.0
Monticello 2	MNSES_UNIT2	Titus	Coal	North	583.0	583.0	583.0	583.0	583.0	583.0
Monticello 3	MNSES_UNIT3	Titus	Coal	North	765.0	765.0	765.0	765.0	765.0	765.0
Morgan Creek A	MGSES_CT1	Mitchell	Gas	West	68.0	68.0	68.0	68.0	68.0	68.0
Morgan Creek B	MGSES_CT2	Mitchell	Gas	West	68.0	68.0	68.0	68.0	68.0	68.0
Morgan Creek C	MGSES_CT3	Mitchell	Gas	West	68.0	68.0	68.0	68.0	68.0	68.0
Morgan Creek D	MGSES_CT4	Mitchell	Gas	West	68.0	68.0	68.0	68.0	68.0	68.0
Morgan Creek E	MGSES_CT5	Mitchell	Gas	W10	68.0	68.0	68.0	68.0	68.0	68.0
Morgan Creek F	MGSES_CT6	Mitchell	Gas	West	68.0	68.0	68.0	68.0	68.0	68.0
Morris Sheppard	MSP_MSP_1	Palo Pinto	Hydro	North	12.0	12.0	12.0	12.0	12.0	12.0
Morris Sheppard	MSP_MSP_2	Palo Pinto	Hydro	North	12.0	12.0	12.0	12.0	12.0	12.0
Mountain Creek 6	MCSES_UNIT6	Dallas	Gas	North	120.0	120.0	120.0	120.0	120.0	120.0
Mountain Creek 7	MCSES_UNIT7	Dallas	Gas	North	115.0	115.0	115.0	115.0	115.0	115.0
Mountain Creek 8	MCSES_UNIT8	Dallas	Gas	North	565.0	565.0	565.0	565.0	565.0	565.0
Nelson Gardens Landfill 1	DG_PEARS_2UNITS	Bexar	Other	South	3.6	3.6	3.6	3.6	3.6	3.6
North Texas 1	NTX_NTX_1	Parker	Gas	North	18.0	18.0	18.0	18.0	18.0	18.0
North Texas 2	NTX_NTX_2	Parker	Gas	North	18.0	18.0	18.0	18.0	18.0	18.0

Unit Capacities - Summer

Units used in determining the generation resources in the Summer Summary

Operational capacities are based on unit testing. Other capacities are based on information provided by the plant owners. This list includes MW available to the grid from private network (self-serve) units. It also includes distributed generation units that have registered with ERCOT. Data without unit names are for private network units or are planned generation that is not public.

Unit Name	Unit Code	County	Fuel	CM Zone	2010	2011	2012	2013	2014	2015
North Texas 3	NTX_NTX_3	Parker	Gas	North	39.0	39.0	39.0	39.0	39.0	39.0
Nueces Bay 7	NUECES_B_NUECESG7	Nueces	Gas	South	351.0	351.0	351.0	351.0	351.0	351.0
Nueces Bay 8	NUECES_B_NUECESG8	Nueces	Gas	South	175.0	175.0	175.0	175.0	175.0	175.0
Nueces Bay 9	NUECES_B_NUECESG9	Nueces	Gas	South	175.0	175.0	175.0	175.0	175.0	175.0
O W Sommers 1	CALAVERS_OWS1	Bexar	Gas	South	400.0	400.0	400.0	400.0	400.0	400.0
O W Sommers 2	CALAVERS_OWS2	Bexar	Gas	South	395.0	395.0	395.0	395.0	395.0	395.0
Oak Grove SES Unit 1	OGSES_UNIT1	Robertson	Coal	North	917.0	917.0	917.0	917.0	917.0	917.0
Oak Ridge North 1-3	DG__RA_3UNITS	Montgomery	Other	Houston	4.8	4.8	4.8	4.8	4.8	4.8
Odessa-Ector Generating Station C11	OECCS_CT11	Ector	Gas	West	146.0	146.0	146.0	146.0	146.0	146.0
Odessa-Ector Generating Station C12	OECCS_CT12	Ector	Gas	West	139.0	139.0	139.0	139.0	139.0	139.0
Odessa-Ector Generating Station C21	OECCS_CT21	Ector	Gas	West	135.0	135.0	135.0	135.0	135.0	135.0
Odessa-Ector Generating Station C22	OECCS_CT22	Ector	Gas	West	153.0	153.0	153.0	153.0	153.0	153.0
Odessa-Ector Generating Station ST1	OECCS_UNIT1	Ector	Gas	West	210.0	210.0	210.0	210.0	210.0	210.0
Odessa-Ector Generating Station ST2	OECCS_UNIT2	Ector	Gas	West	210.0	210.0	210.0	210.0	210.0	210.0
Oklaunion 1	OKLA_OKLA_G1	Wilbarger	Coal	West	650.0	650.0	650.0	650.0	650.0	650.0
Paris Energy Center 1	TNSKA_GT1	Lamar	Gas	North	77.0	77.0	77.0	77.0	77.0	77.0
Paris Energy Center 2	TNSKA_GT2	Lamar	Gas	North	80.0	80.0	80.0	80.0	80.0	80.0
Paris Energy Center 3	TNSKA_STG	Lamar	Gas	North	88.0	88.0	88.0	88.0	88.0	88.0
Pearsall 1	PEARSALL_PEARS_1	Frio	Gas	South	25.0	25.0	25.0	25.0	25.0	25.0
Pearsall 2	PEARSALL_PEARS_2	Frio	Gas	South	25.0	25.0	25.0	25.0	25.0	25.0
Pearsall 3	PEARSALL_PEARS_3	Frio	Gas	South	25.0	25.0	25.0	25.0	25.0	25.0
Pearsall Engine Plant	PEARSAL2_ENG1	Frio	Gas	South	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG2	Frio	Gas	South	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG3	Frio	Gas	South	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG4	Frio	Gas	South	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG5	Frio	Gas	South	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG6	Frio	Gas	South	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG7	Frio	Gas	South	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG8	Frio	Gas	South	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG9	Frio	Gas	South	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG10	Frio	Gas	South	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG11	Frio	Gas	South	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG12	Frio	Gas	South	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG13	Frio	Gas	South	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG14	Frio	Gas	South	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG15	Frio	Gas	South	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG16	Frio	Gas	South	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG17	Frio	Gas	South	8.4	8.4	8.4	8.4	8.4	8.4
Pearsall Engine Plant	PEARSAL2_ENG18	Frio	Gas	South	8.4	8.4	8.4	8.4	8.4	8.4
Permian Basin A	PB2SES_CT1	Ward	Gas	West	68.0	68.0	68.0	68.0	68.0	68.0
Permian Basin B	PB2SES_CT2	Ward	Gas	West	65.0	65.0	65.0	65.0	65.0	65.0
Permian Basin C	PB2SES_CT3	Ward	Gas	West	68.0	68.0	68.0	68.0	68.0	68.0
Permian Basin D	PB2SES_CT4	Ward	Gas	West	69.0	69.0	69.0	69.0	69.0	69.0
Permian Basin E	PB2SES_CT5	Ward	Gas	West	70.0	70.0	70.0	70.0	70.0	70.0
Powerlane Plant 1	STEAM_STEAM_1	Hunt	Gas	North	20.0	20.0	20.0	20.0	20.0	20.0
Powerlane Plant 2	STEAM_STEAM_2	Hunt	Gas	North	1.0	1.0	1.0	1.0	1.0	1.0
Powerlane Plant 3	STEAM_STEAM_3	Hunt	Gas	North	41.0	41.0	41.0	41.0	41.0	41.0
Quail Run Energy GT1	QALSW_GT2	Ector	Gas	West	70.0	70.0	70.0	70.0	70.0	70.0
Quail Run Energy GT2	QALSW_GT3	Ector	Gas	West	70.0	70.0	70.0	70.0	70.0	70.0
Quail Run Energy GT3	QALSW_STG1	Ector	Gas	West	90.0	90.0	90.0	90.0	90.0	90.0
Quail Run Energy GT4	QALSW_STG2	Ector	Gas	West	90.0	90.0	90.0	90.0	90.0	90.0
Quail Run Energy STG1	QALSW_GT1	Ector	Gas	West	70.0	70.0	70.0	70.0	70.0	70.0
Quail Run Energy STG2	QALSW_GT4	Ector	Gas	West	70.0	70.0	70.0	70.0	70.0	70.0
R W Miller 1	MIL_MILLERG1	Palo Pinto	Gas	North	75.0	75.0	75.0	75.0	75.0	75.0
R W Miller 2	MIL_MILLERG2	Palo Pinto	Gas	North	120.0	120.0	120.0	120.0	120.0	120.0
R W Miller 3	MIL_MILLERG3	Palo Pinto	Gas	North	208.0	208.0	208.0	208.0	208.0	208.0
R W Miller 4	MIL_MILLERG4	Palo Pinto	Gas	North	104.0	104.0	104.0	104.0	104.0	104.0
R W Miller 5	MIL_MILLERG5	Palo Pinto	Gas	North	104.0	104.0	104.0	104.0	104.0	104.0
Ray Olinger 1	OLINGR_OLING_1	Collin	Gas	North	78.0	78.0	78.0	78.0	78.0	78.0
Ray Olinger 2	OLINGR_OLING_2	Collin	Gas	North	107.0	107.0	107.0	107.0	107.0	107.0
Ray Olinger 3	OLINGR_OLING_3	Collin	Gas	North	146.0	146.0	146.0	146.0	146.0	146.0
Ray Olinger 4	OLINGR_OLING_4	Collin	Gas	North	75.0	75.0	75.0	75.0	75.0	75.0
Rayburn 1	RAYBURN_RAYBURG1	Victoria	Gas	South	11.0	11.0	11.0	11.0	11.0	11.0
Rayburn 10	RAYBURN_RAYBURG10	Victoria	Gas	South	40.0	40.0	40.0	40.0	40.0	40.0
Rayburn 2	RAYBURN_RAYBURG2	Victoria	Gas	South	11.0	11.0	11.0	11.0	11.0	11.0
Rayburn 3	RAYBURN_RAYBURG3	Victoria	Gas	South	24.0	24.0	24.0	24.0	24.0	24.0
Rayburn 7	RAYBURN_RAYBURG7	Victoria	Gas	South	50.0	50.0	50.0	50.0	50.0	50.0
Rayburn 8	RAYBURN_RAYBURG8	Victoria	Gas	South	50.0	50.0	50.0	50.0	50.0	50.0
Rayburn 9	RAYBURN_RAYBURG9	Victoria	Gas	South	50.0	50.0	50.0	50.0	50.0	50.0
RGV Sugar Mill	DG_S_SNR_UNIT1	Hidalgo	Biomass	South	4.5	4.5	4.5	4.5	4.5	4.5
Rhodia Houston Plant	DG__HG_2UNITS	Harris	Other	Houston	7.5	7.5	7.5	7.5	7.5	7.5

Unit Capacities - Summer

Units used in determining the generation resources in the Summer Summary

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Unit Name	Unit Code	County	Fuel	CM Zone	2010	2011	2012	2013	2014	2015
Rio Nogales 1	RIONOG_CT1	Guadalupe	Gas	South	142.0	142.0	142.0	142.0	142.0	142.0
Rio Nogales 2	RIONOG_CT2	Guadalupe	Gas	South	142.0	142.0	142.0	142.0	142.0	142.0
Rio Nogales 3	RIONOG_CT3	Guadalupe	Gas	South	142.0	142.0	142.0	142.0	142.0	142.0
Rio Nogales 4	RIONOG_ST1	Guadalupe	Gas	South	323.0	323.0	323.0	323.0	323.0	323.0
Sam Bertron 1	SRB_SRB_G1	Harris	Gas	Houston	174.0	174.0	174.0	174.0	174.0	174.0
Sam Bertron 2	SRB_SRB_G2	Harris	Gas	Houston	174.0	174.0	174.0	174.0	174.0	174.0
Sam Bertron 3	SRB_SRB_G3	Harris	Gas	Houston	230.0	230.0	230.0	230.0	230.0	230.0
Sam Bertron 4	SRB_SRB_G4	Harris	Gas	Houston	230.0	230.0	230.0	230.0	230.0	230.0
Sam Bertron T2	SRB_SRBGT_2	Harris	Gas	Houston	13.0	13.0	13.0	13.0	13.0	13.0
San Jacinto SES 1	SJS_SJS_G1	Harris	Gas	Houston	81.0	81.0	81.0	81.0	81.0	81.0
San Jacinto SES 2	SJS_SJS_G2	Harris	Gas	Houston	81.0	81.0	81.0	81.0	81.0	81.0
San Miguel 1	SANMIGL_SANMIGG1	Atascosa	Coal	South	391.0	391.0	391.0	391.0	391.0	391.0
Sandhill Energy Center 1	SANDHSYD_SH1	Travis	Gas	South	45.0	45.0	45.0	45.0	45.0	45.0
Sandhill Energy Center 2	SANDHSYD_SH2	Travis	Gas	South	46.0	46.0	46.0	46.0	46.0	46.0
Sandhill Energy Center 3	SANDHSYD_SH3	Travis	Gas	South	46.0	46.0	46.0	46.0	46.0	46.0
Sandhill Energy Center 4	SANDHSYD_SH4	Travis	Gas	South	47.0	47.0	47.0	47.0	47.0	47.0
Sandhill Energy Center 5A	SANDHSYD_SH_5A	Travis	Gas	South	155.0	155.0	155.0	155.0	155.0	155.0
Sandhill Energy Center 5C	SANDHSYD_SH_5C	Travis	Gas	South	145.0	145.0	145.0	145.0	145.0	145.0
Sandow 5	SD5SES_UNIT5	Milam	Coal	South	560.0	560.0	560.0	560.0	560.0	560.0
Silas Ray 10	SILASRAY_SILAS_10	Cameron	Gas	South	48.0	48.0	48.0	48.0	48.0	48.0
Silas Ray 5	SILASRAY_SILAS_5	Cameron	Gas	South	10.0	10.0	10.0	10.0	10.0	10.0
Silas Ray 6	SILASRAY_SILAS_6	Cameron	Gas	South	20.0	20.0	20.0	20.0	20.0	20.0
Silas Ray 9	SILASRAY_SILAS_9	Cameron	Gas	South	38.0	38.0	38.0	38.0	38.0	38.0
Sim Gideon 1	GIDEON_GIDEONG1	Bastrop	Gas	South	137.0	137.0	137.0	137.0	137.0	137.0
Sim Gideon 2	GIDEON_GIDEONG2	Bastrop	Gas	South	139.0	139.0	139.0	139.0	139.0	139.0
Sim Gideon 3	GIDEON_GIDEONG3	Bastrop	Gas	South	335.0	335.0	335.0	335.0	335.0	335.0
Skyline Landfill Gas	DG_FERIS_4UNITS	Dallas	Other	North	6.4	6.4	6.4	6.4	6.4	6.4
Small Hydro of Texas 1	CUECPL_UNIT1	Dewitt	Hydro	South	1.0	1.0	1.0	1.0	1.0	1.0
South Texas 1	STP_STP_G1	Matagorda	Nuclear	Houston	1362.0	1362.0	1362.0	1362.0	1362.0	1362.0
South Texas 2	STP_STP_G2	Matagorda	Nuclear	Houston	1362.0	1362.0	1362.0	1362.0	1362.0	1362.0
Spencer 4	SPNCER_SPNCE_4	Denton	Gas	North	61.0	61.0	61.0	61.0	61.0	61.0
Spencer 5	SPNCER_SPNCE_5	Denton	Gas	North	61.0	61.0	61.0	61.0	61.0	61.0
Stryker Creek 1	SC2SES_UNIT1	Cherokee	Gas	North	174.0	174.0	174.0	174.0	174.0	174.0
Stryker Creek 2	SCSES_UNIT2	Cherokee	Gas	North	502.0	502.0	502.0	502.0	502.0	502.0
T H Wharton 3	THW_THWST_3	Harris	Gas	Houston	104.0	104.0	104.0	104.0	104.0	104.0
T H Wharton 31	THW_THWGT31	Harris	Gas	Houston	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 32	THW_THWGT32	Harris	Gas	Houston	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 33	THW_THWGT33	Harris	Gas	Houston	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 34	THW_THWGT34	Harris	Gas	Houston	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 4	THW_THWST_4	Harris	Gas	Houston	104.0	104.0	104.0	104.0	104.0	104.0
T H Wharton 41	THW_THWGT41	Harris	Gas	Houston	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 42	THW_THWGT42	Harris	Gas	Houston	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 43	THW_THWGT43	Harris	Gas	Houston	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 44	THW_THWGT44	Harris	Gas	Houston	57.0	57.0	57.0	57.0	57.0	57.0
T H Wharton 51	THW_THWGT51	Harris	Gas	Houston	58.0	58.0	58.0	58.0	58.0	58.0
T H Wharton 52	THW_THWGT52	Harris	Gas	Houston	58.0	58.0	58.0	58.0	58.0	58.0
T H Wharton 53	THW_THWGT53	Harris	Gas	Houston	58.0	58.0	58.0	58.0	58.0	58.0
T H Wharton 54	THW_THWGT54	Harris	Gas	Houston	58.0	58.0	58.0	58.0	58.0	58.0
T H Wharton 55	THW_THWGT55	Harris	Gas	Houston	58.0	58.0	58.0	58.0	58.0	58.0
T H Wharton 56	THW_THWGT56	Harris	Gas	Houston	58.0	58.0	58.0	58.0	58.0	58.0
T H Wharton G1	THW_THWGT_1	Harris	Gas	Houston	13.0	13.0	13.0	13.0	13.0	13.0
Tessman Road 1	DG_WALZE_4UNITS	Bexar	Biomass	South	10.0	10.0	10.0	10.0	10.0	10.0
Texas City 1	TXCTY_CTA	Galveston	Gas	Houston	100.0	100.0	100.0	100.0	100.0	100.0
Texas City 2	TXCTY_CTB	Galveston	Gas	Houston	93.0	93.0	93.0	93.0	93.0	93.0
Texas City 3	TXCTY_CTC	Galveston	Gas	Houston	93.0	93.0	93.0	93.0	93.0	93.0
Texas City 4	TXCTY_ST	Galveston	Gas	Houston	128.0	128.0	128.0	128.0	128.0	128.0
Texas Gulf Sulphur	TGF_TGFGT_1	Wharton	Gas	Houston	70.0	70.0	70.0	70.0	70.0	70.0
Thomas C Ferguson 1	FERGUS_FERGUSG1	Llano	Gas	South	424.0	424.0	424.0	424.0	424.0	424.0
Tradinghouse 2	THSES_UNIT2	Mclennan	Gas	North	787.0	787.0	787.0	787.0	787.0	787.0
Trinidad 6	TRSES_UNIT6	Henderson	Gas	North	230.0	230.0	230.0	230.0	230.0	230.0
Trinity Oaks LFG	DG_KLBRG_1UNIT	Dallas	Biomass	North	3.2	3.2	3.2	3.2	3.2	3.2
Twin Oaks 1	TNP_ONE_TNP_O_1	Robertson	Coal	North	156.0	156.0	156.0	156.0	156.0	156.0
Twin Oaks 2	TNP_ONE_TNP_O_2	Robertson	Coal	North	156.0	156.0	156.0	156.0	156.0	156.0
V H Braunig 1	BRAUNIG_VHB1	Bexar	Gas	South	215.0	215.0	215.0	215.0	215.0	215.0
V H Braunig 2	BRAUNIG_VHB2	Bexar	Gas	South	220.0	220.0	220.0	220.0	220.0	220.0
V H Braunig 3	BRAUNIG_VHB3	Bexar	Gas	South	397.0	397.0	397.0	397.0	397.0	397.0
Valley 1	VLSES_UNIT1	Fannin	Gas	North	174.0	174.0	174.0	174.0	174.0	174.0
Valley 2	VLSES_UNIT2	Fannin	Gas	North	520.0	520.0	520.0	520.0	520.0	520.0
Valley 3	VLSES_UNIT3	Fannin	Gas	North	375.0	375.0	375.0	375.0	375.0	375.0
Victoria Power Station 5	VICTORIA_VICTORG5	Victoria	Gas	South	133.0	133.0	133.0	133.0	133.0	133.0
Victoria Power Station 6	VICTORIA_VICTORG6	Victoria	Gas	South	164.0	164.0	164.0	164.0	164.0	164.0

Unit Capacities - Summer

Units used in determining the generation resources in the Summer Summary

Operational capacities are based on unit testing. Other capacities are based on information provided by the plant owners. This list includes MW available to the grid from private network (self-serve) units. It also includes distributed generation units that have registered with ERCOT. Data without unit names are for private network units or are planned generation that is not public.

Unit Name	Unit Code	County	Fuel	CM Zone	2010	2011	2012	2013	2014	2015
W A Parish 1	WAP_WAP_G1	Ft. Bend	Gas	Houston	174.0	174.0	174.0	174.0	174.0	174.0
W A Parish 2	WAP_WAP_G2	Ft. Bend	Gas	Houston	174.0	174.0	174.0	174.0	174.0	174.0
W A Parish 3	WAP_WAP_G3	Ft. Bend	Gas	Houston	278.0	278.0	278.0	278.0	278.0	278.0
W A Parish 4	WAP_WAP_G4	Ft. Bend	Gas	Houston	552.0	552.0	552.0	552.0	552.0	552.0
W A Parish 5	WAP_WAP_G5	Ft. Bend	Coal	Houston	645.0	645.0	645.0	645.0	645.0	645.0
W A Parish 6	WAP_WAP_G6	Ft. Bend	Coal	Houston	650.0	650.0	650.0	650.0	650.0	650.0
W A Parish 7	WAP_WAP_G7	Ft. Bend	Coal	Houston	565.0	565.0	565.0	565.0	565.0	565.0
W A Parish 8	WAP_WAP_G8	Ft. Bend	Coal	Houston	600.0	600.0	600.0	600.0	600.0	600.0
W A Parish T1	WAP_WAPGT_1	Ft. Bend	Gas	Houston	13.0	13.0	13.0	13.0	13.0	13.0
Whitney 1	WND_WHITNEY1	Bosque	Hydro	North	15.0	15.0	15.0	15.0	15.0	15.0
Whitney 2	WND_WHITNEY2	Bosque	Hydro	North	15.0	15.0	15.0	15.0	15.0	15.0
Wichita Falls 1	WFCOGEN_UNIT1	Wichita	Gas	North	20.0	20.0	20.0	20.0	20.0	20.0
Wichita Falls 2	WFCOGEN_UNIT2	Wichita	Gas	North	20.0	20.0	20.0	20.0	20.0	20.0
Wichita Falls 3	WFCOGEN_UNIT3	Wichita	Gas	North	20.0	20.0	20.0	20.0	20.0	20.0
Wichita Falls 4	WFCOGEN_UNIT4	Wichita	Gas	North	17.0	17.0	17.0	17.0	17.0	17.0
Winchester Power Park 1	WIPOPA_WPP_G1	Fayette	Gas	South	45.0	45.0	45.0	45.0	45.0	45.0
Winchester Power Park 2	WIPOPA_WPP_G2	Fayette	Gas	South	45.0	45.0	45.0	45.0	45.0	45.0
Winchester Power Park 3	WIPOPA_WPP_G3	Fayette	Gas	South	45.0	45.0	45.0	45.0	45.0	45.0
Winchester Power Park 4	WIPOPA_WPP_G4	Fayette	Gas	South	45.0	45.0	45.0	45.0	45.0	45.0
Wise-Tractebel Power Proj. 1	WCPP_CT1	Wise	Gas	North	212.0	212.0	212.0	212.0	212.0	212.0
Wise-Tractebel Power Proj. 2	WCPP_CT2	Wise	Gas	North	212.0	212.0	212.0	212.0	212.0	212.0
Wise-Tractebel Power Proj. 3	WCPP_ST1	Wise	Gas	North	241.0	241.0	241.0	241.0	241.0	241.0
Wolf Hollow Power Proj. 1	WHCCS_CT1	Hood	Gas	North	212.0	212.0	212.0	212.0	212.0	212.0
Wolf Hollow Power Proj. 2	WHCCS_CT2	Hood	Gas	North	212.0	212.0	212.0	212.0	212.0	212.0
Wolf Hollow Power Proj. 3	WHCCS_STG	Hood	Gas	North	280.0	280.0	280.0	280.0	280.0	280.0
Operational					**64,940**	**64,940**	**64,940**	**64,940**	**64,940**	**64,940**
					12.0	12.0	12.0	12.0	12.0	12.0
					0.0	0.0	0.0	0.0	0.0	0.0
					661.0	661.0	661.0	661.0	661.0	661.0
					74.0	74.0	74.0	74.0	74.0	74.0
					565.0	565.0	565.0	565.0	565.0	565.0
					300.0	300.0	300.0	300.0	300.0	300.0
					166.0	166.0	166.0	166.0	166.0	166.0
					18.0	18.0	18.0	18.0	18.0	18.0
					341.0	341.0	341.0	341.0	341.0	341.0
					0.0	0.0	0.0	0.0	0.0	0.0
					269.0	269.0	269.0	269.0	269.0	269.0
					10.0	0.0	0.0	0.0	0.0	0.0
					280.0	280.0	280.0	280.0	280.0	280.0
					215.0	215.0	215.0	215.0	215.0	215.0
					0.0	0.0	0.0	0.0	0.0	0.0
					0.0	0.0	0.0	0.0	0.0	0.0
					50.0	50.0	50.0	50.0	50.0	50.0
					31.0	56.0	56.0	56.0	56.0	56.0
					400.0	400.0	400.0	400.0	400.0	400.0
					360.0	360.0	360.0	360.0	360.0	360.0
					110.0	110.0	110.0	110.0	110.0	110.0
					25.0	25.0	25.0	25.0	25.0	25.0
					6.0	6.0	6.0	6.0	6.0	6.0
					485.0	485.0	485.0	485.0	485.0	485.0
					325.0	325.0	325.0	325.0	325.0	325.0
					596.0	596.0	596.0	596.0	596.0	596.0
					3.0	3.0	3.0	3.0	3.0	3.0
					15.0	15.0	15.0	15.0	15.0	15.0
					0.0	10.0	10.0	10.0	10.0	10.0
					1.0	1.0	1.0	1.0	1.0	1.0
Generation from Private Use Networks					**5,318.0**	**5,343.0**	**5,343.0**	**5,343.0**	**5,343.0**	**5,343.0**
Permian Basin 5	PB5SES_UNIT5	Ward	Gas	West	112.0	0.0	0.0	0.0	0.0	0.0
Permian Basin 6	PBSES_UNIT6	Ward	Gas	West	515.0	0.0	0.0	0.0	0.0	0.0
RMR					**627.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Eagle Pass	DC Tie	Maverick	Other	South	36.0	36.0	36.0	36.0	36.0	36.0
East	DC Tie	Fannin	Other	North	600.0	600.0	600.0	600.0	600.0	600.0
Laredo VFT	DC Tie	Webb	Other	South	100.0	100.0	100.0	100.0	100.0	100.0
North	DC Tie	Wilbarger	Other	West	220.0	220.0	220.0	220.0	220.0	220.0
Sharyland	DC Tie	Hidalgo	Other	South	150.0	150.0	150.0	150.0	150.0	150.0
DC-Ties					**1,106.0**	**1,106.0**	**1,106.0**	**1,106.0**	**1,106.0**	**1,106.0**
Kiamichi Energy Facility 1CT101	KMCHI_1CT101	Pittsburg	Gas	North	142.0	142.0	142.0	142.0	142.0	142.0

Unit Capacities - Summer

Units used in determining the generation resources in the Summer Summary

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Unit Name	Unit Code	County	Fuel	CM Zone	2010	2011	2012	2013	2014	2015
Kiamichi Energy Facility 1CT201	KMCHI_1CT201	Pittsburg	Gas	North	144.0	144.0	144.0	144.0	144.0	144.0
Kiamichi Energy Facility 1ST	KMCHI_1ST	Pittsburg	Gas	North	310.0	310.0	310.0	310.0	310.0	310.0
Kiamichi Energy Facility 2CT101	KMCHI_2CT101	Pittsburg	Gas	North	136.0	136.0	136.0	136.0	136.0	136.0
Kiamichi Energy Facility 2CT201	KMCHI_2CT201	Pittsburg	Gas	North	138.0	138.0	138.0	138.0	138.0	138.0
Kiamichi Energy Facility 2ST	KMCHI_2ST	Pittsburg	Gas	North	303.0	303.0	303.0	303.0	303.0	303.0
Tenaska-Frontier 1	FTR_FTR_G1	Grimes	Gas	North	156.0	156.0	156.0	156.0	156.0	156.0
Tenaska-Frontier 2	FTR_FTR_G2	Grimes	Gas	North	159.0	159.0	159.0	159.0	159.0	159.0
Tenaska-Frontier 3	FTR_FTR_G3	Grimes	Gas	North	158.0	158.0	158.0	158.0	158.0	158.0
Tenaska-Frontier 4	FTR_FTR_G4	Grimes	Gas	North	380.0	380.0	380.0	380.0	380.0	380.0
Tenaska-Gateway 1	TGCCS_CT1	Rusk	Gas	North	149.0	149.0	149.0	149.0	149.0	149.0
Tenaska-Gateway 2	TGCCS_CT2	Rusk	Gas	North	128.0	128.0	128.0	128.0	128.0	128.0
Tenaska-Gateway 3	TGCCS_CT3	Rusk	Gas	North	146.0	146.0	146.0	146.0	146.0	146.0
Tenaska-Gateway 4	TGCCS_UNIT4	Rusk	Gas	North	399.0	399.0	399.0	399.0	399.0	399.0
Switchable Resources					**2,848.0**	**2,848.0**	**2,848.0**	**2,848.0**	**2,848.0**	**2,848.0**
Barton Chapel Wind	BRTSW_BCW1	Jack	Wind	North	120.0	120.0	120.0	120.0	120.0	120.0
Buffalo Gap Wind Farm 1	BUFF_GAP_UNIT1	Taylor	Wind	West	120.0	120.0	120.0	120.0	120.0	120.0
Buffalo Gap Wind Farm 2	BUFF_GAP_UNIT2	Taylor	Wind	West	233.0	233.0	233.0	233.0	233.0	233.0
Buffalo Gap Wind Farm 3	BUFF_GAP_UNIT3	Taylor	Wind	West	150.0	150.0	150.0	150.0	150.0	150.0
Bull Creek Wind Plant	BULLCRK_WND1	Borden	Wind	West	91.0	91.0	91.0	91.0	91.0	91.0
Bull Creek Wind Plant	BULLCRK_WND2	Borden	Wind	West	89.0	89.0	89.0	89.0	89.0	89.0
Callahan Wind	CALLAHAN_WND1	Callahan	Wind	West	114.0	114.0	114.0	114.0	114.0	114.0
Camp Springs 1	CSEC_CSECG1	Scurry	Wind	West	130.0	130.0	130.0	130.0	130.0	130.0
Camp Springs 2	CSEC_CSECG2	Scurry	Wind	West	120.0	120.0	120.0	120.0	120.0	120.0
Capricorn Ridge Wind 1	CAPRIDGE_CR1	Sterling	Wind	West	200.0	200.0	200.0	200.0	200.0	200.0
Capricorn Ridge Wind 2	CAPRIDGE_CR3	Sterling	Wind	West	186.0	186.0	186.0	186.0	186.0	186.0
Capricorn Ridge Wind 3	CAPRIDGE_CR2	Sterling	Wind	West	140.0	140.0	140.0	140.0	140.0	140.0
Capricorn Ridge Wind 4	CAPRIDG4_CR4	Sterling	Wind	West	115.0	115.0	115.0	115.0	115.0	115.0
Champion Wind Farm	TKWSW_CHAMPION	Nolan	Wind	West	120.0	120.0	120.0	120.0	120.0	120.0
Delaware Mountain Wind Farm	DELAWARE_WIND_NWP	Culberson	Wind	West	30.0	30.0	30.0	30.0	30.0	30.0
Desert Sky Wind Farm 1	INDNENR_INDNENR	Pecos	Wind	West	25.0	25.0	25.0	25.0	25.0	25.0
Desert Sky Wind Farm 2	INDNENR_INDNENR_2	Pecos	Wind	West	135.0	135.0	135.0	135.0	135.0	135.0
Elbow Creek Wind Project	ELB_ELBCREEK	Howard	Wind	West	117.0	117.0	117.0	117.0	117.0	117.0
Forest Creek Wind Farm	MCDLD_FCW1	Glasscock	Wind	West	124.0	124.0	124.0	124.0	124.0	124.0
Goat Wind	GOAT_GOATWIND	Sterling	Wind	West	150.0	150.0	150.0	150.0	150.0	150.0
Green Mountain Energy 1	BRAZ_WND_WND1	Scurry	Wind	West	99.0	99.0	99.0	99.0	99.0	99.0
Green Mountain Energy 2	BRAZ_WND_WND2	Scurry	Wind	West	61.0	61.0	61.0	61.0	61.0	61.0
Gulf Wind I	TGW_T1	Kenedy	Wind	South	143.0	143.0	143.0	143.0	143.0	143.0
Gulf Wind II	TGW_T2	Kenedy	Wind	South	140.0	140.0	140.0	140.0	140.0	140.0
Hackberry Wind Farm	HWF_HWFG1	Shackelford	Wind	North	165.0	165.0	165.0	165.0	165.0	165.0
Horse Hollow Wind 1	H_HOLLOW_WND1	Taylor	Wind	West	210.0	210.0	210.0	210.0	210.0	210.0
Horse Hollow Wind 2	HHOLLOW4_WND1	Taylor	Wind	West	115.0	115.0	115.0	115.0	115.0	115.0
Horse Hollow Wind 3	HHOLLOW3_WND_1	Taylor	Wind	West	220.0	220.0	220.0	220.0	220.0	220.0
Horse Hollow Wind 4	HHOLLOW2_WIND1	Taylor	Wind	West	180.0	180.0	180.0	180.0	180.0	180.0
Inadale Wind	INDL_INADALE1	Nolan	Wind	West	197.0	197.0	197.0	197.0	197.0	197.0
Indian Mesa Wind Farm	INDNNWP_INDNNWP	Pecos	Wind	West	80.0	80.0	80.0	80.0	80.0	80.0
King Mountain NE	KING_NE_KINGNE	Upton	Wind	West	80.0	80.0	80.0	80.0	80.0	80.0
King Mountain NW	KING_NW_KINGNW	Upton	Wind	West	80.0	80.0	80.0	80.0	80.0	80.0
King Mountain SE	KING_SE_KINGSE	Upton	Wind	West	43.0	43.0	43.0	43.0	43.0	43.0
King Mountain SW	KING_SW_KINGSW	Upton	Wind	West	80.0	80.0	80.0	80.0	80.0	80.0
Kunitz Wind	KUNITZ_WIND_LGE	Culberson	Wind	West	35.0	35.0	35.0	35.0	35.0	35.0
Langford Wind Power	LGD_LANGFORD	Tom Green	Wind	West	150.0	150.0	150.0	150.0	150.0	150.0
Loraine Windpark I	LONEWOLF_G1	Mitchell	Wind	West	126.0	126.0	126.0	126.0	126.0	126.0
Loraine Windpark II	LONEWOLF_G2	Mitchell	Wind	West	125.0	125.0	125.0	125.0	125.0	125.0
McAdoo Wind Farm	MWEC_G1	Dickens	Wind	West	150.0	150.0	150.0	150.0	150.0	150.0
Mesquite Wind	LNCRK_G83	Shackelford	Wind	North	200.0	200.0	200.0	200.0	200.0	200.0
Notrees-1	NWF_NWF1	Winkler	Wind	West	153.0	153.0	153.0	153.0	153.0	153.0
Ocotillo Wind Farm	OWF_OWF	Howard	Wind	West	59.0	59.0	59.0	59.0	59.0	59.0
Panther Creek 1	PC_NORTH_PANTHER1	Howard	Wind	West	143.0	143.0	143.0	143.0	143.0	143.0
Panther Creek 2	PC_SOUTH_PANTHER2	Howard	Wind	West	115.0	115.0	115.0	115.0	115.0	115.0
Pecos Wind (Woodward 1)	WOODWRD1_WOODWRD1	Pecos	Wind	West	80.0	80.0	80.0	80.0	80.0	80.0
Pecos Wind (Woodward 2)	WOODWRD2_WOODWRD2	Pecos	Wind	West	80.0	80.0	80.0	80.0	80.0	80.0
Penascal Wind	PENA_UNIT1	Kenedy	Wind	South	101.0	101.0	101.0	101.0	101.0	101.0
Penascal Wind	PENA_UNIT2	Kenedy	Wind	South	101.0	101.0	101.0	101.0	101.0	101.0
Post Oak Wind 1	LNCRK2_G871	Shackelford	Wind	North	100.0	100.0	100.0	100.0	100.0	100.0
Post Oak Wind 2	LNCRK2_G872	Shackelford	Wind	North	100.0	100.0	100.0	100.0	100.0	100.0
Pyron Wind Farm	PYR_PYRON1	Scurry	Wind	West	249.0	249.0	249.0	249.0	249.0	249.0
Red Canyon	RDCANYON_RDCNY1	Borden	Wind	West	84.0	84.0	84.0	84.0	84.0	84.0
Roscoe Wind Farm	TKWSW1_ROSCOE	Nolan	Wind	West	200.0	200.0	200.0	200.0	200.0	200.0
Sand Bluff Wind Farm	MCDLD_SBW1	Glasscock	Wind	West	90.0	90.0	90.0	90.0	90.0	90.0
Sherbino I	KEO_KEO_SM1	Pecos	Wind	West	150.0	150.0	150.0	150.0	150.0	150.0

Unit Capacities - Summer

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Unit Name	Unit Code	County	Fuel	CM Zone	2010	2011	2012	2013	2014	2015
Silver Star	FLTCK_SSI	Eastland	Wind	North	60.0	60.0	60.0	60.0	60.0	60.0
Snyder Wind Farm	ENAS_ENA1	Scurry	Wind	West	63.0	63.0	63.0	63.0	63.0	63.0
South Trent Wind Farm	STWF_T1	Nolan	Wind	West	98.0	98.0	98.0	98.0	98.0	98.0
Stanton Wind Energy	SWEC_G1	Martin	Wind	West	120.0	120.0	120.0	120.0	120.0	120.0
Sweetwater Wind 1	SWEETWND_WND1	Nolan	Wind	West	37.0	37.0	37.0	37.0	37.0	37.0
Sweetwater Wind 2	SWEETWN2_WND24	Nolan	Wind	West	16.0	16.0	16.0	16.0	16.0	16.0
Sweetwater Wind 3	SWEETWN2_WND2	Nolan	Wind	West	100.0	100.0	100.0	100.0	100.0	100.0
Sweetwater Wind 4	SWEETWN3_WND3	Nolan	Wind	West	130.0	130.0	130.0	130.0	130.0	130.0
Sweetwater Wind 5	SWEETWN4_WND5	Nolan	Wind	West	80.0	80.0	80.0	80.0	80.0	80.0
Sweetwater Wind 6	SWEETWN4_WND4B	Nolan	Wind	West	105.0	105.0	105.0	105.0	105.0	105.0
Sweetwater Wind 7	SWEETWN4_WND4A	Nolan	Wind	West	119.0	119.0	119.0	119.0	119.0	119.0
Texas Big Spring	SGMTN_SIGNALMT	Howard	Wind	West	40.0	40.0	40.0	40.0	40.0	40.0
Trent Wind Farm	TRENT_TRENT	Nolan	Wind	West	150.0	150.0	150.0	150.0	150.0	150.0
TSTC West Texas Wind	DG_ROSC2_1UNIT	Nolan	Wind	West	2.0	2.0	2.0	2.0	2.0	2.0
Turkey Track Wind Energy Center	TTWEC_G1	Nolan	Wind	West	170.0	170.0	170.0	170.0	170.0	170.0
West Texas Wind Energy	SW_MESA_SW_MESA	Upton	Wind	West	70.0	70.0	70.0	70.0	70.0	70.0
Whirlwind Energy	WEC_WECG1	Floyd	Wind	West	60.0	60.0	60.0	60.0	60.0	60.0
Wolfe Flats	DG_TURL_UNIT1	Hall	Wind	West	10.0	10.0	10.0	10.0	10.0	10.0
Wolfe Ridge	WHTTAIL_WR1	Cooke	Wind	North	113.0	113.0	113.0	113.0	113.0	113.0
Papalote Creek Wind Farm	PAP1_PAP1	San Patricio	Wind	South	180.0	180.0	180.0	180.0	180.0	180.0
Panther Creek 3	PC_SOUTH_PANTHER3	Howard	Wind	West	200.0	200.0	200.0	200.0	200.0	200.0
WIND					**8,916**	**8,916**	**8,916**	**8,916**	**8,916**	**8,916**
Cedro Hill Wind	09INR0082	Webb	Wind		150.0	150.0	150.0	150.0	150.0	150.0
Sherbino Mesa Wind Farm 2	06INR0012b	Pecos	Wind		150.0	150.0	150.0	150.0	150.0	150.0
Senate Wind Project	08INR0011	Jack	Wind		0.0	150.0	150.0	150.0	150.0	150.0
Cedar Elm	04INR0011b	Shackelford	Wind		0.0	136.0	136.0	136.0	136.0	136.0
Penascal Wind Farm 2	06INR0022c	Kenedy	Wind		0.0	202.0	202.0	202.0	202.0	202.0
Gunsight Mountain	08INR0018	Howard	Wind		0.0	0.0	120.0	120.0	120.0	120.0
Cottonwood Wind	04INR0011c	Shackelford	Wind		0.0	0.0	100.0	100.0	100.0	100.0
Wild Horse Mountain	06INR0026	Howard	Wind		0.0	0.0	120.0	120.0	120.0	120.0
Penascal Wind Farm 3	06INR0022b	Kenedy	Wind		0.0	0.0	202.0	202.0	202.0	202.0
Sterling Energy Center	09INR0026	Sterling	Wind		0.0	0.0	300.0	300.0	300.0	300.0
Lenorah Project	08INR0040	Martin	Wind		0.0	0.0	0.0	251.0	251.0	251.0
New Wind Generation					**300.0**	**788.0**	**1,630.0**	**1,881.0**	**1,881.0**	**1,881.0**
V H Braunig 6	09INR0028	Bexar	Gas		185.0	185.0	185.0	185.0	185.0	185.0
TECO Central Plant	11INR0014	Harris	Gas		50.0	50.0	50.0	50.0	50.0	50.0
Lufkin	08INR0033	Angelina	Biomass		45.0	45.0	45.0	45.0	45.0	45.0
Oak Grove SES 2	09INR0006b	Robertson	Coal		855.0	855.0	855.0	855.0	855.0	855.0
Pearsall Engine Phase II	09INR0079b	Frio	Gas		100.0	100.0	100.0	100.0	100.0	100.0
Sand Hill Peakers	09INR0045	Travis	Gas		94.0	94.0	94.0	94.0	94.0	94.0
CFB Power Plant Units 11&12	09INR0029	Calhoun	Coal		0.0	263.0	263.0	263.0	263.0	263.0
Jack County 2	10INR0010	Jack	Gas		0.0	620.0	620.0	620.0	620.0	620.0
Nacogdoches Project	09INR0007	Nacogdoches	Biomass		0.0	0.0	100.0	100.0	100.0	100.0
Sandy Creek 1	09INR0001	McLennan	Coal		0.0	0.0	925.0	925.0	925.0	925.0
New Units with Signed IA and Air Permit					**1,329.0**	**2,212.0**	**3,237.0**	**3,237.0**	**3,237.0**	**3,237.0**
Atkins 3	ATKINS_ATKINSG3	Brazos	Gas	North	12.0	12.0	12.0	12.0	12.0	12.0
Atkins 4	ATKINS_ATKINSG4	Brazos	Gas	North	22.0	22.0	22.0	22.0	22.0	22.0
Atkins 5	ATKINS_ATKINSG5	Brazos	Gas	North	25.0	25.0	25.0	25.0	25.0	25.0
Atkins 6	ATKINS_ATKINSG6	Brazos	Gas	North	50.0	50.0	50.0	50.0	50.0	50.0
C E Newman 5	NEWMAN_NEWMA_5	Dallas	Gas	North	37.0	37.0	37.0	37.0	37.0	37.0
Collin 1	CNSES_UNIT1	Collin	Gas	North	147.0	147.0	147.0	147.0	147.0	147.0
W B Tuttle 1	TUTTLE_WBT1G1	Bexar	Gas	South	61.0	61.0	61.0	61.0	61.0	61.0
W B Tuttle 3	TUTTLE_WBT3G3	Bexar	Gas	South	90.0	90.0	90.0	90.0	90.0	90.0
W B Tuttle 4	TUTTLE_WBT4G4	Bexar	Gas	South	154.0	154.0	154.0	154.0	154.0	154.0
DeCordova 1	DC3SES_UNIT1	Hood	Gas	North	816.0	816.0	816.0	816.0	816.0	816.0
Eagle Mountain 1	EMSES_UNIT1	Tarrant	Gas	North	118.0	118.0	118.0	118.0	118.0	118.0
Eagle Mountain 2	EMSES_UNIT2	Tarrant	Gas	North	100.0	100.0	100.0	100.0	100.0	100.0
Eagle Mountain 3	EMSES_UNIT3	Tarrant	Gas	North	390.0	390.0	390.0	390.0	390.0	390.0
Lake Creek 1	LCSES_UNIT1	Mclennan	Gas	North	81.0	81.0	81.0	81.0	81.0	81.0
Lake Creek 2	LCSES_UNIT2	Mclennan	Gas	North	239.0	239.0	239.0	239.0	239.0	239.0
Permian Basin 5	PB5SES_UNIT5	Ward	Gas	West	112.0	112.0	112.0	112.0	112.0	112.0
Permian Basin 6	PBSES_UNIT6	Ward	Gas	West	515.0	515.0	515.0	515.0	515.0	515.0
J L Bates 1	BATES_BATES_G1	Hidalgo	Gas	South	75.0	75.0	75.0	75.0	75.0	75.0
J L Bates 2	BATES_BATES_G2	Hidalgo	Gas	South	113.7	113.7	113.7	113.7	113.7	113.7
Mothballed Resources					**3,157.7**	**3,157.7**	**3,157.7**	**3,157.7**	**3,157.7**	**3,157.7**

Unit Capacities - Summer

Units used in determining the generation resources in the Summer Summary

Operational capacities are based on unit testing. Other capacities are based on information provided by the plant owners. This list includes MW available to the grid from private network (self-serve) units. It also includes distributed generation units that have registered with ERCOT. Data without unit names are for private network units or are planned generation that is not public.

Unit Name	Unit Code	County	Fuel	CM Zone	2010	2011	2012	2013	2014	2015
Panda Temple Power	10INR0020	Bell	Gas		0.0	1092.0	1092.0	1092.0	1092.0	1092.0
Pampa Energy Center	07INR0004	Gray	Coal		0.0	0.0	165.0	165.0	165.0	165.0
Comanche Peak 3 and 4	15INR0002	Somervel	Nuclear		0.0	0.0	0.0	0.0	0.0	3200.0
STP 3 and 4	15INR0008	Matagorda	Nuclear		0.0	0.0	0.0	0.0	0.0	2700.0
Potential Public Non-Wind Resources					**0.0**	**1092.0**	**1257.0**	**1257.0**	**1257.0**	**7157.0**

Unit Name	Unit Code	County	Fuel	CM Zone	2010	2011	2012	2013	2014	2015
Gatesville Wind Farm	09INR0034	Coryell	Wind		200.0	200.0	200.0	200.0	200.0	200.0
M Bar Wind	08INR0038	Andrews	Wind		194.0	194.0	194.0	194.0	194.0	194.0
Scurry County Wind III	09INR0037	Scurry	Wind		350.0	350.0	350.0	350.0	350.0	350.0
Papalote Creek Phase 2	08INR0012b	San Patricio	Wind		151.0	151.0	151.0	151.0	151.0	151.0
Gulf Wind 3	05INR0015c	Kenedy	Wind		0.0	400.0	400.0	400.0	400.0	400.0
Gulf Wind 2	05INR0015b	Kenedy	Wind		0.0	400.0	400.0	400.0	400.0	400.0
Throckmorton Wind Farm	12INR0003	Throckmorton	Wind		0.0	400.0	400.0	400.0	400.0	400.0
Buffalo Gap 4 and 5	08INR0065	Nolan	Wind		0.0	465.0	465.0	465.0	465.0	465.0
Pistol Hill Energy Center	08INR0025	Ector	Wind		0.0	0.0	300.0	300.0	300.0	300.0
B&B Panhandle Wind	09INR0024	Carson	Wind		0.0	0.0	1001.0	1001.0	1001.0	1001.0
Sterling Energy Center	09INR0026a	Sterling	Wind		0.0	0.0	200.0	200.0	200.0	200.0
Fort Concho Wind Farm	12INR0004	Tom Green	Wind		0.0	0.0	400.0	400.0	400.0	400.0
McAdoo Energy Center II	09INR0036	Dickens	Wind		0.0	0.0	0.0	500.0	500.0	500.0
Potential Public Wind Resources					**895.0**	**2,560.0**	**4,461.0**	**4,961.0**	**4,961.0**	**4,961.0**

Unit Name	Unit Code	County	Fuel	CM Zone	2010	2011	2012	2013	2014	2015
	10INR0011	Johnson	Gas		275.0	275.0	275.0	275.0	275.0	275.0
	10INR0069	Rusk	Coal		13.0	13.0	13.0	13.0	13.0	13.0
	09INR0081	Rusk	Coal		18.0	18.0	18.0	18.0	18.0	18.0
	10INR0029	Hood	Gas		810.0	810.0	810.0	810.0	810.0	810.0
	10INR0035	Harris	Gas		416.0	416.0	416.0	416.0	416.0	416.0
	10INR0012	Nacogdoches	Gas		300.0	300.0	300.0	300.0	300.0	300.0
	10INR0070	Hunt	Gas		0.0	50.0	50.0	50.0	50.0	50.0
	09INR0031	Ector	Gas		0.0	275.0	275.0	275.0	275.0	275.0
	10INR0032	Navarro	Gas		0.0	775.0	775.0	775.0	775.0	775.0
	10INR0080	Presidio	Solar		0.0	144.0	144.0	144.0	144.0	144.0
	11INR0037	Smith	Biomass		0.0	50.0	50.0	50.0	50.0	50.0
	11INR0028	Grimes	Gas		0.0	1280.0	1280.0	1280.0	1280.0	1280.0
	11INR0046	Brazoria	Gas		0.0	300.0	300.0	300.0	300.0	300.0
	11INR0048	Harris	Gas		0.0	300.0	300.0	300.0	300.0	300.0
	11INR0058	Pecos	Solar		0.0	135.0	135.0	135.0	135.0	135.0
	11INR0060	Tom Green	Solar		0.0	90.0	90.0	90.0	90.0	90.0
	11INR0061	Presidio	Solar		0.0	90.0	90.0	90.0	90.0	90.0
	09INR0050	Fannin	Gas		0.0	1200.0	1200.0	1200.0	1200.0	1200.0
	11INR0006	Lamar	Gas		0.0	579.0	579.0	579.0	579.0	579.0
	11INR0040	freestone	Gas		0.0	0.0	640.0	640.0	640.0	640.0
	10INR0021	Grayson	Gas		0.0	0.0	646.0	646.0	646.0	646.0
	10INR0018	Madison	Gas		0.0	0.0	550.0	550.0	550.0	550.0
	11INR0049	Wharton	Gas		0.0	0.0	275.0	275.0	275.0	275.0
	12INR0007	Lamar	Gas		0.0	0.0	296.0	296.0	296.0	296.0
	12INR0006	Limestone	Coal		0.0	0.0	875.0	875.0	875.0	875.0
	10INR0022	Harris	Gas		0.0	0.0	3500.0	3500.0	3500.0	3500.0
	12INR0016	Nueces	Other		0.0	0.0	0.0	1200.0	1200.0	1200.0
	14INR0002	Goliad	Coal		0.0	0.0	0.0	0.0	756.0	756.0
	14INR0003	Nolan	Coal		0.0	0.0	0.0	0.0	850.0	850.0
	14INR0005	Matagorda	Coal		0.0	0.0	0.0	0.0	1200.0	1200.0
Potential Confidential Non-Wind Resources					**1,832.0**	**7,100.0**	**13,882.0**	**15,082.0**	**17,888.0**	**17,888.0**

Unit Name	Unit Code	County	Fuel	CM Zone	2010	2011	2012	2013	2014	2015
	08INR0049	Clay	Wind		50.0	50.0	50.0	50.0	50.0	50.0
	09INR0073	Scurry	Wind		200.0	200.0	200.0	200.0	200.0	200.0
	08INR0022	Floyd	Wind		100.0	100.0	100.0	100.0	100.0	100.0
	08INR0023	Floyd	Wind		100.0	100.0	100.0	100.0	100.0	100.0
	08INR0039	Hamilton	Wind		90.0	90.0	90.0	90.0	90.0	90.0
	08INR0056	Nolan	Wind		149.0	149.0	149.0	149.0	149.0	149.0
	09INR0051	Borden	Wind		249.0	249.0	249.0	249.0	249.0	249.0
	09INR0054	Stonewall	Wind		148.5	148.5	148.5	148.5	148.5	148.5
	09INR0061	Kent	Wind		258.0	258.0	258.0	258.0	258.0	258.0
	09INR0058	Howard	Wind		250.0	250.0	250.0	250.0	250.0	250.0
	09INR0065	Webb	Wind		150.0	150.0	150.0	150.0	150.0	150.0
	11INR0012	Duval	Wind		400.0	400.0	400.0	400.0	400.0	400.0
	11INR0013	Mills	Wind		150.0	150.0	150.0	150.0	150.0	150.0
	09INR0077	Reagan	Wind		500.0	500.0	500.0	500.0	500.0	500.0
	10INR0024	Briscoe	Wind		2940.0	2940.0	2940.0	2940.0	2940.0	2940.0
	10INR0048	Hardeman	Wind		1000.0	1000.0	1000.0	1000.0	1000.0	1000.0
	11INR0033a	Cameron	Wind		200.0	200.0	200.0	200.0	200.0	200.0
	10INR0045	Webb	Wind		734.0	734.0	734.0	734.0	734.0	734.0

Unit Capacities - Summer

Units used in determining the generation resources in the Summer Summary

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Unit Name	Unit Code	County	Fuel	CM Zone	2010	2011	2012	2013	2014	2015
	10INR0046	Jim Hogg	Wind		264.0	264.0	264.0	264.0	264.0	264.0
	09INR0018	Concho	Wind		249.0	249.0	249.0	249.0	249.0	249.0
	09INR0035	Concho	Wind		750.0	750.0	750.0	750.0	750.0	750.0
	07INR0032	Tom Green	Wind		249.0	249.0	249.0	249.0	249.0	249.0
	10INR0016	Childress	Wind		150.0	150.0	150.0	150.0	150.0	150.0
	10INR0023	Haskell	Wind		386.0	386.0	386.0	386.0	386.0	386.0
	09INR0069	Reagan	Wind		36.0	36.0	36.0	36.0	36.0	36.0
	09INR0070	Reagan	Wind		42.0	42.0	42.0	42.0	42.0	42.0
	10INR0054	Palo Pinto	Wind		36.0	36.0	36.0	36.0	36.0	36.0
	10INR0062a	Pecos	Wind		49.5	49.5	49.5	49.5	49.5	49.5
	10INR0079	Nolan	Wind		60.0	60.0	60.0	60.0	60.0	60.0
	10INR0013	Upton	Wind		400.0	400.0	400.0	400.0	400.0	400.0
	10INR0052a	Knox	Wind		21.0	21.0	21.0	21.0	21.0	21.0
	10INR0057	Taylor	Wind		200.0	200.0	200.0	200.0	200.0	200.0
	10INR0071	Matagorda	Wind		0.0	88.0	88.0	88.0	88.0	88.0
	10INR0015	Mitchell	Wind		0.0	350.0	350.0	350.0	350.0	350.0
	09INR0074	Motley	Wind		0.0	70.0	70.0	70.0	70.0	70.0
	10INR0041	Floyd	Wind		0.0	135.0	135.0	135.0	135.0	135.0
	10INR0081a	Clay	Wind		0.0	30.4	30.4	30.4	30.4	30.4
	10INR0039	Dickens	Wind		0.0	200.0	200.0	200.0	200.0	200.0
	11INR0029	Throckmorton	Wind		0.0	200.0	200.0	200.0	200.0	200.0
	07INR0013	Coke	Wind		0.0	200.0	200.0	200.0	200.0	200.0
	07INR0015	Foard	Wind		0.0	180.0	180.0	180.0	180.0	180.0
	10INR0008	Pecos	Wind		0.0	500.0	500.0	500.0	500.0	500.0
	07INR0026	Baylor	Wind		0.0	400.0	400.0	400.0	400.0	400.0
	07INR0035	Tom Green	Wind		0.0	270.0	270.0	270.0	270.0	270.0
	08INR0061	Hardeman	Wind		0.0	200.0	200.0	200.0	200.0	200.0
	08INR0062	Archer	Wind		0.0	249.0	249.0	249.0	249.0	249.0
	10INR0019	Deaf Smith	Wind		0.0	609.0	609.0	609.0	609.0	609.0
	10INR0033	Armstrong	Wind		0.0	399.0	399.0	399.0	399.0	399.0
	10INR0042	Mason	Wind		0.0	170.0	170.0	170.0	170.0	170.0
	09INR0076	Jackson	Wind		0.0	300.0	300.0	300.0	300.0	300.0
	10INR0056	Borden	Wind		0.0	249.0	249.0	249.0	249.0	249.0
	10INR0059	Zapata	Wind		0.0	250.7	250.7	250.7	250.7	250.7
	10INR0060	Willacy	Wind		0.0	400.5	400.5	400.5	400.5	400.5
	10INR0077	Callahan	Wind		0.0	101.0	101.0	101.0	101.0	101.0
	10INR0051	Brazoria	Wind		0.0	200.0	200.0	200.0	200.0	200.0
	09INR0041	Mitchell	Wind		0.0	300.0	300.0	300.0	300.0	300.0
	11INR0033b	Cameron	Wind		0.0	200.0	200.0	200.0	200.0	200.0
	08INR0014	Webb	Wind		0.0	183.0	183.0	183.0	183.0	183.0
	11INR0050	Crosby	Wind		0.0	149.0	149.0	149.0	149.0	149.0
	10INR0009	Castro	Wind		0.0	300.0	300.0	300.0	300.0	300.0
	09INR0075	Kinney	Wind		0.0	248.0	248.0	248.0	248.0	248.0
	11INR0062	Nueces	Wind		0.0	149.0	149.0	149.0	149.0	149.0
	10INR0062b	Pecos	Wind		0.0	49.5	49.5	49.5	49.5	49.5
	08INR0020	Eastland	Wind		0.0	200.0	200.0	200.0	200.0	200.0
	11INR0019	Upton	Wind		0.0	200.0	200.0	200.0	200.0	200.0
	11INR0057	Cameron	Wind		0.0	144.0	144.0	144.0	144.0	144.0
	11INR0008a	Roberts	Wind		0.0	0.0	1000.0	1000.0	1000.0	1000.0
	11INR0039	Starr	Wind		0.0	0.0	201.0	201.0	201.0	201.0
	11INR0047	Deaf Smith	Wind		0.0	0.0	600.0	600.0	600.0	600.0
	07INR0014a	Wilbarger	Wind		0.0	0.0	140.0	140.0	140.0	140.0
	07INR0014b	Wilbarger	Wind		0.0	0.0	70.0	70.0	70.0	70.0
	10INR0081b	Clay	Wind		0.0	0.0	19.2	19.2	19.2	19.2
	06INR0022d	Kenedy	Wind		0.0	0.0	200.0	200.0	200.0	200.0
	11INR0005	Upton	Wind		0.0	0.0	500.0	500.0	500.0	500.0
	11INR0025	Crockett	Wind		0.0	0.0	400.0	400.0	400.0	400.0
	11INR0043	Coke	Wind		0.0	0.0	300.0	300.0	300.0	300.0
	09INR0048	Jack	Wind		0.0	0.0	150.0	150.0	150.0	150.0
	12INR0021	Edwards	Wind		0.0	0.0	165.0	165.0	165.0	165.0
	10INR0062c	Pecos	Wind		0.0	0.0	201.0	201.0	201.0	201.0
	08INR0031	Childress	Wind		0.0	0.0	100.0	100.0	100.0	100.0
	12INR0002	Briscoe	Wind		0.0	0.0	750.0	750.0	750.0	750.0
	08INR0041	Coke	Wind		0.0	0.0	0.0	200.0	200.0	200.0
	08INR0019a	Gray	Wind		0.0	0.0	0.0	250.0	250.0	250.0
	08INR0019b	Gray	Wind		0.0	0.0	0.0	250.0	250.0	250.0
	08INR0019c	Gray	Wind		0.0	0.0	0.0	250.0	250.0	250.0
	08INR0044	Concho	Wind		0.0	0.0	0.0	200.0	200.0	200.0
	06INR0022f	Kenedy	Wind		0.0	0.0	0.0	200.0	200.0	200.0
	08INR0054	Comanche	Wind		0.0	0.0	0.0	401.0	401.0	401.0
	08INR0042	Coke	Wind		0.0	0.0	0.0	200.0	200.0	200.0

Unit Capacities - Summer

Units used in determining the generation resources in the Summer Summary

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Unit Name	Unit Code	County	Fuel	CM Zone	2010	2011	2012	2013	2014	2015
	09INR0025	Concho	Wind		0.0	0.0	0.0	180.0	180.0	180.0
	12INR0005	Floyd	Wind		0.0	0.0	0.0	1100.0	1100.0	1100.0
	12INR0018	Gray	Wind		0.0	0.0	0.0	600.0	600.0	600.0
	12INR0022	Hidalgo	Wind		0.0	0.0	0.0	200.0	200.0	200.0
	12INR0029	Swisher	Wind		0.0	0.0	0.0	500.0	500.0	500.0
	13INR0005	Carson	Wind		0.0	0.0	0.0	0.0	600.0	600.0
	13INR0006	Gray	Wind		0.0	0.0	0.0	0.0	750.0	750.0
	06INR0022e	Kenedy	Wind		0.0	0.0	0.0	0.0	200.0	200.0
	14INR0001	Pecos	Wind		0.0	0.0	0.0	0.0	0.0	500.0
Potential Confidential Wind Resources					**10,561.0**	**18,435.1**	**23,231.3**	**27,762.3**	**29,312.3**	**29,812.3**
Cobisa-Greenville	06INR0006	Hunt	Gas		0.0	0.0	0.0	1792.0	1792.0	1792.0
Excluded Resources					**0.0**	**0.0**	**0.0**	**1,792.0**	**1,792.0**	**1,792.0**

Changes from Last Report (May 2009 CDR)

1	The addition of 428 MW of available generation through newly signed interconnection agreements together with the seasonal re-ratings of existing units showed an increase in resources through 2014 from May 2009 report. However, the exclusion of the Cobisa-Greenville plant offsets that increase by 1,792 MW, beginning in 2013, lowering the expected reserve margin below target levels for 2014 and beyond.
2	The chart below shows the differences by summary line item by year from our last report. Positive amounts indicate an increase from the last report.

Load Forecast:	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Total Summer Peak Demand, MW						
less LAARs Serving as Responsive Reserve, MW						
less LAARs Serving as Non-Spinning Reserve, MW	No change from prior report					N/A
less BULs, MW						
less Energy Efficiency Programs (per HB3693)						
Firm Load Forecast, MW						

Resources:	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Installed Capacity, MW	3,140	3,140	3,140	3,140	3,140	
Capacity from Private Networks, MW	0	25	25	25	25	
Effective Load-Carrying Capability (ELCC) of Wind Generation, MW	68	68	68	68	68	
RMR Units to be under Contract, MW	627	0	0	0	0	
Operational Generation, MW	**3,835**	**3,233**	**3,233**	**3,233**	**3,233**	
						N/A
50% of Non-Synchronous Ties, MW	0	0	0	0	0	
Switchable Units, MW	0	0	0	0	0	
Available Mothballed Generation , MW	-297	-322	-322	-322	-322	
Planned Units (not wind) with Signed IA and Air Permit, MW	-2,440	-2,177	-2,177	-3,969	-3,969	
ELCC of Planned Wind Units with Signed IA, MW	-50	-53	-27	-47	-47	
Total Resources, MW	**1,049**	**681**	**708**	**-1,105**	**-1,105**	

less Switchable Units Unavailable to ERCOT, MW	0	0	0	0	0	
less Retiring Units, MW	0	0	0	0	0	N/A
Resources, MW	**1,049**	**681**	**708**	**-1,105**	**-1,105**	

CDR Definitions

Available Mothballed Generation
The probability that a mothballed unit will return to service, as provided by its owner, multiplied by the capacity of the unit. Return probabilities are considered protected information under the ERCOT Protocols and therefore are not included in this report.

Balancing Up Load (BUL)
Loads capable of reducing the need for electrical energy when providing Balancing Up Load Energy Service as described in the ERCOT Protocols, Section 6, Ancillary Services.

DC Tie
Any non-synchronous transmission interconnections between ERCOT and non-ERCOT electric power systems. For this report, 50% of DC Tie capacity is included in the Resources section and 50% is included in Other Potential Resources.

Effective Load-Carrying Capability (ELCC) of Wind Generation
The amount of wind generation that contributes toward the margin calculation. Currently, the value is 8.7% of the nameplate capacity.

Energy Efficiency
Improvements in the use of electricity that are achieved through facility or equipment improvements, devices, or processes that produce reductions in demand or energy consumption with the same or higher level of end-use service and that do not materially degrade existing levels of comfort, convenience, and productivity.

Interconnection Agreement (IA)
An agreement that sets forth requirements for physical connection between an Eligible Transmission Service Customer and Transmission and/or Distribution Service Providers.

Loads acting as a Resource (LaaR)
Load capable of reducing or increasing the need for electrical energy or providing Ancillary Services to the ERCOT System, as described in the ERCOT Protocols, Section 6, Ancillary Services.

Mothballed Generation Resource
A Generation Resource for which a Generation Entity has submitted a Notification of Suspension of Operations, for which ERCOT has declined to execute an RMR Agreement, and for which the Generation Entity has not announced retirement of the Generation Resource.

Net Dependable Capability
Maximum sustainable capability of a Generation Resource as demonstrated by performance testing.

Other Potential Resources
Capacity Resources that include one of the following:

- Remaining Mothballed Capacity
- DC tie capacity not included as resources in the reserve margin calculation
- Planned Units in Full Interconnection Study Phase. New wind generation is derated to the ELCC of 8.7% of nameplate capacity.

Planned Units in Full Interconnection Study Phase
Units undergoing detailed studies to determine the effects of the addition of new generation on the transmission system prior to signing an IA.

Planned Units with Signed IA
Units committed to operation via an agreement with the transmission provider. For some Resources, in order to be counted in reserve margin calculations, air permits must also be secured.

Private Use Networks
An electric network connected to the ERCOT Transmission Grid that contains load that is not directly metered by ERCOT (i.e., load that is typically netted with internal generation).

Reliability Must-Run (RMR) Unit
A Generation Resource unit operated under the terms of an Agreement with ERCOT that would not otherwise be operated except that they are necessary to provide voltage support, stability or management of localized transmission constraints under first contingency criteria.

Remaining Mothballed Capacity
The difference in the Available Mothballed Generation and the total capacity of Mothballed Generation Resources in the ERCOT Region.

Retiring Unit
A Generation Resource for which a Generation Entity has submitted a Notification of Suspension of Operations, for which ERCOT has declined to execute an RMR Agreement, and for which the Generation Entity has announced retirement of the Generation Resource.

Switchable Resouce
A Generation Resource that can be connected to either the ERCOT Transmission Grid or a grid outside the ERCOT Region.

STP Attachment 17

Nuclear Operating Company
South Texas Project Electric Generating Station P.O. Box 289 Wadsworth, Texas 77483

August 3, 2005
NOC-AE-05001919
File No.: G24.02
10CFR50
STI: 31911653

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
One White Flint North
11555 Rockville Pike
Rockville, MD 20852-2738

South Texas Project
Units 1 and 2
Docket Nos. STN 50-498 and STN 50-499
Renewal of the Wastewater Discharge Permit

Pursuant to the South Texas Project Operating License, Appendix B (Environmental Protection Plan), Section 3.2, the South Texas Project submits the attached copy of the renewed Permit to Discharge Wastes (Permit No. 01908) from the Texas Commission on Environmental Quality. There are no substantial changes to this permit. In addition, Appendix B requires that renewed permits be reported to the NRC within 30 days following approval.

There are no commitments in this letter.

If you should have any questions on this matter, please contact S. L. Dannhardt at (361) 972-8328 or me at (361) 972-7879.

RA Gangluff
R. A. Gangluff
Manager, Chemistry

MKK/

Attachment: Renewed Permit to Discharge Wastes

C001

cc:

(paper copy)

Bruce S. Mallett
Regional Administrator, Region IV
U. S. Nuclear Regulatory Commission
611 Ryan Plaza Drive, Suite 400
Arlington, Texas 76011-8064

Richard A. Ratliff
Bureau of Radiation Control
Texas Department of State Health Services
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Jeffrey Cruz
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P. O. Box 289, Mail Code: MN116
Wadsworth, TX 77483

C. M. Canady
City of Austin
Electric Utility Department
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Austin, TX 78704

(electronic copy)

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U. S. Nuclear Regulatory Commission

Jack A. Fusco
Michael A. Reed
Texas Genco, LP

C. Kirksey
City of Austin

Jon C. Wood
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R. K. Temple
E. Alarcon
City Public Service

TPDES PERMIT NO. WQ0001908000
[For TCEQ office use only -
EPA I.D. No. TX0064947]

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY
P. O. Box 13087
Austin, Texas 78711-3087

This is a renewal of TPDES Permit No. WQ0001908000, issued on November 2, 2000.

PERMIT TO DISCHARGE WASTES
under provisions of
Section 402 of the Clean Water Act
and Chapter 26 of the Texas Water Code

STP Nuclear Operating Company

whose mailing address is

P. O. Box 289
Wadsworth, Texas 77483-0289

is authorized to treat and discharge wastes from the South Texas Project Electric Generating Station (SIC 4911)

located on Farm-to-Market Road 521, approximately 10 miles north of Matagorda Bay and 12 miles south-southwest of the City of Bay City, Matagorda County, Texas

to Colorado River Tidal in Segment No. 1401 of the Colorado River Basin

only according to effluent limitations, monitoring requirements and other conditions set forth in this permit, as well as the rules of the Texas Commission on Environmental Quality (TCEQ), the laws of the State of Texas, and other orders of the TCEQ. The issuance of this permit does not grant to the permittee the right to use private or public property for conveyance of wastewater along the discharge route described in this permit. This includes, but is not limited to, property belonging to any individual, partnership, corporation or other entity. Neither does this permit authorize any invasion of personal rights nor any violation of federal, state, or local laws or regulations. It is the responsibility of the permittee to acquire property rights as may be necessary to use the discharge route.

This permit shall expire at midnight on December 1, 2009.

ISSUED DATE: JUL 21 2005

For the Commission

1. During the period beginning upon date of issuance and lasting through date of expiration, the permittee is authorized to discharge (*5) recirculated cooling water, cooling reservoir blowdown, previously monitored effluents, storm water, and makeup water from Colorado River subject to the following effluent limitations:

   The daily average flow of effluent shall not exceed 144 million gallons per day (MGD). The daily maximum flow shall not exceed 200 MGD.

Effluent Characteristics	Discharge Limitations			Minimum Self-Monitoring Requirements	
	Daily Average mg/l	Daily Maximum mg/l	Single Grab mg/l	Report Daily Average and Daily Maximum Measurement Frequency	Sample Type
Flow (MGD)	(Report)	(Report)	N/A	Continuous (*1)	Record
Colorado River Flow (MGD) (*5)	N/A	(Report)	N/A	1/day (*1)	Estimate
Temperature (°F)	(95 °F) (*2)	(97 °F) (*2)	N/A	Continuous (*1)	In-Situ
Total Residual Chlorine (*3)	N/A	0.05	N/A	1/week (*1)	Grab (*4)

(*1) When discharge occurs from Outfall 001.
(*2) See "Other Requirements," provision No. 9.
(*3) See "Other Requirements," provision No. 5.
(*4) Samples shall be representative of periods of chlorination.
(*5) See "Other Requirements," provision No. 4.

2. The pH shall not be less than 6.0 standard units nor greater than 9.0 standard units and shall be monitored 1/day, by grab sample.

3. There shall be no discharge of floating solids or visible foam in other than trace amounts and no discharge of visible oil.

4. Effluent monitoring samples shall be taken at the following location: At Outfall 001, which is at a point in the blowdown line prior to entering the Colorado River.

1. During the period beginning upon date of issuance and lasting through date of expiration, the permittee is authorized to discharge low volume waste sources (*1) commingled with previously monitored effluent (PME) from the metal cleaning waste system discharge subject to the following effluent limitations:

Volume: Flow variable.

Effluent Characteristics	Discharge Limitations			Minimum Self-Monitoring Requirements	
	Daily Average mg/l	Daily Maximum mg/l	Single Grab mg/l	Report Daily Average and Daily Maximum Measurement Frequency	Sample Type
Flow (MGD)	(Report)	(Report)	N/A	1/day	Estimate
Total Suspended Solids	30	100	100	1/week	Grab (*2)
Oil and Grease	15	20	20	1/week	Grab (*2)

(*1) See "Other Requirements," provision 10.

(*2) If more than one source is associated with this particular waste category, grab samples from each source shall be analyzed and the analytical values combined on a flow weighted basis with the calculated values used to determine the "Daily Average" for the month. The highest analytical value of all grab samples for the monthly reporting period shall be reported as the "Daily Maximum."

2. There shall be no discharge of floating solids or visible foam in other than trace amounts and no discharge of visible oil.

3. Effluent monitoring samples shall be taken at the following location: At Outfall 101, where low volume waste sources (*1) commingled with previously monitored effluents (PME) are discharged from the neutralization basins prior to mixing with any other waste stream.

1. During the period beginning upon date of issuance and lasting through date of expiration, the permittee is authorized to discharge low volume waste sources (*1) from the oily waste treatment system and storm water subject to the following effluent limitations:

Volume: Flow variable.

Effluent Characteristics	Discharge Limitations			Minimum Self-Monitoring Requirements	
	Daily Average mg/l	Daily Maximum mg/l	Single Grab mg/l	Report Daily Average and Daily Maximum Measurement Frequency	Sample Type
Flow (MGD)	(Report)	(Report)	N/A	1/day	Estimate
Total Suspended Solids	30	100	100	1/week	Grab (*2)
Oil and Grease	15	20	20	1/week	Grab (*2)

(*1) See "Other Requirements," provision 10.

(*2) If more than one source is associated with this particular waste category, grab samples from each source shall be analyzed and the analytical values combined on a flow weighted basis with the calculated values used to determine the "Daily Average" for the month. The highest analytical value of all grab samples for the monthly reporting period shall be reported as the "Daily Maximum."

2. There shall be no discharge of floating solids or visible foam in other than trace amounts and no discharge of visible oil.

3. Effluent monitoring samples shall be taken at the following location: Outfall 201, where low volume waste sources are discharged from the oily waste treatment system prior to mixing with any other waste stream.

1. During the period beginning upon date of issuance and lasting through date of expiration, the permittee is authorized to discharge treated sanitary sewage commingled with car wash water and air conditioning condensate subject to the following effluent limitations:

   Volume: Continuous and flow variable.

Effluent Characteristics	Discharge Limitations			Minimum Self-Monitoring Requirements	
	Daily Average mg/l	Daily Maximum mg/l	Single Grab mg/l	Report Daily Average and Daily Maximum Measurement Frequency	Sample Type
Flow (MGD)	(Report)	(Report)	N/A	1/day	Estimate
Biochemical Oxygen Demand (5-day)	20	45	45	1/week	Grab
Total Suspended Solids	20	45	45	1/week	Grab

2. The effluent shall contain a minimum chlorine residual of 1.0 mg/l after a detention time of at least 20 minutes (based on peak flow), and shall be monitored 1/week, by grab sample.

3. There shall be no discharge of floating solids or visible foam in other than trace amounts and no discharge of visible oil.

4. Effluent monitoring samples shall be taken at the following location: At Outfall 401, at discharge from the sewage treatment plant (West Sanitary Waste Treatment System) prior to mixing with any other waste stream.

1. During the period beginning upon date of issuance and lasting through date of expiration, the permittee is authorized to discharge metal cleaning waste (*1) subject to the following effluent limitations (*3):

Volume: Intermittent and flow variable.

Effluent Characteristics	Discharge Limitations			Minimum Self-Monitoring Requirements	
	Daily Average mg/l	Daily Maximum mg/l	Single Grab mg/l	Report Daily Average and Daily Maximum Measurement Frequency	Sample Type
Flow (MGD)	(Report)	(Report)	N/A	1/day (*2)	Estimate
Iron, Total	1.0	1.0	1.0	1week (*2)	Grab
Copper, Total	0.5	1.0	1.0	1/week (*2)	Grab

(*1) See "Other Requirements," provision No. 7.
(*2) When discharge occurs.

2. There shall be no discharge of floating solids or visible foam in other than trace amounts and no discharge of visible oil.

3. Effluent monitoring samples shall be taken at the following location: At Outfall 501, where metal cleaning wastes are discharged prior to mixing with any other waste stream.

1. During the period beginning upon date of issuance and lasting through date of expiration, the permittee is authorized to discharge treated sanitary sewage commingled with air conditioning condensate and HVAC cooling tower blowdown subject to the following effluent limitations:

Volume: Continuous and flow variable.

Effluent Characteristics	Discharge Limitations			Minimum Self-Monitoring Requirements	
	Daily Average mg/l	Daily Maximum mg/l	Single Grab mg/l	Report Daily Average and Daily Maximum Measurement Frequency	Sample Type
Flow (MGD)	(Report)	(Report)	N/A	1/day	Estimate
Biochemical Oxygen Demand (5-day)	20	45	45	1week	Grab
Total Suspended Solids	20	45	45	1/week	Grab

2. The effluent shall contain a minimum chlorine residual of 1.0 mg/l after a detention time of at least 20 minutes (based on peak flow), and shall be monitored 1/week, by grab sample.

3. There shall be no discharge of floating solids or visible foam in other than trace amounts and no discharge of visible oil.

4. Effluent monitoring samples shall be taken at the following location: At Outfall 601, at discharge from the sewage treatment plant (Training Sanitary Waste Treatment Facility) prior to mixing with any other waste stream.

DEFINITIONS AND STANDARD PERMIT CONDITIONS

As required by Title 30 Texas Administrative Code (TAC) Chapter 305, certain regulations appear as standard conditions in waste discharge permits. 30 TAC §§ 305.121 - 305.129 (relating to Permit Characteristics and Conditions) as promulgated under the Texas Water Code §§ 5.103 and 5.105, and the Texas Health and Safety Code §§ 361.017 and 361.024(a), establish the characteristics and standards for waste discharge permits, including sewage sludge, and those sections of 40 Code of Federal Regulations (CFR) Part 122 adopted by reference by the Commission. The following text includes these conditions and incorporates them into this permit. All definitions in Section 26.001 of the Texas Water Code and 30 TAC Chapter 305 shall apply to this permit and are incorporated by reference. Some specific definitions of words or phrases used in this permit are as follows:

1. Flow Measurements

   a. Annual average flow - the arithmetic average of all daily flow determinations taken within the preceding 12 consecutive calendar months. The annual average flow determination shall consist of daily flow volume determinations made by a totalizing meter, charted on a chart recorder and limited to major domestic wastewater discharge facilities with a 1 million gallons per day or greater permitted flow.

   b. Daily average flow - the arithmetic average of all determinations of the daily flow within a period of one calendar month. The daily average flow determination shall consist of determinations made on at least four separate days. If instantaneous measurements are used to determine the daily flow, the determination shall be the arithmetic average of all instantaneous measurements taken during that month. Daily average flow determination for intermittent discharges shall consist of a minimum of three flow determinations on days of discharge.

   c. Daily maximum flow - the highest total flow for any 24-hour period in a calendar month.

   d. Instantaneous flow - the measured flow during the minimum time required to interpret the flow measuring device.

   e. 2-hour peak flow (domestic wastewater treatment plants) - the maximum flow sustained for a two-hour period during the period of daily discharge. The average of multiple measurements of instantaneous maximum flow within a two-hour period may be used to calculate the 2-hour peak flow.

   f. Maximum 2-hour peak flow (domestic wastewater treatment plants) - the highest 2-hour peak flow for any 24-hour period in a calender month.

2. Concentration Measurements

   a. Daily average concentration - the arithmetic average of all effluent samples, composite or grab as required by this permit, within a period of one calendar month, consisting of at least four separate representative measurements.

      i. For domestic wastewater treatment plants - When four samples are not available in a calendar month, the arithmetic average (weighted by flow) of all values in the previous four consecutive month period consisting of at least four measurements shall be utilized as the daily average concentration.

      ii. For all other wastewater treatment plants - When four samples are not available in a calender month, the arithmetic average (weighted by flow) of all values taken during the month shall be utilized as the daily average concentration.

   b. 7-day average concentration - the arithmetic average of all effluent samples, composite or grab as required by this permit, within a period of one calendar week, Sunday through Saturday.

   c. Daily maximum concentration - the maximum concentration measured on a single day, by the sample type specified in the permit, within a period of one calender month.

   d. Daily discharge - the discharge of a pollutant measured during a calendar day or any 24-hour period that reasonably represents the calendar day for purposes of sampling. For pollutants with limitations expressed in terms of mass, the "daily discharge" is calculated as the total mass of the pollutant discharged over the sampling day. For pollutants with limitations expressed in other units of measurement, the "daily discharge" is calculated as the average measurement of the pollutant over the sampling day.

      The "daily discharge" determination of concentration made using a composite sample shall be the concentration of the composite sample. When grab samples are used, the "daily discharge" determination of concentration shall be the arithmetic average (weighted by flow value) of all samples collected during that day.

   e. Fecal coliform bacteria concentration - the number of colonies of fecal coliform bacteria per 100 milliliters effluent. The daily average fecal coliform bacteria concentration is a geometric mean of the values for the effluent samples collected in a calendar month. The geometric mean shall be determined by calculating the nth root of the product of all measurements made in a calender month, where n equals the number of measurements made; or, computed as the antilogarithm of the arithmetic mean of the logarithms of all measurements made in a calender month. For any measurement of fecal coliform bacteria equaling zero, a substituted value of one shall be made for input into either computation method. The 7-day average for fecal coliform bacteria is the geometric mean of the values for all effluent samples collected during a calender week.

f. Daily average loading (lbs/day) - the arithmetic average of all daily discharge loading calculations during a period of one calender month. These calculations must be made for each day of the month that a parameter is analyzed. The daily discharge, in terms of mass (lbs/day), is calculated as (Flow, MGD x Concentration, mg/l x 8.34).

g. Daily maximum loading (lbs/day) - the highest daily discharge, in terms of mass (lbs/day), within a period of one calender month.

3. Sample Type

a. Composite sample - For domestic wastewater, a composite sample is a sample made up of a minimum of three effluent portions collected in a continuous 24-hour period or during the period of daily discharge if less than 24 hours, and combined in volumes proportional to flow, and collected at the intervals required by 30 TAC § 319.9 (a). For industrial wastewater, a composite sample is a sample made up of a minimum of three effluent portions collected in a continuous 24-hour period or during the period of daily discharge if less than 24 hours, and combined in volumes proportional to flow, and collected at the intervals required by 30 TAC § 319.9 (b).

b. Grab sample - an individual sample collected in less than 15 minutes.

4. Treatment Facility (facility) - wastewater facilities used in the conveyance, storage, treatment, recycling, reclamation and/or disposal of domestic sewage, industrial wastes, agricultural wastes, recreational wastes, or other wastes including sludge handling or disposal facilities under the jurisdiction of the Commission.

5. The term "sewage sludge" is defined as solid, semi-solid, or liquid residue generated during the treatment of domestic sewage in 30 TAC Chapter 312. This includes the solids which have not been classified as hazardous waste separated from wastewater by unit processes .

6. Bypass - the intentional diversion of a waste stream from any portion of a treatment facility.

MONITORING AND REPORTING REQUIREMENTS

1. Self-Reporting

Monitoring results shall be provided at the intervals specified in the permit. Unless otherwise specified in this permit or otherwise ordered by the Commission, the permittee shall conduct effluent sampling and reporting in accordance with 30 TAC §§ 319.4 - 319.12. Unless otherwise specified, a monthly effluent report shall be submitted each month, to the Enforcement Division (MC 224), by the 20th day of the following month for each discharge which is described by this permit whether or not a discharge is made for that month. Monitoring results must be reported on an approved self-report form, that is signed and certified as required by Monitoring and Reporting Requirements No. 10.

As provided by state law, the permittee is subject to administrative, civil and criminal penalties, as applicable, for negligently or knowingly violating the Clean Water Act, the Texas Water Code, Chapters 26, 27, and 28, and Texas Health and Safety Code, Chapter 361, including but not limited to knowingly making any false statement, representation, or certification on any report, record, or other document submitted or required to be maintained under this permit, including monitoring reports or reports of compliance or noncompliance, or falsifying, tampering with or knowingly rendering inaccurate any monitoring device or method required by this permit or violating any other requirement imposed by state or federal regulations.

2. Test Procedures

Unless otherwise specified in this permit, test procedures for the analysis of pollutants shall comply with procedures specified in 30 TAC §§319.11 - 319.12. Measurements, tests and calculations shall be accurately accomplished in a representative manner.

3. Records of Results

a. Monitoring samples and measurements shall be taken at times and in a manner so as to be representative of the monitored activity.

b. Except for records of monitoring information required by this permit related to the permittee's sewage sludge use and disposal activities, which shall be retained for a period of at least five years (or longer as required by 40 CFR Part 503), monitoring and reporting records, including strip charts and records of calibration and maintenance, copies of all records required by this permit, records of all data used to complete the application for this permit, and the certification required by 40 CFR § 264.73(b)(9) shall be retained at the facility site, or shall be readily available for review by a TCEQ representative for a period of three years from the date of the record or sample, measurement, report, application or certification. This period shall be extended at the request of the Executive Director.

c. Records of monitoring activities shall include the following:

i. date, time and place of sample or measurement;
ii. identity of individual who collected the sample or made the measurement.
iii. date and time of analysis;
iv. identity of the individual and laboratory who performed the analysis;
v. the technique or method of analysis; and
vi. the results of the analysis or measurement and quality assurance/quality control records.

The period during which records are required to be kept shall be automatically extended to the date of the final disposition of any administrative or judicial enforcement action that maybe instituted against the permittee.

4. Additional Monitoring by Permittee

If the permittee monitors any pollutant at the location(s) designated herein more frequently than required by this permit using approved analytical methods as specified above, all results of such monitoring shall be included in the calculation and reporting of the values submitted on the approved self-report form. Increased frequency of sampling shall be indicated on the self-report form.

5. Calibration of Instruments .

All automatic flow measuring or recording devices and all totalizing meters for measuring flows shall be accurately calibrated by a trained person at plant start-up and as often thereafter as necessary to ensure accuracy, but not less often than annually unless authorized by the Executive Director for a longer period. Such person shall verify in writing that the device is operating properly and giving accurate results. Copies of the verification shall be retained at the facility site and/or shall be readily available for review by a TCEQ representative for a period of three years.

6. Compliance Schedule Reports

Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of the permit shall be submitted no later than 14 days following each schedule date to the Regional Office and the Enforcement Division (MC 224).

7. Noncompliance Notification

a. In accordance with 30 TAC § 305.125(9) any noncompliance which may endanger human health or safety, or the environment shall be reported by the permittee to the TCEQ. Report of such information shall be provided orally or by facsimile transmission (FAX) to the Regional Office within 24 hours of becoming aware of the noncompliance. A written submission of such information shall also be provided by the permittee to the Regional Office and the Enforcement Division (MC 224) within five working days of becoming aware of the noncompliance. The written submission shall contain a description of the noncompliance and its cause; the potential danger to human health or safety, or the environment; the period of noncompliance, including exact dates and times; if the noncompliance has not been corrected, the time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance, and to mitigate its adverse effects.

b. The following violations shall be reported under Monitoring and Reporting Requirement 7.a.:

i. Unauthorized discharges as defined in Permit Condition 2(g).
ii. Any unanticipated bypass which exceeds any effluent limitation in the permit.
iii. Violation of a permitted maximum daily discharge limitation for pollutants listed specifically in the Other Requirements section of an Industrial TPDES permit.

c. In addition to the above, any effluent violation which deviates from the permitted effluent limitation by more than 40% shall be reported by the permittee in writing to the Regional Office and the Enforcement Division (MC 224) within 5 working days of becoming aware of the noncompliance.

d. Any noncompliance other than that specified in this section, or any required information not submitted or submitted incorrectly, shall be reported to the Enforcement Division (MC 224) as promptly as possible. For effluent limitation violations, noncompliances shall be reported on the approved self-report form.

8. In accordance with the procedures described in 30 TAC §§ 35.301 - 35.303 (relating to Water Quality Emergency and Temporary Orders) if the permittee knows in advance of the need for a bypass, it shall submit prior notice by applying for such authorization.

9. Changes in Discharges of Toxic Substances

All existing manufacturing, commercial, mining, and silvicultural permittees shall notify the Regional Office, orally or by facsimile transmission within 24 hours, and both the Regional Office and the Enforcement Division (MC 224) in writing within five (5) working days, after becoming aware of or having reason to believe:

a. That any activity has occurred or will occur which would result in the discharge, on a routine or frequent basis, of any toxic pollutant listed at 40 CFR Part 122, Appendix D, Tables II and III (excluding Total Phenols) which is not limited in the permit, if that discharge will exceed the highest of the following "notification levels":

i. One hundred micrograms per liter (100 µg/L);
ii. Two hundred micrograms per liter (200 µg/L) for acrolein and acrylonitrile; five hundred micrograms per liter (500 µg/L) for 2,4-dinitrophenol and for 2-methyl-4,6-dinitrophenol; and one milligram per liter (1 mg/L) for antimony;
iii. Five (5) times the maximum concentration value reported for that pollutant in the permit application; or
iv. The level established by the TCEQ.

b. That any activity has occurred or will occur which would result in any discharge, on a nonroutine or infrequent basis, of a toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following "notification levels":

i. Five hundred micrograms per liter (500 µg/L);
ii. One milligram per liter (1 mg/L) for antimony;
iii. Ten (10) times the maximum concentration value reported for that pollutant in the permit application; or
iv. The level established by the TCEQ.

10. Signatories to Reports

All reports and other information requested by the Executive Director shall be signed by the person and in the manner required by 30 TAC § 305.128 (relating to Signatories to Reports).

11. All Publicly Owned Treatment Works (POTWs) must provide adequate notice to the Executive Director of the following:

a. Any new introduction of pollutants into the POTW from an indirect discharger which would be subject to section 301 or 306 of the CWA if it were directly discharging those pollutants;

b. Any substantial change in the volume or character of pollutants being introduced into that POTW by a source introducing pollutants into the POTW at the time of issuance of the permit; and

c. For the purpose of this paragraph, adequate notice shall include information on:

i. The quality and quantity of effluent introduced into the POTW; and
ii. Any anticipated impact of the change on the quantity or quality of effluent to be discharged from the POTW.

PERMIT CONDITIONS

1. General

a. When the permittee becomes aware that it failed to submit any relevant facts in a permit application, or submitted incorrect information in an application or in any report to the Executive Director, it shall promptly submit such facts or information.

b. This permit is granted on the basis of the information supplied and representations made by the permittee during action on an application, and relying upon the accuracy and completeness of that information and those representations. After notice and opportunity for a hearing, this permit may be modified, suspended, or revoked, in whole or in part, in accordance with 30 TAC Chapter 305, Subchapter D, during its term for good cause including, but not limited to, the following:

i. Violation of any terms or conditions of this permit;
ii. Obtaining this permit by misrepresentation or failure to disclose fully all relevant facts; or
iii. A change in any condition that requires either a temporary or permanent reduction or elimination of the authorized discharge.

c. The permittee shall furnish to the Executive Director, upon request and within a reasonable time, any information to determine whether cause exists for amending, revoking, suspending or terminating the permit. The permittee shall also furnish to the Executive Director, upon request, copies of records required to be kept by the permit.

2. Compliance

a. Acceptance of the permit by the person to whom it is issued constitutes acknowledgment and agreement that such person will comply with all the terms and conditions embodied in the permit, and the rules and other orders of the Commission.

b. The permittee has a duty to comply with all conditions of the permit. Failure to comply with any permit condition constitutes a violation of the permit and the Texas Water Code or the Texas Health and Safety Code, and is grounds for enforcement action, for permit amendment, revocation or suspension, or for denial of a permit renewal application or an application for a permit for another facility.

c. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit.

d. The permittee shall take all reasonable steps to minimize or prevent any discharge or sludge use or disposal or other permit violation which has a reasonable likelihood of adversely affecting human health or the environment.

e. Authorization from the Commission is required before beginning any change in the permitted facility or activity that may result in noncompliance with any permit requirements.

f. A permit may be amended, suspended and reissued, or revoked for cause in accordance with 30 TAC §§ 305.62 and 305.66 and Texas Water Code Section 7.302. The filing of a request by the permittee for a permit amendment, suspension and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

g. There shall be no unauthorized discharge of wastewater or any other waste. For the purpose of this permit, an unauthorized discharge is considered to be any discharge of wastewater into or adjacent to water in the state at any location not permitted as an outfall or otherwise defined in the Other Requirements section of this permit.

h. In accordance with 30 TAC § 305.535(a), the permittee may allow any bypass to occur from a TPDES permitted facility which does not cause permitted effluent limitations to be exceeded or an unauthorized discharge to occur, but only if the bypass is also for essential maintenance to assure efficient operation.

i. The permittee is subject to administrative, civil, and criminal penalties, as applicable, under Texas Water Code §§7.051 - 7.075 (relating to Administrative Penalties), 7.101 - 7.111 (relating to Civil Penalties), and 7.141 - 7.202 (relating to Criminal Offenses and Penalties) for violations including, but not limited to, negligently or knowingly violating the federal Clean Water Act, §§ 301, 302, 306, 307, 308, 318, or 405, or any condition or limitation implementing any sections in a permit issued under the CWA § 402, or any requirement imposed in a pretreatment program approved under the CWA §§ 402 (a)(3) or 402 (b)(8).

3. Inspections and Entry

a. Inspection and entry shall be allowed as prescribed in the Texas Water Code Chapters 26, 27, and 28, and Texas Health and Safety Code Chapter 361.

b. The members of the Commission and employees and agents of the Commission are entitled to enter any public or private property at any reasonable time for the purpose of inspecting and investigating conditions relating to the quality of water in the state or the compliance with any rule, regulation, permit or other order of the Commission. Members, employees, or agents of the Commission and Commission contractors are entitled to enter public or private property at any reasonable time to investigate or monitor or, if the responsible party is not responsive or there is an immediate danger to public health or the environment, to remove or remediate a condition related to the quality of water in the state. Members, employees, Commission contractors, or agents acting under this authority who enter private property shall observe the establishment's rules and regulations concerning safety, internal security, and fire protection, and if the property has management in residence, shall notify management or the person then in charge of his presence and shall exhibit proper credentials. If any member, employee, Commission contractor, or agent is refused the right to enter in or on public or private property under this authority, the Executive Director may invoke the remedies authorized in Texas Water Code Section 7.002. The statement above, that Commission entry shall occur in accordance with an establishment's rules and regulations concerning safety, internal security, and fire protection, is not grounds for denial or restriction of entry to any part of the facility, but merely describes the Commission's duty to observe appropriate rules and regulations during an inspection.

4. Permit Amendment and/or Renewal

a. The permittee shall give notice to the Executive Director as soon as possible of any planned physical alterations or additions to the permitted facility if such alterations or additions would require a permit amendment or result in a violation of permit requirements. Notice shall also be required under this paragraph when:

i. The alteration or addition to a permitted facility may meet one of the criteria for determining whether a facility is a new source in accordance with 30 TAC § 305.534 (relating to New Sources and New Dischargers); or

ii. The alteration or addition could significantly change the nature or increase the quantity of pollutants discharged. This notification applies to pollutants which are subject neither to effluent limitations in the permit, nor to notification requirements in Monitoring and Reporting Requirements No. 9;

iii. The alteration or addition results in a significant change in the permittee's sludge use or disposal practices, and such alteration, addition, or change may justify the application of permit conditions that are different from or absent in the existing permit, including notification of additional use or disposal sites not reported during the permit application process or not reported pursuant to an approved land application plan.

b. Prior to any facility modifications, additions, or expansions that will increase the plant capacity beyond the permitted flow, the permittee must apply for and obtain proper authorization from the Commission before commencing construction.

c. The permittee must apply for an amendment or renewal prior to expiration of the existing permit in order to continue a permitted activity after the expiration date of the permit. If an application is submitted prior to the expiration date of the permit, the existing permit shall remain in effect until the application is approved, denied, or returned. If the application is returned or denied, authorization to continue such activity shall terminate upon the effective date of the action. If an application is not submitted prior to the expiration date of the permit, the permit shall expire and authorization to continue such activity shall terminate.

d. Prior to accepting or generating wastes which are not described in the permit application or which would result in a significant change in the quantity or quality of the existing discharge, the permittee must report the proposed changes to the Commission. The permittee must apply for a permit amendment reflecting any necessary changes in permit conditions, including effluent limitations for pollutants not identified and limited by this permit.

e. In accordance with the Texas Water Code § 26.029(b), after a public hearing, notice of which shall be given to the permittee, the Commission may require the permittee, from time to time, for good cause, in accordance with applicable laws, to conform to new or additional conditions.

f. If any toxic effluent standard or prohibition (including any schedule of compliance specified in such effluent standard or prohibition) is promulgated under Section 307(a) of the Clean Water Act for a toxic pollutant which is present in the discharge and that standard or prohibition is more stringent than any limitation on the pollutant in this permit, this permit shall be modified or revoked and reissued to conform to the toxic effluent standard or prohibition. The permittee shall comply with effluent standards or prohibitions established under Section 307(a) of the Clean Water Act for toxic pollutants within the time provided in the regulations that established those standards or prohibitions, even if the permit has not yet been modified to incorporate the requirement.

5. Permit Transfer

a. Prior to any transfer of this permit, Commission approval must be obtained. The Commission shall be notified in writing of any change in control or ownership of facilities authorized by this permit. Such notification should be sent to the Water Quality Applications Team (MC 161) of the Registration, Review, and Reporting Division.

b. A permit may be transferred only according to the provisions of 30 TAC § 305.64 (relating to Transfer of Permits) and 30 TAC § 50.133 (relating to Executive Director Action on Application or WQMP update).

6. Relationship to Hazardous Waste Activities

This permit does not authorize any activity of hazardous waste storage, processing, or disposal which requires a permit or other authorization pursuant to the Texas Health and Safety Code.

7. Relationship to Water Rights

Disposal of treated effluent by any means other than discharge directly to water in the state must be specifically authorized in this permit and may require a permit pursuant to Chapter 11 of the Texas Water Code.

8. Property Rights

A permit does not convey any property rights of any sort, or any exclusive privilege.

9. Permit Enforceability

The conditions of this permit are severable, and if any provision of this permit, or the application of any provision of this permit to any circumstances, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.

10. Relationship to Permit Application

The application pursuant to which the permit has been issued is incorporated herein; provided, however, that in the event of a conflict between the provisions of this permit and the application, the provisions of the permit shall control.

11. Notice of Bankruptcy.

a. Each permittee shall notify the executive director, in writing, immediately following the filing of a voluntary or involuntary petition for bankruptcy under any chapter of Title 11 (Bankruptcy) of the United States Code (11 USC) by or against:

i. the permittee;
ii. an entity (as that term is defined in 11 USC, §101(15)) controlling the permittee or listing the permit or permittee as property of the estate; or
iii. an affiliate (as that term is defined in 11 USC, §101(2)) of the permittee.

b. This notification must indicate:

i. the name of the permittee;
ii. the permit number(s);
iii. the bankruptcy court in which the petition for bankruptcy was filed; and
iv. the date of filing of the petition.

OPERATIONAL REQUIREMENTS

1. The permittee shall at all times ensure that the facility and all of its systems of collection, treatment, and disposal are properly operated and maintained. This includes, but is not limited to, the regular, periodic examination of wastewater solids within the treatment plant by the operator in order to maintain an appropriate quantity and quality of solids inventory as described in the various operator training manuals and according to accepted industry standards for process control. Process control, maintenance, and operations records shall be retained at the facility site, or shall be readily available for review by a TCEQ representative, for a period of three years.

2. Upon request by the Executive Director, the permittee shall take appropriate samples and provide proper analysis in order to demonstrate compliance with Commission rules. Unless otherwise specified in this permit or otherwise ordered by the Commission, the permittee shall comply with all applicable provisions of 30 TAC Chapter 312 concerning sewage sludge use and disposal and 30 TAC §§ 319.21 - 319.29 concerning the discharge of certain hazardous metals.

3. Domestic wastewater treatment facilities shall comply with the following provisions:

a. The permittee shall notify the Municipal Permits Team, Wastewater Permitting Section (MC 148) of the Water Quality Division, in writing, of any facility expansion at least 90 days prior to conducting such activity.

b. The permittee shall submit a closure plan for review and approval to the Agriculture and Sludge Team, Wastewater Permitting Section (MC 148) of the Water Quality Division, for any closure activity at least 90 days prior to conducting such activity. Closure is the act of permanently taking a waste management unit or treatment facility out of service and includes the permanent removal from service of any pit, tank, pond, lagoon, surface impoundment and/or other treatment unit regulated by this permit.

4. The permittee is responsible for installing prior to plant start-up, and subsequently maintaining, adequate safeguards to prevent the discharge of untreated or inadequately treated wastes during electrical power failures by means of alternate power sources, standby generators, and/or retention of inadequately treated wastewater.

5. Unless otherwise specified, the permittee shall provide a readily accessible sampling point and, where applicable, an effluent flow measuring device or other acceptable means by which effluent flow may be determined.

6. The permittee shall remit an annual water quality fee to the Commission as required by 30 TAC Chapter 21. Failure to pay the fee may result in revocation of this permit under Texas Water Code § 7.302(b)(6).

7. Documentation

For all written notifications to the Commission required of the permittee by this permit, the permittee shall keep and make available a copy of each such notification under the same conditions as self-monitoring data are required to be kept and made available. Except for information required for TPDES permit applications, effluent data, including effluent data in permits; draft permits and permit applications, and other information specified as not confidential in 30 TAC § 1.5(d), any information submitted pursuant to this permit may be claimed as confidential by the submitter. Any such claim must be asserted in the manner prescribed in the application form or by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, information may be made available to the public without further notice. If the Commission or Executive Director agrees with the designation of confidentiality, the TCEQ will not provide the information for public inspection unless required by the Texas Attorney General or a court pursuant to an open records request. If the Executive Director does not agree with the designation of confidentiality, the person submitting the information will be notified.

8. Facilities which generate domestic wastewater shall comply with the following provisions; domestic wastewater treatment facilities at permitted industrial sites are excluded.

   a. Whenever flow measurements for any domestic sewage treatment facility reach 75 percent of the permitted daily average or annual average flow for three consecutive months, the permittee must initiate engineering and financial planning for expansion and/or upgrading of the domestic wastewater treatment and/or collection facilities. Whenever the flow reaches 90 percent of the permitted daily average or annual average flow for three consecutive months, the permittee shall obtain necessary authorization from the Commission to commence construction of the necessary additional treatment and/or collection facilities. In the case of a domestic wastewater treatment facility which reaches 75 percent of the permitted daily average or annual average flow for three consecutive months, and the planned population to be served or the quantity of waste produced is not expected to exceed the design limitations of the treatment facility, the permittee shall submit an engineering report supporting this claim to the Executive Director of the Commission.

      If in the judgement of the Executive Director the population to be served will not cause permit noncompliance, then the requirement of this section may be waived. To be effective, any waiver must be in writing and signed by the Director of the Enforcement Division (MC 149) of the Commission, and such waiver of these requirements will be reviewed upon expiration of the existing permit; however, any such waiver shall not be interpreted as condoning or excusing any violation of any permit parameter.

   b. The plans and specifications for domestic sewage collection and treatment works associated with any domestic permit must be approved by the Commission, and failure to secure approval before commencing construction of such works or making a discharge is a violation of this permit and each day is an additional violation until approval has been secured.

   c. Permits for domestic wastewater treatment plants are granted subject to the policy of the Commission to encourage the development of area-wide waste collection, treatment and disposal systems. The Commission reserves the right to amend any domestic wastewater permit in accordance with applicable procedural requirements to require the system covered by this permit to be integrated into an area-wide system, should such be developed; to require the delivery of the wastes authorized to be collected in, treated by or discharged from said system, to such area-wide system; or to amend this permit in any other particular to effectuate the Commission's policy. Such amendments may be made when the changes required are advisable for water quality control purposes and are feasible on the basis of waste treatment technology, engineering, financial, and related considerations existing at the time the changes are required, exclusive of the loss of investment in or revenues from any then existing or proposed waste collection, treatment or disposal system.

9. Domestic wastewater treatment plants shall be operated and maintained by sewage plant operators holding a valid certificate of competency at the required level as defined in 30 TAC Chapter 30.

10. For Publicly Owned Treatment Works (POTWs), the 30-day average (or monthly average) percent removal for BOD and TSS shall not be less than 85 percent, unless otherwise authorized by this permit.

11. Facilities which generate industrial solid waste as defined in 30 TAC § 335.1 shall comply with these provisions:

    a. Any solid waste, as defined in 30 TAC § 335.1 (including but not limited to such wastes as garbage, refuse, sludge from a waste treatment, water supply treatment plant or air pollution control facility, discarded materials, discarded materials to be recycled, whether the waste is solid, liquid, or semisolid), generated by the permittee during the management and treatment of wastewater, must be managed in accordance with all applicable provisions of 30 TAC Chapter 335, relating to Industrial Solid Waste Management.

    b. Industrial wastewater that is being collected, accumulated, stored, or processed before discharge through any final discharge outfall, specified by this permit, is considered to be industrial solid waste until the wastewater passes through the actual point source discharge and must be managed in accordance with all applicable provisions of 30 TAC Chapter 335.

    c. The permittee shall provide written notification, pursuant to the requirements of 30 TAC § 335.8(b)(1), to the Corrective Action Section (MC 127) of the Remediation Division informing the Commission of any closure activity involving an Industrial Solid Waste Management Unit, at least 90 days prior to conducting such an activity.

d. Construction of any industrial solid waste management unit requires the prior written notification of the proposed activity to the Registration and Reporting Section (MC 129) of the Registration, Review, and Reporting Division. No person shall dispose of industrial solid waste, including sludge or other solids from wastewater treatment processes, prior to fulfilling the deed recordation requirements of 30 TAC § 335.5.

e. The term "industrial solid waste management unit" means a landfill, surface impoundment, waste-pile, industrial furnace, incinerator, cement kiln, injection well, container, drum, salt dome waste containment cavern, or any other structure vessel, appurtenance, or other improvement on land used to manage industrial solid waste.

f. The permittee shall keep management records for all sludge (or other waste) removed from any wastewater treatment process. These records shall fulfill all applicable requirements of 30 TAC Chapter 335 and must include the following, as it pertains to wastewater treatment and discharge:

i. Volume of waste and date(s) generated from treatment process;
ii. Volume of waste disposed of on-site or shipped off-site;
iii. Date(s) of disposal;
iv. Identity of hauler or transporter;
v. Location of disposal site; and
vi. Method of final disposal.

The above records shall be maintained on a monthly basis. The records shall be retained at the facility site, or shall be readily available for review by authorized representatives of the TCEQ for at least five years.

12. For industrial facilities to which the requirements of 30 TAC Chapter 335 do not apply, sludge and solid wastes, including tank cleaning and contaminated solids for disposal, shall be disposed of in accordance with Chapter 361 of the Texas Health and Safety Code.

TCEQ Revision 05/2004

OTHER REQUIREMENTS

1. The Executive Director has reviewed this action for consistency with the goals and policies of the Texas Coastal Management Program (CMP) in accordance with the regulations of the Coastal Coordination Council (CCC) and has determined that the action is consistent with the applicable CMP goals and policies.

2. Violations of daily maximum limitations for the following pollutants shall be reported orally or by facsimile to TCEQ Region 12, within 24 hours from the time the permittee becomes aware of the violation followed by a written report within five working days to TCEQ Region 12 Office and the Enforcement Division (MC 224):

POLLUTANT	MAL (mg/l)
Copper, Total	0.010
Iron, Total	------

Test methods utilized shall be sensitive enough to demonstrate compliance with the permit effluent limitations. Permit compliance/noncompliance determinations will be based on the effluent limitations contained in this permit with consideration given to the MAL for the parameters specified above.

When an analysis of an effluent sample for any of the parameters listed above indicates no detectable levels above the MAL and the test method detection level is as sensitive as the specified MAL, a value of zero (0) shall be used for that measurement when determining calculations and reporting requirements for the self-reporting form. This applies to determinations of daily maximum concentration, calculations of loading and daily averages, and other reportable results.

When a reported value is zero (0) based on this MAL provision, the permittee shall submit the following statement with the self-reporting form either as a separate attachment to the form or as a statement in the comments section of the form.

"The reported value(s) of zero (0) for ____[list parameter(s)]____ on the self-reporting form for the term of this permit is based on the following conditions: 1) the analytical method used had a method detection level as sensitive as the MAL specified in the permit, and 2) the analytical results contained no detectable levels above the specified MAL."

When an analysis of an effluent sample for a parameter indicates no detectable levels and the test method detection level is not as sensitive as the MAL specified in the permit, or an MAL is not specified in the permit for that parameter, the level of detection achieved shall be used for that measurement when determining calculations and reporting requirements for the self-reporting form. A zero (0) may not be used.

3. The discharges from sources such as reservoir relief wells, reservoir spillway gate leakage, condenser box drainage, ground water monitoring wells, and process monitoring instrumentation are authorized. These sources may discharge to the Colorado River, to the West Branch of the Colorado River, to Little Robbins Slough and the East Fork of Little Robbins Slough.

4. For Outfall 001, the discharge from the cooling pond shall not exceed 12.5% of the flow of the Colorado River at the discharge point and there shall be no discharge from Outfall 001 when the receiving water flow adjacent to the plant is less than 800 cubic feet per second.

5. Total Residual Chlorine:

The term "total residual chlorine" (or total residual oxidants for intake water with bromides) means the value obtained using the amperometric method for total residual chlorine described in 40 CFR Part 136. The permittee may use the DPD spectrophotometric method (EPA Method 330.5) upon written notification of the Executive Director, provided that EPA has modified the existing effluent limitation guidelines (40 CFR Part 423) or has provided the permittee with demonstration that this new method is appropriate for use by steam electric power generating facilities.

Total residual chlorine may not be discharged from any single generating unit for more than two hours per day unless the discharger demonstrates to the permitting authority that discharge for more than two hours is required for macroinvertebrate control.

Simultaneous multi-unit chlorination is permitted.

6. There shall be no discharge of polychlorinated biphenyl transformer fluid.

7. The term "metal cleaning waste" means any wastewater resulting from cleaning (with or without chemical compounds) any metal process equipment including, but not limited to, boiler tube cleaning, boiler fireside cleaning, and air preheater cleaning.

8. The term "chemical metal cleaning waste" means any wastewater resulting from the cleaning of any metal process equipment with chemical compounds, including, but not limited to, boiler tube cleaning.

9. For the purposes of this permit, daily temperature discharge is defined as the flow weighted average temperature (FWAT) and shall be computed and recorded on a daily basis. FWAT shall be computed at equal time intervals not greater than two hours. The method of calculating FWAT is as follows:

$$\frac{\sum(\text{INSTANTANEOUS FLOW X INSTANTANEOUS TEMPERATURE})}{\sum(\text{INSTANTANEOUS FLOW})}$$

"Daily average temperature" shall be the arithmetic average of all FWAT's calculated during the calender month. "Daily maximum temperature" shall be the highest FWAT calculated during the calender month.

10. The term "low volume waste sources" means, taken collectively as if from one source, wastewaters from all sources except those for which specific limitations are otherwise established. Low volume waste sources include but are not limited to: wet scrubber air pollution control systems, ion exchange wate treatment systems, water treatment evaporator blowdown, laboratory and sampling streams, boiler blowdown, floor drains, cooling tower basin cleaning wastes and blowdown from recirculating house service water systems. Sanitary and air conditioning wastes are not included.

11. This provision supersedes and replaces Provision 1, Paragraph 1 of Monitoring and Reporting Requirements found on Page 4 of this permit.

    Monitoring results shall be provided at the intervals specified in the permit. Unless otherwise specified in this permit or otherwise ordered by the Commission, the permittee shall conduct effluent sampling and reporting in accordance with 30 TAC §§319.4 - 319.12. Unless otherwise specified, a monthly effluent report shall be submitted each month, to the location(s) specified on the reporting form or the instruction sheet, by the 25th day of the following month for each discharge which is described by this permit whether or not a discharge is made for that month. Monitoring results must be reported on the approved TPDES self-reporting form, Discharge Monitoring Report (DMR) Form EPA No. 3320-1, signed and certified as required by Monitoring and Reporting Requirements No. 10.

12. The mixing zone is defined as a volume within a radius of 60 feet extending over the receiving waters from the point where discharge from each jet port enters the Colorado River.. Chronic toxic criteria apply at the edge of the mixing zone.

13. Daily average concentration shall mean the arithmetic average (weighted by flow) of all effluent samples, composition or grab as required by this permit within a period of one calender month, consisting of at least four separate representative measurements. When four samples are not available in a calender month, the arithmetic average (weighted by flow) of the four most recent measurements or arithmetic average (weighted by flow) of all values taken during the month shall be utilized as the daily average concentration.

    The provision supersedes and replaces Provision 2(a), Daily Average Concentration, as defined on page 3 of this permit.

14. The permittee shall comply with the Cooling Water Intake regulations found in Title 40 Code of Federal Regulations Part 125, Subpart J. These regulations include, but are not limited to the following provisions:

    a. the permittee shall submit four copies of the Proposal for Information Collection to the Industrial Team (MC-148) of the Water Quality Division prior to the start of information collection activities, and

    b. the permittee shall submit four copies of the completed Comprehensive Demonstration Study (if required by 40 CFR Part 125, Subpart J) to the Industrial Team (MC-148) of the Water Quality Division no later than January 7, 2008.

The permittee shall meet all other applicable requirements of this regulation.

15. Wastewater discharged via Outfall 001 shall be sampled and analyzed for those parameters listed on Attachment 1 (Tables 1, 2, and 3) of this permit for a minimum of four (4) separate sampling events which are a minimum of one (1) week apart. Attachment 1 (Tables 1, 2 and 3) shall be completed with the analytical results for each outfall and sent to the TCEQ, Wastewater Permiting Section (MC-148), Industrial Team. Analytical testing for Outfall 001 shall be conducted with first available discharge events following permit issuance. Based on a technical review of the submitted analytical results, an amendment may be initiated by TCEQ staff to include additional effluent limitations and/or monitoring requirements.

ATTACHMENT 1

TABLE 1:

Outfall No.: ☐C ☐G	Effluent Concentration (mg/l)					
Pollutants	Samp. 1	Samp. 2	Samp. 3	Samp. 4	Average	
BOD (5-day)						
CBOD (5-day)						
Chemical Oxygen Demand						
Total Organic Carbon						
Ammonia Nitrogen						
Total Suspended Solids						
Nitrate Nitrogen						
Total Organic Nitrogen						
Total Phosphorus						
Oil and Grease						
Total Residual Chlorine						
Total Dissolved Solids						
Sulfate						
Chloride						
Fluoride						
Fecal Coliform						
Temperature (°F)						
pH (Standard Units; min/max)						
	Effluent Concentration (µg/l)					MAL (µg/l)
Total Aluminum						30
Total Antimony						30
Total Arsenic						10
Total Barium						10
Total Beryllium						5
Total Cadmium						1
Total Chromium						10
Trivalent Chromium						N/A
Hexavalent Chromium						10
Total Copper						10
Cyanide						20
Total Lead						5
Total Mercury						0.2
Total Nickel						10
Total Selenium						10
Total Silver						2.0
Total Thallium						10
Total Zinc						5

ATTACHMENT 1

TABLE 2:

Outfall No.: ☐C ☐G	Effluent Concentration (μg/l) (*1)					
Pollutants	Samp. 1	Samp. 2	Samp. 3	Samp. 4	Average	MAL
Benzene						10
Benzidine						50
Benzo(a)anthracene						10
Benzo(a)pyrene						10
Carbon Tetrachloride						10
Chlorobenzene						10
Chloroform						10
Chrysene						10
Cresols						(*2)
Dibromochloromethane						10
1,2-Dibromoethane						2
1,4-Dichlorobenzene						10
1,2-Dichloroethane						10
1,1-Dichloroethylene						10
Fluoride						500
Hexachlorobenzene						10
Hexachlorobutadiene						10
Hexachloroethane						20
Methyl Ethyl Ketone						50
Nitrobenzene						10
n-Nitrosodiethylamine						20
n-Nitroso-di-n-Butylamine						20
PCB's, Total (*3)						1
Pentachlorobenzene						20
Pentachlorophenol						50
Phenanthrene						10
Pyridine						20
1,2,4,5-Tetrachlorobenzene						20
Tetrachloroethylene						10
Trichloroethylene						10
1,1,1-Trichloroethane						10
2,4,5-Trichlorophenol						50
TTHM (Total Trihalomethanes)						10
Vinyl Chloride						10

(*1) Indicate units if different from μg/l.
(*2) MAL's for Cresols: p-Chloro-m-Cresol 10 μg/l; 4,6-Dinitro-o-Cresol 50 μg/l; p-Cresol 10 μg/l
(*3) Total of PCB-1242, PCB-1254, PCB-1221, PCB-1232, PCB-1248, PCB-1260, PCB-1016.

ATTACHMENT 1

TABLE 3:

Outfall No.: ☐C ☐G	Believed Present	Believed Absent	Effluent Concentration (mg/l)		
Pollutants			**Average**	**Maximum**	**No. of Samples**
Bromide					
Color (PCU)					
Nitrate-Nitrite(as N)					
Sulfide(as S)					
Sulfite(as SO_3)					
Surfactants					
Total Antimony					
Total Beryllium					
Total Boron					
Total Cobalt					
Total Iron					
Total Magnesium					
Total Molybdenum					
Total Manganese					
Total Thallium					
Total Tin					
Total Titanium					

CHRONIC BIOMONITORING REQUIREMENTS: MARINE

The provisions of this Section apply to Outfall 001 for whole effluent toxicity testing (biomonitoring).

1. Scope, Frequency and Methodology

a. The permittee shall test the effluent for toxicity in accordance with the provisions below. Such testing will determine if an appropriately dilute effluent sample adversely affects the survival, reproduction, or growth of the test organisms.

b. The permittee shall conduct all toxicity tests utilizing the test organisms, procedures, and quality assurance requirements specified below and in accordance with "Short-Term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Marine and Estuarine Organisms, Third Edition" (EPA-821-R-02-014), or the most recent update thereof:

1) Chronic static renewal 7-day survival and growth test using the mysid shrimp *(Mysidopsis bahia)* (Method 1007.0 or the most recent update thereof). A minimum of eight replicates with five organisms per replicate shall be used in the control and in each dilution. This test shall be conducted once per quarter.

2) Chronic static renewal 7-day larval survival and growth test using the inland silverside (*Menidia beryllina*) (Method 1006.0 or the most recent update thereof). A minimum of five replicates with eight organisms per replicate shall be used in the control and in each dilution. This test shall be conducted once per quarter.

The permittee must perform and report a valid test for each test species during the prescribed reporting period. An invalid test must be repeated during the same reporting period. An invalid test is herein defined as any test failing to satisfy the test acceptability criteria, including Percent Minimum Significant Difference (PMSD) boundary requirements, procedures, and quality assurance requirements specified in the test methods and permit. All test results, valid or invalid, must be submitted as described below.

c. The permittee shall use five effluent dilution concentrations and a control in each toxicity test. These additional effluent concentrations are 5%, 7%, 10%, 13%, and 17% effluent. The critical dilution, defined as 13% effluent, is the effluent concentration representative of the proportion of effluent in the receiving water during critical low flow or critical mixing conditions.

d. This permit may be amended to require a Whole Effluent Toxicity (WET) limit, Chemical-Specific (CS) limits, a Best Management Practice (BMP), additional toxicity testing, and/or other appropriate actions to address toxicity. The permittee may be required to conduct additional biomonitoring tests and/or a Toxicity Reduction Evaluation (TRE) if biomonitoring data indicate multiple numbers of unconfirmed toxicity events.

e. Testing Frequency Reduction

1) If none of the first four consecutive quarterly tests demonstrates significant lethal or sub-lethal effects, the permittee may submit this information in writing and, upon approval from the Water Quality Standards Team, reduce the testing frequency to once per six months for the invertebrate test species and once per year for the vertebrate test species.

2) If one or more of the first four consecutive quarterly tests demonstrates significant sub-lethal effects, the permittee shall continue quarterly testing for that species until four consecutive quarterly tests demonstrate no significant sub-lethal effects. At that time, the permittee may apply for the appropriate testing frequency reduction for that species.

3) If one or more of the first four consecutive quarterly tests demonstrates significant lethal effects, the permittee shall continue quarterly testing for that species until the permit is reissued. If a testing frequency reduction had been previously granted and a subsequent test demonstrates significant lethal effects, the permittee will resume a quarterly testing frequency for that species until the permit is reissued.

2. Required Toxicity Testing Conditions

a. Test Acceptance - The permittee shall repeat any toxicity test, including the control and all effluent dilutions, which fails to meet any of the following criteria:

1) a control mean survival of 80% or greater;

2) a control mean dry weight of surviving mysid shrimp of 0.20 mg or greater;

3) a control mean dry weight for surviving unpreserved inland silverside of 0.50 mg or greater and 0.43 mg or greater for surviving preserved inland silverside.

4) a control Coefficient of Variation percent (CV%) between replicates of 40 or less in the in the growth and survival tests.

5) a critical dilution CV% of 40 or less in the growth and survival endpoints for either growth and survival test. However, if statistically significant lethal or nonlethal effects are exhibited at the critical dilution, a CV% greater than 40 shall not invalidate the test.

6) a PMSD range of 11 - 37 for mysid shrimp growth;

7) a PMSD range of 11 - 28 for inland silverside growth.

b. Statistical Interpretation

1) For the mysid shrimp and the inland silverside larval survival and growth tests, the statistical analyses used to determine if there is a significant difference between the control and an effluent dilution shall be in accordance with the methods described in the "Short-Term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Marine and Estuarine Organisms, Third Edition" (EPA-821-R-02-014), or the most recent update thereof.

2) The permittee is responsible for reviewing test concentration-response relationships to ensure that calculated test-results are interpreted and reported correctly. The EPA manual, "Method Guidance and Recommendation for Whole Effluent Toxicity (WET) Testing (40 CFR Part 136)" (EPA 821-B-00-004) provides guidance on determining the validity of test results.

3) If significant lethality is demonstrated (that is, there is a statistically significant difference in survival at the critical dilution when compared to the control), the conditions of test acceptability are met, and the survival of the test organisms are equal to or greater than 80% in the critical dilution and all dilutions below that, then the permittee shall report a survival No Observed Effect Concentration (NOEC) of not less than the critical dilution for the reporting requirements.

4) The NOEC is defined as the greatest effluent dilution at which no significant effect is demonstrated. The Lowest Observed Effect Concentration (LOEC) is defined as the lowest effluent dilution at which a significant effect is demonstrated. A significant effect is herein defined as a statistically significant difference at the 95% confidence level between the survival, reproduction, or growth of the test organism(s) in a specified effluent dilution compared to the survival, reproduction, or growth of the test organism(s) in the control (0% effluent).

5) The use of NOECs and LOECs assumes either a monotonic (continuous) concentration-response relationship or a threshold model of the concentration-response relationship. For any test result that demonstrates a non-monotonic (non-continuous) response, the NOEC should be determined based on the guidance manual referenced in Item 3 above and a full report will be submitted to the Water Quality Standards Team

6) Pursuant to the responsibility assigned to the permittee in Part 2.b.2), test results that demonstrate a non-monotonic (non-continuous) concentration-response relationship may be submitted, prior to the due date, for technical review. The above-referenced guidance manual will be used when making a determination of test acceptability

7) The Water Quality Standards Team will review test results (i.e., Table 1 and Table 2 forms) for consistency with established TCEQ rules, procedures, and permit requirements.

c. Dilution Water

1) Dilution water used in the toxicity tests shall be the receiving water collected as close as possible to the discharge point, but unaffected by the discharge.

2) Where the receiving water proves unsatisfactory as a result of pre-existing instream toxicity (i.e. fails to fulfill the test acceptance criteria of item 2.a.), the permittee may substitute synthetic dilution water for the receiving water in all subsequent tests provided the unacceptable receiving water test met the following stipulations:

a) a synthetic lab water control was performed (in addition to the receiving water control) which fulfilled the test acceptance requirements of item 2.a;

b) the test indicating receiving water toxicity was carried out to completion (i.e., 7 days);

c) the permittee submitted all test results indicating receiving water toxicity with the reports and information required in Part 3.

Upon approval, the permittee may substitute other appropriate dilution water with chemical and physical characteristics similar to that of the receiving water.

d. Samples and Composites

1) The permittee shall collect a minimum of three flow-weighted 24-hour composite samples from Outfall 001. The second and third 24-hour composite samples will be used for the renewal of the dilution concentrations for each toxicity test. A 24-hour composite sample consists of a minimum of 12 effluent portions collected at equal time intervals representative of a 24-hour operating day and combined proportionally to flow, or a sample continuously collected proportionally to flow over a 24-hour operating day.

2) The permittee shall collect the 24-hour composite samples such that the samples are representative of any periodic episode of chlorination, biocide usage, or other potentially toxic substance discharged on an intermittent basis.

3) The permittee shall initiate the toxicity tests within 36 hours after collection of the last portion of the first 24-hour composite sample. The holding time for any subsequent 24-hour composite sample shall not exceed 72 hours. Samples shall be maintained at a temperature of 0-6 degrees Centigrade during collection, shipping, and storage.

4) If flow from the outfall being tested ceases during the collection of effluent samples, the requirements for the minimum number of effluent samples, the minimum number of effluent portions, and the sample holding time, are waived during that sampling period. However, the permittee must have collected an effluent composite sample volume sufficient to complete the required toxicity tests with daily renewal of the effluent. When possible, the effluent samples used for the toxicity tests shall be collected on separate days if the discharge occurs over multiple days. The effluent composite sample collection duration and the static renewal protocol associated with the abbreviated sample collection must be documented in the full report required in Part 3 of this Section.

3. <u>Reporting</u>

All reports, tables, plans, summaries, and related correspondence required in any Part of this Section shall be submitted to the attention of the Water Quality Standards Team (MC 150) of the Water Quality Division. All DMRs, including DMRs with biomonitoring data, should be sent to the Water Quality Compliance Monitoring Team of the Enforcement Division (MC 224).

a. The permittee shall prepare a full report of the results of all tests conducted pursuant to this permit in accordance with the Report Preparation Section of "Short-Term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Marine and Estuarine Organisms, Third Edition" (EPA-

821-R-02-014), or the most recent update thereof, for every valid and invalid toxicity test initiated whether carried to completion or not. All full reports shall be retained for 3 years at the plant site and shall be available for inspection by TCEQ personnel.

b. A full report must be submitted with the first valid biomonitoring test results for each test species and with the first test results any time the permittee subsequently employs a different test laboratory. Full reports need not be submitted for subsequent testing unless specifically requested. The permittee shall routinely report the results of each biomonitoring test on the Table 1 forms provided with this permit. All Table 1 reports must include the information specified in the Table 1 form attached to this permit.

   1) Annual biomonitoring test results are due on or before January 20th for biomonitoring conducted during the previous 12 month period.

   2) Semiannual biomonitoring test results are due on or before July 20th and January 20th for biomonitoring conducted during the previous 6 month period.

   3) Quarterly biomonitoring test results are due on or before April 20th, July 20th, October 20th, and January 20th, for biomonitoring conducted during the previous calendar quarter.

   4) Monthly biomonitoring test results are due on or before the 20th day of the month following sampling.

c. Enter the following codes on the DMR for the appropriate parameters for valid tests only:

   1) For the mysid shrimp, Parameter TLP3E, enter a "1" if the NOEC for survival is less than the critical dilution; otherwise, enter a "0."

   2) For the mysid shrimp, Parameter TOP3E, report the NOEC for survival.

   3) For the mysid shrimp, Parameter TXP3E, report the LOEC for survival.

   4) For the mysid shrimp, Parameter TWP3E, enter a "1" if the NOEC for growth is less than the critical dilution; otherwise, enter a "0."

   5) For the mysid shrimp, Parameter TPP3E, report the NOEC for growth.

   6) For the mysid shrimp, Parameter TYP3E, report the LOEC for growth.

   7) For the inland silverside, Parameter TLP6B, enter a "1" if the NOEC for survival is less than the critical dilution; otherwise, enter a "0."

   8) For the inland silverside, Parameter TOP6B, report the NOEC for survival.

   9) For the inland silverside, Parameter TXP6B, report the LOEC for survival.

   10) For the inland silverside, Parameter TWP6B, enter a "1" if the NOEC for growth is less than the critical dilution; otherwise, enter a "0."

   11) For the inland silverside, Parameter TPP6B, report the NOEC for growth.

   12) For the inland silverside, Parameter TYP6B, report the LOEC for growth

d. Enter the following codes on the DMR for retests only:

   1) For retest number 1, Parameter 22415, enter a "1" if the NOEC for survival is less than the critical dilution; otherwise, enter a "0."

   2) For retest number 2, Parameter 22416, enter a "1" if the NOEC for survival is less than the critical dilution; otherwise, enter a "0."

4. Persistent Toxicity

The requirements of this Part apply only when a test demonstrates a significant effect at the critical dilution. A significant effect is defined as a statistically significant difference, at the 95% confidence level, between a specified endpoint (survival, growth, or reproduction) of the test organism in a specified effluent dilution when compared to the specified endpoint of the test organism in the control. Significant lethality is defined as a statistically significant difference in survival at the critical dilution when compared to the survival of the test organism in the control. Significant sublethality is defined as a statistically significant difference in growth/reproduction at the critical dilution when compared to the growth/reproduction of the test organism in the control.

a. The permittee shall conduct a total of 2 additional tests (retests) for any species that demonstrates a significant effect (lethal or sublethal) at the critical dilution. The two retests shall be conducted monthly during the next two consecutive months. The permittee shall not substitute either of the two retests in lieu of routine toxicity testing. All reports shall be submitted within 20 days of test completion. Test completion is defined as the last day of the test. The retests shall also be reported on the DMRs as specified in Part 3.d.

b. If the retests are performed due to a demonstration of significant lethality, and one or both of the two retests specified in item 4.a. demonstrates significant lethality, the permittee shall initiate the TRE requirements as specified in Part 5. The provisions of item 4.a. are suspended upon completion of the two retests and submittal of the TRE Action Plan and Schedule defined in Part 5.

If neither test demonstrates significant lethality and the permittee is testing under the reduced testing frequency provision of Part 1.e., the permittee shall return to a quarterly testing frequency for that species.

c. If the two retests are performed due to a demonstration of significant sublethality, and one or both of the two retests specified in item 4.a. demonstrates significant lethality, the permittee shall again perform two retests as stipulated in item 4.a.

d. If the two retests are performed due to a demonstration of significant sublethality, and both retests pass, the permittee shall continue testing at the quarterly frequency until such time that the permittee can invoke the reduced testing frequency provision specified in Part 1.e.

e. Regardless of whether retesting for lethal or sublethal effects, or a combination of the two, no more than one retest per month is required for a species.

5. Toxicity Reduction Evaluation

a. Within 45 days of the last test day of the retest that demonstrates significant lethality, the permittee shall submit a General Outline for initiating a TRE. The outline shall include, but not be limited to, a description of project personnel, a schedule for obtaining consultants (if needed), a discussion of influent and/or effluent data available for review, a sampling and analytical schedule, and a proposed TRE initiation date.

b. Within 90 days of the last test day of the retest that demonstrates significant lethality, the permittee shall submit a TRE Action Plan and Schedule for conducting a TRE. The plan shall specify the approach and methodology to be used in performing the TRE. A Toxicity Reduction Evaluation is a step-wise investigation combining toxicity testing with physical and chemical analysis to determine actions necessary to eliminate or reduce effluent toxicity to a level not effecting significant lethality at the critical dilution. The TRE Action Plan shall lead to the successful elimination of significant lethal effects at the critical dilution for both test species defined in item 1.b. As a minimum, the TRE Action Plan shall include the following:

1) Specific Activities - The TRE Action Plan shall specify the approach the permittee intends to utilize in conducting the TRE, including toxicity characterizations, identifications, confirmations, source evaluations, treatability studies, and/or alternative approaches. When conducting characterization analyses, the permittee shall perform multiple characterizations and follow the procedures specified in the document entitled, "Toxicity Identification Evaluation: Characterization of Chronically Toxic Effluent, Phase I" (EPA/600/6-91/005F), or alternate procedures. The permittee shall perform multiple identifications and follow the methods

specified in the documents entitled, "Methods for Aquatic Toxicity Identification Evaluations, Phase II Toxicity Identification Procedures for Samples Exhibiting Acute and Chronic Toxicity" (EPA/600/R-92/080) and "Methods for Aquatic Toxicity Identification Evaluations, Phase III Toxicity Confirmation Procedures for Samples Exhibiting Acute and Chronic Toxicity" (EPA/600/R-92/081). All characterization, identification, and confirmation tests shall be conducted in an orderly and logical progression;

2) Sampling Plan - The TRE Action Plan should describe sampling locations, methods, holding times, chain of custody, and preservation techniques. The effluent sample volume collected for all tests shall be adequate to perform the toxicity characterization/ identification/ confirmation procedures, and chemical-specific analyses when the toxicity tests show significant lethality.

   Where the permittee has identified or suspects specific pollutant(s) and/or source(s) of effluent toxicity, the permittee shall conduct, concurrent with toxicity testing, chemical-specific analyses for the identified and/or suspected pollutant(s) and/or source(s) of effluent toxicity;

3) Quality Assurance Plan - The TRE Action Plan should address record keeping and data evaluation, calibration and standardization, baseline tests, system blanks, controls, duplicates, spikes, toxicity persistence in the samples, randomization, reference toxicant control charts, as well as mechanisms to detect artifactual toxicity; and

4) Project Organization - The TRE Action Plan should describe the project staff, project manager, consulting engineering services (where applicable), consulting analytical and toxicological services, etc.

c. Within 30 days of submittal of the TRE Action Plan and Schedule, the permittee shall implement the TRE with due diligence.

d. The permittee shall submit quarterly TRE Activities Reports concerning the progress of the TRE. The quarterly reports are due on or before April 20th, July 20th, October 20th, and January 20th. The report shall detail information regarding the TRE activities including:

1) results and interpretation of any chemical-specific analyses for the identified and/or suspected pollutant(s) performed during the quarter;

2) results and interpretation of any characterization, identification, and confirmation tests performed during the quarter;

3) any data and/or substantiating documentation which identifies the pollutant(s) and/or source(s) of effluent toxicity;

4) results of any studies/evaluations concerning the treatability of the facility's effluent toxicity;

5) any data which identifies effluent toxicity control mechanisms that will reduce effluent toxicity to the level necessary to meet no significant lethality at the critical dilution; and

6) any changes to the initial TRE Plan and Schedule that are believed necessary as a result of the TRE findings.

Copies of the TRE Activities Report shall also be submitted to the U.S. EPA Region 6 office.

e. During the TRE, the permittee shall perform, at a minimum, quarterly testing using the more sensitive species; testing for the less sensitive species shall continue at the frequency specified in Part 1.b.

f. If the effluent ceases to effect significant lethality (herein as defined below) the permittee may end the TRE. A "cessation of lethality" is defined as no significant lethality for a period of 12 consecutive months with at least monthly testing. At the end of the 12 months, the permittee shall submit a statement of intent to cease the TRE and may then resume the testing frequency specified in Part 1.b. The permittee may only apply the "cessation of lethality" provision once.

   This provision accommodate situations where operational errors and upsets, spills, or sampling errors triggered the TRE, in contrast to a situation where a single toxicant or group of toxicants cause lethality. This provision does not apply as a result of corrective actions taken by the permittee. "Corrective actions" are herein defined as proactive efforts which eliminate or reduce effluent toxicity. These include, but are not limited to, source reduction or elimination, improved housekeeping, changes in chemical usage, and modifications of influent streams and/or effluent treatment.

The permittee may only apply this cessation of lethality provision once. If the effluent again demonstrates significant lethality to the same species, the permit will be amended to add a WET limit with a compliance period, if appropriate. However, prior to the effective date of the WET limit, the permittee may apply for a permit amendment removing and replacing the WET limit with an alternate toxicity control measure by identifying and confirming the toxicant and/or an appropriate control measure.

g. The permittee shall complete the TRE and submit a Final Report on the TRE Activities no later than 28 months from the last test day of the retest that confirmed significant lethal effects at the critical dilution. The permittee may petition the Executive Director (in writing) for an extension of the 28-month limit. However, to warrant an extension the permittee must have demonstrated due diligence in their pursuit of the TIE/TRE and must prove that circumstances beyond their control stalled the TIE/TRE. The report shall provide information pertaining to the specific control mechanism(s) selected that will, when implemented, result in reduction of effluent toxicity to no significant lethality at the critical dilution. The report will also provide a specific corrective action schedule for implementing the selected control mechanism(s). A copy of the TRE Final Report shall also be submitted to the U.S. EPA Region 6 office.

h. Based upon the results of the TRE and proposed corrective actions, this permit may be amended to modify the biomonitoring requirements, where necessary, to require a compliance schedule for implementation of corrective actions, to specify a WET limit, to specify a BMP, and/or to specify CS limits.

TABLE 1 (SHEET 1 OF 4)

MYSID SHRIMP SURVIVAL AND GROWTH

		Date	Time		Date	Time
Dates and Times Composites Collected	No. 1 FROM:			TO:		
	No. 2 FROM:			TO:		
	No. 3 FROM:			TO:		

Test initiated:____________am/pm ____________date

Dilution water used: _____ Receiving water _____ Synthetic Dilution water

MYSID SHRIMP SURVIVAL

Percent Effluent	Percent Survival in Replicate Chambers								Mean Percent Survival			CV%*
	A	B	C	D	E	F	G	H	24h	48h	7 day	
0%												
5%												
7%												
10%												
13%												
17%												

* coefficient of variation = standard deviation x 100/mean

DATA TABLE FOR GROWTH OF MYSID SHRIMP

Replicate	Mean dry weight in milligrams in replicate chambers					
	0%	5%	7%	10%	13%	17%
A						
B						
C						
D						
E						

TABLE 1 (SHEET 2 OF 4)

MYSID SHRIMP SURVIVAL AND GROWTH

DATA TABLE FOR GROWTH OF MYSID SHRIMP (Continued)

Replicate	Mean dry weight in milligrams in replicate chambers					
	0%	5%	7%	10%	13%	17%
F						
G						
H						
Mean Dry Weight (mg)						
CV%*						
PMSD	Acceptable Range 11-37					

* coefficient of variation = standard deviation x 100/mean

1. Dunnett's Procedure or Steel's Many-One Rank Test or Wilcoxon Rank Sum Test (with Bonferroni adjustment) or t-test (with Bonferroni adjustment) as appropriate:

   Is the mean survival at 7 days significantly less (p=0.05) than the control survival for the % effluent corresponding to lethality?

   CRITICAL DILUTION (13%): ______ YES ______ NO

2. Dunnett's Procedure or Steel's Many-One Rank Test or Wilcoxon Rank Sum Test (with Bonferroni adjustment) or t-test (with Bonferroni adjustment) as appropriate:

   Is the mean dry weight (growth) at 7 days significantly less (p=0.05) than the control's dry weight (growth) for the % effluent corresponding to non-lethal effects?

   CRITICAL DILUTION (13%): ______ YES ______ NO

3. Enter percent effluent corresponding to each NOEC/LOEC below:

   a.) NOEC survival = ________% effluent

   b.) LOEC survival = ________% effluent

   c.) NOEC growth = ________% effluent

   d.) LOEC growth = ________% effluent

TABLE 1 (SHEET 3 OF 4)

INLAND SILVERSIDE LARVAL SURVIVAL AND GROWTH TEST

		Date Time		Date Time
Dates and Times Composites Collected	No. 1 FROM:	________________	TO:	________________
	No. 2 FROM:	________________	TO:	________________
	No. 3 FROM:	________________	TO:	________________

Test initiated:____________am/pm ____________date

Dilution water used: _____ Receiving water _____ Synthetic Dilution water

INLAND SILVERSIDE SURVIVAL

Percent Effluent	Percent Survival in Replicate Chambers					Mean Percent Survival			CV%*
	A	B	C	D	E	24h	48h	7 days	
0%									
5%									
7%									
10%									
13%									
17%									

* coefficient of variation = standard deviation x 100/mean

TABLE 1 (SHEET 4 OF 4)

INLAND SILVERSIDE LARVAL SURVIVAL AND GROWTH TEST

INLAND SILVERSIDE GROWTH

Percent Effluent	Average Dry Weight in milligrams in replicate chambers					Mean Dry Weight (mg)	CV%*
	A	B	C	D	E		
0%							
5%							
7%							
10%							
13%							
17%							
PMSD	Acceptable Range 11-28						

* coefficient of variation = standard deviation x 100/mean

Weights are for: ___ preserved larvae, or ___ unpreserved larvae

1. Dunnett's Procedure or Steel's Many-One Rank Test or Wilcoxon Rank Sum Test (with Bonferroni adjustment) or t-test (with Bonferroni adjustment) as appropriate:

   Is the mean survival at 7 days significantly less (p=0.05) than the control survival for the % effluent corresponding to lethality?

   CRITICAL DILUTION (13%): ______ YES ______ NO

2. Dunnett's Procedure or Steel's Many-One Rank Test or Wilcoxon Rank Sum Test (with Bonferroni adjustment) or t-test (with Bonferroni adjustment) as appropriate:

   Is the mean dry weight (growth) at 7 days significantly less (p=0.05) than the control's dry weight (growth) for the % effluent corresponding to non-lethal effects?

   CRITICAL DILUTION (13%): ______ YES ______ NO

3. Enter percent effluent corresponding to each NOEC/LOEC below:

   a.) NOEC survival = _________% effluent

   b.) LOEC survival = _________% effluent

   c.) NOEC growth = _________% effluent

   d.) LOEC growth = _________% effluent

24-HOUR ACUTE BIOMONITORING REQUIREMENTS: MARINE

The provisions of this Section apply individually and separately to Outfall 001 for whole effluent toxicity testing (biomonitoring). No samples or portions of samples from one outfall may be composited with samples or portions of samples from another outfall.

1. Scope, Frequency and Methodology

   a. The permittee shall test the effluent for lethality in accordance with the provisions in this Section. Such testing will determine compliance with the Surface Water Quality Standard, 30 TAC §307.6(e)(2)(B), of greater than 50% survival of the appropriate test organisms in 100% effluent for a 24-hour period.

   b. The toxicity tests specified shall be conducted once per six months. The permittee shall conduct the following toxicity tests utilizing the test organisms, procedures, and quality assurance requirements specified in this section of the permit and in accordance with "Methods for Measuring the Acute Toxicity of Effluents and Receiving Waters to Freshwater and Marine Organisms, Fifth Edition" (EPA-821-R-02-012), or the most recent update thereof:

      1) Acute 24-hour static toxicity test using the mysid shrimp (*Mysidopsis bahia*). A minimum of five replicates with eight organisms per replicate shall be used in the control and in each dilution.

      2) Acute 24-hour static toxicity test using the inland silverside (*Menidia beryllina*). A minimum of five replicates with eight organisms per replicate shall be used in the control and in each dilution.

      The permittee must perform and report a valid test for each test species during the prescribed reporting period. An invalid test must be repeated during the same reporting period. An invalid test is herein defined as any test failing to satisfy the test acceptability criteria, procedures, and quality assurance requirements specified in the test methods and permit. All test results, valid or invalid, must be submitted as described below.

   c. In addition to an appropriate control, a 100% effluent concentration shall be used in the toxicity tests. Except as discussed in item 2.b., the control and/or dilution water shall consist of a standard, synthetic, moderately hard, reconstituted water.

   d. This permit may be amended to require a Whole Effluent Toxicity (WET) limit, a Best Management Practice (BMP), a Chemical-Specific (CS) limit, additional toxicity testing, and/or other appropriate actions to address toxicity. The permittee may be required to conduct additional biomonitoring tests and/or a Toxicity Reduction Evaluation (TRE) if biomonitoring data indicate multiple numbers of unconfirmed toxicity events.

   e. If the biomonitoring dilution series specified in the Chronic biomonitoring requirements includes a 100% effluent concentration, those results may fulfill the requirements of this Section. The results of any test with a 100% effluent concentration performed in the proper time interval may be substituted in lieu of performing a separate 24-hour acute test. Compliance will be evaluated as specified in item a. The greater than 50% survival in 100% effluent for a 24-hour period standard applies to all tests utilizing a 100% effluent dilution, regardless of whether the results are submitted to comply with the minimum testing frequency defined in item b.

2. Required Toxicity Testing Conditions

   a. Test Acceptance - The permittee shall repeat any toxicity test, including the control, if the control fails to meet a mean survival equal to or greater than 90%.

   b. Dilution Water - In accordance with item 1.c., the control and/or dilution water shall normally consist of a standard, synthetic, reconstituted seawater. If the permittee is utilizing the results of a 48-Hour Acute test or a Chronic test to satisfy the requirements in item 1.e., the permittee may use the receiving water or dilution water that meets the requirements of item 2.a. as the control and dilution water.

c. Samples and Composites

1) The permittee shall collect one flow-weighted 24-hour composite sample from Outfall 001. A 24-hour composite sample consists of a minimum of 12 effluent portions collected at equal time intervals representative of a 24-hour operating day and combined proportional to flow, or a sample continuously collected proportional to flow over a 24-hour operating day.

2) The permittee shall collect the 24-hour composite samples such that the samples are representative of any periodic episode of chlorination, biocide usage, or other potentially toxic substance discharged on an intermittent basis.

3) The permittee shall initiate the toxicity tests within 36 hours after collection of the last portion of the 24-hour composite sample. Samples shall be maintained at a temperature of 0-6 degrees Centigrade during collection, shipping, and storage.

4) If the Outfall ceases discharging during the collection of the effluent composite sample, the requirements for the minimum number of effluent portions are waived. However, the permittee must have collected a composite sample volume sufficient for completion of the required test. The abbreviated sample collection, duration, and methodology must be documented in the full report required in Part 3 of this Section.

3. Reporting

All reports, tables, plans, summaries, and related correspondence required in any Part of this Section shall be submitted to the attention of the Water Quality Standards Team (MC 150) of the Water Quality Division. All DMRs, including DMRs with biomonitoring data, should be sent to the Water Quality Compliance Monitoring Team of the Enforcement Division (MC 224).

a. The permittee shall prepare a full report of the results of all tests conducted pursuant to this permit in accordance with the Report Preparation Section of "Methods for Measuring the Acute Toxicity of Effluents and Receiving Waters to Freshwater and Marine Organisms, Fifth Edition" (EPA-821-R-02-012), or the most recent update thereof, for every valid and invalid toxicity test initiated. All full reports shall be retained for three years at the plant site and shall be available for inspection by TCEQ personnel.

b. A full report must be submitted with the first valid biomonitoring test results for each test species and with the first test results any time the permittee subsequently employs a different test laboratory. Full reports need not be submitted for subsequent testing unless specifically requested. The permittee shall routinely report the results of each biomonitoring test on the Table 2 forms provided with this permit. All Table 2 reports must include the information specified in the Table 2 form attached to this permit.

1) Semiannual biomonitoring test results are due on or before January 20th and July 20th for biomonitoring conducted during the previous 6 month period.

2) Quarterly biomonitoring test results are due on or before January 20th, April 20th, July 20th, and October 20th, for biomonitoring conducted during the previous calendar quarter.

c. Enter the following codes on the DMR for the appropriate parameters for valid tests only:

1) For the mysid shrimp, Parameter TIE3E, enter a "0" if the mean survival at 24-hours is greater than 50% in the 100% effluent dilution; if the mean survival is less than or equal to 50%, enter a "1."

2) For the inland silverside, Parameter TIE6B, enter a "0" if the mean survival at 24-hours is greater than 50% in the 100% effluent dilution; if the mean survival is less than or equal to 50%, enter a "1."

d. Enter the following codes on the DMR for retests only:

1) For retest number 1, Parameter 22415, enter a "0" if the mean survival at 24-hours is greater than 50% in the 100% effluent dilution; if the mean survival is less than or equal to 50%, enter a "1."

2) For retest number 2, Parameter 22416, enter a "0" if the mean survival at 24-hours is greater than 50% in the 100% effluent dilution; if the mean survival is less than or equal to 50%, enter a "1."

4. Persistent Mortality

The requirements of this Part apply when a toxicity test demonstrates significant lethality, here defined as a mean mortality of 50% or greater to organisms exposed to the 100% effluent concentration after 24-hours.

a. The permittee shall conduct two additional tests (retests) for each species that demonstrates significant lethality. The two retests shall be conducted once per week for two weeks. Five effluent dilution concentrations in addition to an appropriate control shall be used in the retests. These additional effluent concentrations shall be 6%, 13%, 25%, 50% and 100% effluent. The first retest shall be conducted within 15 days of the laboratory determination of significant lethality. All test results shall be submitted within 20 days of test completion of the second retest. Test completion is defined as the 24th hour. The retests shall also be reported on the DMRs as specified in Part 3.d.

b. If one or both of the two retests specified in item 4.a. demonstrates significant lethality, the permittee shall initiate the TRE requirements as specified in Part 5 of this Section.

5. Toxicity Reduction Evaluation

a. Within 45 days of the retest that demonstrates significant lethality, the permittee shall submit a General Outline for initiating a TRE. The outline shall include, but not be limited to, a description of project personnel, a schedule for obtaining consultants (if needed), a discussion of influent and/or effluent data available for review, a sampling and analytical schedule, and a proposed TRE initiation date.

b. Within 90 days of the retest that demonstrates significant lethality, the permittee shall submit a TRE Action Plan and Schedule for conducting a TRE. The plan shall specify the approach and methodology to be used in performing the TRE. A Toxicity Reduction Evaluation is a step-wise investigation combining toxicity testing with physical and chemical analysis to determine actions necessary to eliminate or reduce effluent toxicity to a level not effecting significant lethality at the critical dilution. The TRE Action Plan shall lead to the successful elimination of significant lethality for both test species defined in item 1.b. As a minimum, the TRE Action Plan shall include the following:

1) Specific Activities - The TRE Action Plan shall specify the approach the permittee intends to utilize in conducting the TRE, including toxicity characterizations, identifications, confirmations, source evaluations, treatability studies, and/or alternative approaches. When conducting characterization analyses, the permittee shall perform multiple characterizations and follow the procedures specified in the document entitled, "Methods for Aquatic Toxicity Identification Evaluations: Phase I Toxicity Characterization Procedures" (EPA/600/6-91/003), or alternate procedures. The permittee shall perform multiple identifications and follow the methods specified in the documents entitled, "Methods for Aquatic Toxicity Identification Evaluations, Phase II Toxicity Identification Procedures for Samples Exhibiting Acute and Chronic Toxicity" (EPA/600/R-92/080) and "Methods for Aquatic Toxicity Identification Evaluations, Phase III Toxicity Confirmation Procedures for Samples Exhibiting Acute and Chronic Toxicity" (EPA/600/R-92/081). All characterization, identification, and confirmation tests shall be conducted in an orderly and logical progression;

2) Sampling Plan - The TRE Action Plan should describe sampling locations, methods, holding times, chain of custody, and preservation techniques. The effluent sample volume collected for all tests shall be adequate to perform the toxicity characterization/ identification/ confirmation

procedures, and chemical-specific analyses when the toxicity tests show significant lethality. Where the permittee has identified or suspects specific pollutant(s) and/or source(s) of effluent toxicity, the permittee shall conduct, concurrent with toxicity testing, chemical-specific analyses for the identified and/or suspected pollutant(s) and/or source(s) of effluent toxicity;

3) Quality Assurance Plan - The TRE Action Plan should address record keeping and data evaluation, calibration and standardization, baseline tests, system blanks, controls, duplicates, spikes, toxicity persistence in the samples, randomization, reference toxicant control charts, as well as mechanisms to detect artifactual toxicity; and

4) Project Organization - The TRE Action Plan should describe the project staff, project manager, consulting engineering services (where applicable), consulting analytical and toxicological services, etc.

c. Within 30 days of submittal of the TRE Action Plan and Schedule, the permittee shall implement the TRE with due diligence.

d. The permittee shall submit quarterly TRE Activities Reports concerning the progress of the TRE. The quarterly TRE Activities Reports are due on or before April 20th, July 20th, October 20th, and January 20th. The report shall detail information regarding the TRE activities including:

1) results and interpretation of any chemical-specific analyses for the identified and/or suspected pollutant(s) performed during the quarter;

2) results and interpretation of any characterization, identification, and confirmation tests performed during the quarter;

3) any data and/or substantiating documentation which identifies the pollutant(s) and/or source(s) of effluent toxicity;

4) results of any studies/evaluations concerning the treatability of the facility's effluent toxicity;

5) any data which identifies effluent toxicity control mechanisms that will reduce effluent toxicity to the level necessary to eliminate significant lethality; and

6) any changes to the initial TRE Plan and Schedule that are believed necessary as a result of the TRE findings.

Copies of the TRE Activities Report shall also be submitted to the U.S. EPA Region 6 office.

e. During the TRE, the permittee shall perform, at a minimum, quarterly testing using the more sensitive species; testing for the less sensitive species shall continue at the frequency specified in Part 1.b.

f. If the effluent ceases to effect significant lethality (herein as defined below) the permittee may end the TRE. A "cessation of lethality" is defined as no significant lethality for a period of 12 consecutive weeks with at least weekly testing. At the end of the 12 weeks, the permittee shall submit a statement of intent to cease the TRE and may then resume the testing frequency specified in Part 1.b. The permittee may only apply the "cessation of lethality" provision once.

This provision accommodate situations where operational errors and upsets, spills, or sampling errors triggered the TRE, in contrast to a situation where a single toxicant or group of toxicants cause lethality. This provision does not apply as a result of corrective actions taken by the permittee. "Corrective actions" are herein defined as proactive efforts which eliminate or reduce effluent toxicity. These include, but are not limited to, source reduction or elimination, improved housekeeping, changes in chemical usage, and modifications of influent streams and/or effluent treatment.

The permittee may only apply this cessation of lethality provision once. If the effluent again demonstrates significant lethality to the same species, the permit will be amended to add a WET limit with a compliance period, if appropriate. However, prior to the effective date of the WET limit, the permittee may apply for a permit amendment removing and replacing the WET limit with an alternate toxicity control measure by identifying and confirming the toxicant and/or an appropriate control measure.

g. The permittee shall complete the TRE and submit a Final Report on the TRE Activities no later than 18 months from the last test day of the retest that demonstrates significant lethality. The permittee may petition the Executive Director (in writing) for an extension of the 18-month limit. However, to warrant an extension the permittee must have demonstrated due diligence in their pursuit of the TIE/TRE and must prove that circumstances beyond their control stalled the TIE/TRE. The report shall specify the control mechanism(s) that will, when implemented, reduce effluent toxicity as specified in item 5.g. The report will also specify a corrective action schedule for implementing the selected control mechanism(s). A copy of the TRE Final Report shall also be submitted to the U.S. EPA Region 6 office.

h. Within 3 years of the last day of the test confirming toxicity, the permittee shall comply with 30 TAC 307.6.(e)(2)(B), which requires greater than 50% survival of the test organism in 100% effluent at the end of 24-hours. The permittee may petition the Executive Director (in writing) for an extension of the 3-year limit. However, to warrant an extension the permittee must have demonstrated due diligence in their pursuit of the TIE/TRE and must prove that circumstances beyond their control stalled the TIE/TRE.

The requirement to comply with 30 TAC 307.6.(e)(2)(B) may be exempted upon proof that toxicity is caused by an excess, imbalance, or deficiency of dissolved salts. This exemption excludes instances where individually toxic components (e.g. metals) form a salt compound. Following the exemption, the permit may be amended to include an ion-adjustment protocol, alternate species testing, or single species testing.

i. Based upon the results of the TRE and proposed corrective actions, this permit may be amended to modify the biomonitoring requirements where necessary, to require a compliance schedule for implementation of corrective actions, to specify a WET limit, to specify a BMP, and/or to specify a CS limit.

TABLE 2 (SHEET 1 OF 2)

MYSID SHRIMP SURVIVAL

GENERAL INFORMATION

	Time (am/pm)	Date
Composite Sample Collected		
Test Initiated		

PERCENT SURVIVAL

Time	Rep	Percent effluent (%)					
		0%	6%	13%	25%	50%	100%
24h	A						
	B						
	C						
	D						
	E						
	MEAN						

1. Enter percent effluent corresponding to the LC50 below:

24 hour LC50 = _______% effluent

95% confidence limits: _______________

Method of LC50 calculation:____________

TABLE 2 (SHEET 2 OF 2)

INLAND SILVERSIDE SURVIVAL

GENERAL INFORMATION

	Time (am/pm)	Date
Composite Sample Collected		
Test Initiated		

PERCENT SURVIVAL

Time	Rep	Percent effluent (%)					
		0%	6%	13%	25%	50%	100%
24h	A						
	B						
	C						
	D						
	E						
	MEAN						

1. Enter percent effluent corresponding to the LC50 below:

   24-hour LC50 = _______% effluent

   95% confidence limits: _______________

   Method of LC50 calculation:____________

STP Attachment 18

Creating Baseload Wind Power Systems Using Advanced Compressed Air Energy Storage Concepts

BACKGROUND/OVERVIEW

Greatly expanded use of wind energy has been proposed to reduce dependence on fossil and nuclear fuels for electricity generation. The large-scale deployment of wind energy is ultimately limited by its intermittent output and the remote location of high-value wind resources, particularly in the United States. Wind energy systems that combine wind turbine generation with energy storage and long-distance transmission may overcome these obstacles and provide a source of power that is functionally equivalent to a conventional baseload electric power plant. A "baseload wind" system can produce a stable, reliable output that can replace a conventional fossil or nuclear baseload plant, instead of merely supplementing its output. This type of system could provide a large fraction of a region's electricity demand, far beyond the 10-20% often suggested as an economic upper limit for conventional wind generation deployed without storage.

THE BASELOAD WIND CONCEPT

The basic components of a baseload wind system, illustrated in **Figure 1**, include a large amount of wind generation, a large-scale energy storage system, and long-distance transmission.

Compressed air energy storage (CAES) is a hybrid generation/storage technology well-suited for use in the baseload wind concept. CAES systems, illustrated in **Figure 2**, are based on conventional gas turbine technology and use the elastic potential energy of compressed air. Energy is stored by compressing air in an airtight underground storage cavern. To extract the stored energy, compressed air is drawn from the storage vessel, heated, and then expanded through a high-pressure turbine that captures some of the energy in the compressed air. The air is then mixed with fuel and combusted, with the exhaust expanded through a low-pressure gas turbine. The turbines are connected to an electrical generator.

As part of a baseload wind system, CAES would be used to enable a nearly constant output by smoothing the highly variable output from wind turbine generation. **Figure 3** illustrates how the combination of 2,000 MW of wind and 900 MW of CAES could be combined to produce a nearly constant 900 MW output. When operating at a high capacity factor (>75%), about 60-80% of the wind energy (averaged over a year) is placed directly onto the grid, while the remainder is stored (to be retrieved when the wind energy output falls below average) or "spilled" (due to limits of the storage cavern and transmission capacity).

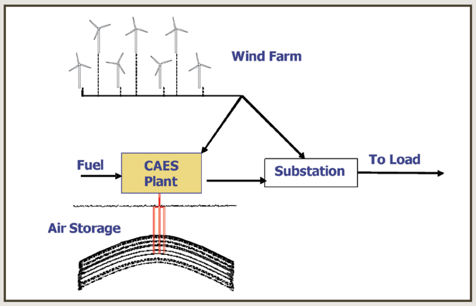

Figure 1. Simplified Shematic of a Wind/CAES Power Plant

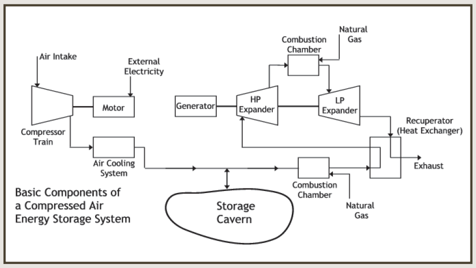

Figure 2. Basic Components of a Compressed Air Energy Storage System

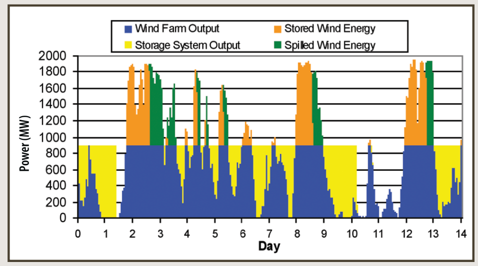

Figure 3. Sample Baseload Wind Generator Output (Target Output = 900 MW)

TECHNICAL AND ENVIRONMENTAL PERFORMANCE

The baseload wind power plant can achieve varying levels of performance in terms of expected capacity factor. Actual performance is dependent on optimizing the system component size and the tradeoff between high annual capacity factor and utilization of wind energy. **Figure 4** illustrates the energy flow through a baseload wind plant for a variety of possible scenarios.

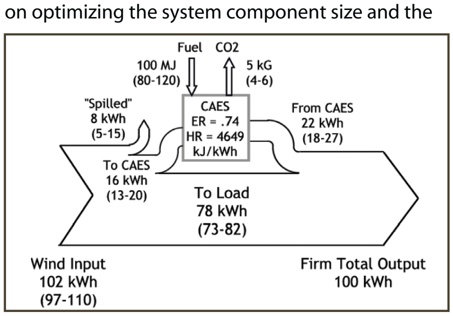

Figure 4: Energy Flow through a Baseload Wind Power Plant

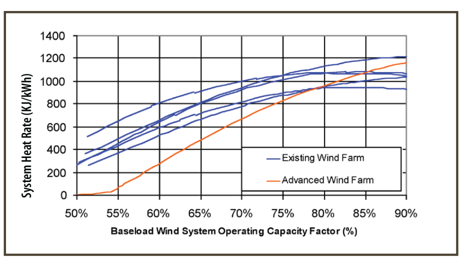

Figure 5: Baseload Wind Plant Fuel Requirements

The use of "conventional" CAES requires around 4,600 kJ of natural gas for each unit of energy stored by the CAES system. However, most wind energy does not need to be stored, so the effective "heat rate" of the entire baseload wind power plant is substantially less. **Figure 5** illustrates that a baseload wind plant operating at a high capacity factor will require around 1,000 kJ of fuel for each kWh placed onto the grid. Several cases are illustrated, using data from existing wind farms, and also simulations of advanced wind farms in higher quality wind resource regions. Use of natural gas fuel in the CAES system also leads to greenhouse emissions of about 40 to 80 g/kWh.

ADVANCED WIND/CAES CONCEPTS

In addition to greenhouse gas emissions, the use of natural gas in CAES systems results in additional fuel price risk. Replacing natural gas with synfuel derived from local, more stable fuel sources is a possible alternative. One possible fuel source is gasified biomass, which eliminates the use of fossil fuels, virtually eliminating net CO_2 emissions from the system. In addition, by deriving energy completely from farm sources, this type of system may reduce some opposition to long distance transmission lines in rural areas, which may be an obstacle to large-scale wind deployment. Coal-derived syngas is another alternative in areas with existing coal mining infrastructure and where local economies are dependent in part on coal-extraction industries.

While the current penetration of wind energy is far too low to require energy storage, projected growth in the installed base of wind generation motivates thinking about scenarios of extremely large use of wind energy. Development of the "baseload" wind concept will require a greater understanding of the local geologic compatibility of air storage, and additional work will be required to examine the feasibility of advanced wind/CAES concepts described here.

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SEAC Strategic Energy Analysis Center

CU Energy Initiative/NREL Symposium
University of Colorado, Boulder
October 3, 2006
NREL/PO-640-40674

STP Attachment 19

Luminant

SHARE

News Release

07.27.07

Luminant and Shell Join Forces to Develop a Texas-Sized Wind Farm
-

Shell WindEnergy Inc. and Luminant, a subsidiary of TXU Corp., announced today a joint development agreement for a 3,000-megawatt wind project in the Texas Panhandle and to work together on other renewable energy developments in Texas.

Shell and Luminant will also explore the use of compressed air storage, in which excess power could be used to pump air underground for later use in generating electricity. This technology will further improve reliability and grid usage and becomes more economical with large-scale projects, such as proposed for Briscoe County.

Recent testimony by Shell before the Public Utility Commission of Texas demonstrated the Briscoe County project could deliver the lowest-cost wind energy for consumers. This low cost is driven by excellent wind resources and the comparatively lower cost to bring that energy to market from the Texas Panhandle region.

"Shell is constantly looking for solutions to deal with climate change and increasing our energy diversity. Wind is part of the answer. Our approach is a cost-effective solution for consumers," said John Hofmeister, president of Shell Oil Company.

“Luminant is committed to providing Texans with clean sources of energy, and this agreement with Shell is a real next step in delivering on that commitment” said Mike Childers, CEO of Luminant Development. “Luminant is already the state leader in wind-energy purchases, and co-developing this project would take us a long way toward our goal of doubling our portfolio.”

About Shell

Shell WindEnergy Inc. is a subsidiary of Shell Oil Company. "Shell WindEnergy" refers to the companies of the Royal Dutch Shell PLC that are engaged in the pursuit and development globally of businesses related to wind power generation. Each of the companies that make up the Royal Dutch Shell PLC is an independent entity and has its own separate identity. Principal offices of Shell WindEnergy are located in The Hague, the Netherlands, with a regional base in Houston. For further information, please visit www.shell.com/wind.

Shell Oil Company, including its consolidated companies and its share in equity companies, is one of America's leading oil and natural gas producers, natural gas marketers, gasoline marketers and petrochemical manufacturers. Shell, a leading oil and gas producer in the deepwater Gulf of Mexico, is a recognized pioneer in oil and gas exploration and production technology. Shell Oil Company is an affiliate ofthe Shell Group,a global group of energy and petrochemical companies, employing approximately 109,000 people and operating in more than 130 countries and territories.

About Luminant

Luminant, a subsidiary of TXU Corp., is a competitive power generation business, including mining, wholesale marketing and trading, construction and development operations. Luminant has over 18,300 MW of generation in Texas, including 2,300 MW of nuclear and 5,800 MW of coal-fueled generation capacity. Luminant is also the largest purchaser of wind-generated electricity in Texas and fifth largest in the United States. TXU Corp. is a Dallas-based energy holdingcompany that has a portfolio of competitive and regulated energy subsidiaries, primarily in Texas. Visit www.txucorp.com for more information about Luminant and TXU Corp.

Media
Tom Kleckner
214-812-3206

Shell Media Line
713-241-4544

Back to the Press Releases Index

STP Attachment 20

Sustainability Research

Boise State University

Office of Energy Research, Policy and Campus Sustainability

Overview of Compressed Air Energy Storage

ER-07-001

Overview of Compressed Air Energy Storage

Prepared by
John Gardner, Ph.D., P.E.[1]
Todd Haynes, M.E., EIT[2]
Boise State University
December 2007

Overview:

Compressed Air Energy Storage (CAES) is the term given to the technique of storing energy as the potential energy of a compressed gas. Usually it refers to air pumped into large storage tanks or naturally occurring underground formations. While the technique has historically been used to provide the grid with a variety of ancillary services, it is gaining attention recently as a means of addressing the intermittency problems associated with wind turbine electrical generators.

Figure 1 shows a schematic of the approach.

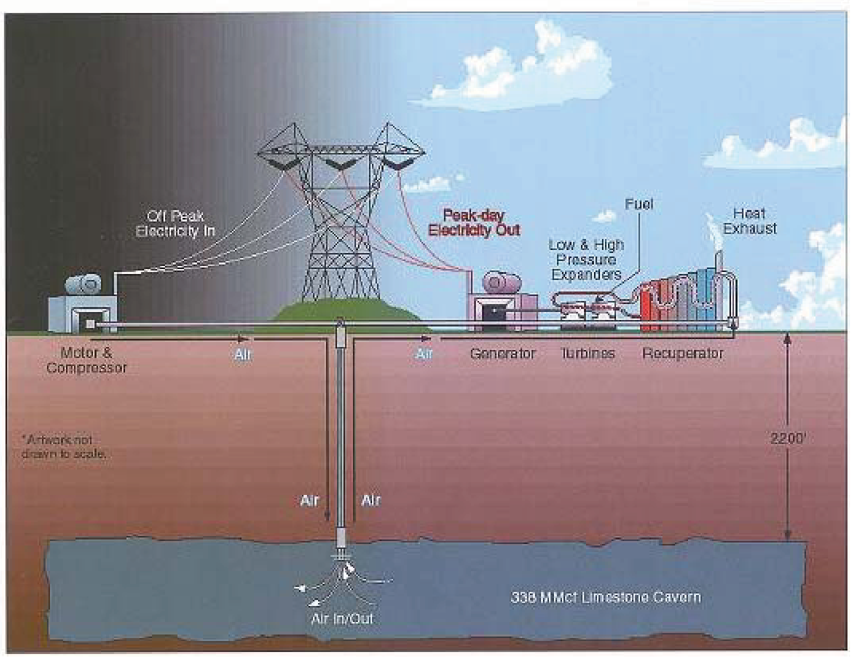

Figure 1: Conceptual representation of CAES (from http://www.caes.net/)

When energy is available, it is used to run air compressors which pump air into the storage cavern. When electricity is needed, it is expanded through conventional gas

[1] Associate VP for Energy Research, Policy and Campus Sustainability

[2] Energy Systems and Research Engineer

turbine expanders. Note that some additional energy (typically natural gas) is used during the expansion process to ensure that maximum energy is obtained from the compressed air (albeit as much as 67% less gas than would be used for an equivalent amount of electricity using gas turbine generators without CAES).

History:

Huntorf Plant

The world's first compressed air storage power station, the Huntorf Plant has been operational since 1978. The 290 MW plant, located in Bremen, Germany, is used to provide peak shaving, spinning reserves and VAR support. A total volume of 11 million cubic feet is stored at pressures up to 1000 psi in two underground salt caverns, situated 2100-2600 feet below the surface. It requires 12 hours of off-peak power to fully recharge, and then is capable of delivering full output (290 MW) for up to 4 hours. This system operates a conventional cycle and combusts natural gas prior to expansion.[3]

McIntosh

Alabama's Electric Cooperative (AEC) has been running the world's second CAES facility since 1991. Called the McIntosh project, it's a 110 MW unit. This commercial venture is used to store off-peak power, generate peak power and provide spinning reserve. 19 million cubic feet is stored at pressures up to 1080 psi in a salt cavern up to 2500 feet deep and can provide full power output for 26 hours. This system recovers waste heat which reduces fuel consumption by ~25% compared to the Huntorf Plant.[3]
http://www.caes.net/mcintosh.html

Iowa Stored Energy Park

Announced in January of 2007, the Iowa Stored Energy Park is partnership between the Iowa Association of Municipal Utilities and the Department of Energy. They plan to integrate a 75 to 150 MW wind farm with underground CAES, 3000 ft below the surface. The ISEP is currently in design phase with anticipated generation starting in 2011.
http://www.isepa.com.

General Compression

A start-up company in the Boston area has teamed up with a compressor company (Mechanology) to produce the world's first wind turbine-air compressor. These new wind turbines will have the capacity of approximately 1.5 MW, but instead of generating electricity, each wind turbine will pump air into CAES. This approach has the potential for saving money and improving overall efficiency by eliminating the intermediate and unnecessary electrical generation between the turbine and the air compressor.
http://generalcompression.com

STP Attachment 21

NUREG-1555

U.S. NUCLEAR REGULATORY COMMISSION

ENVIRONMENTAL STANDARD REVIEW PLAN

OFFICE OF NUCLEAR REACTOR REGULATION

STANDARD REVIEW PLANS FOR ENVIRONMENTAL REVIEWS FOR NUCLEAR POWER PLANTS

October 1999

OFFICE OF NUCLEAR REACTOR REGULATION
U.S. NUCLEAR REGULATORY COMMISSION

USNRC ENVIRONMENTAL STANDARD REVIEW PLAN

Environmental standard review plans are prepared for the guidance of the Office of Nuclear Reactor Regulation staff responsible for environmental reviews for nuclear power plants. These documents are made available to the public as part of the Commission's policy to inform the nuclear industry and the general public of regulatory procedures and policies. Environmental standard review plans are not substitutes for regulatory guides or the Commission's regulations and compliance with them is not required. The environmental standard review plans are keyed to Preparation of Environmental Reports for Nuclear Power Stations.

Published environmental standard review plans will be revised periodically, as appropriate, to accommodate comments and to reflect new information and experience.

Comments and suggestions for improvement will be considered and should be sent to the U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Washington, D.C. 20555-0001.

U.S. NUCLEAR REGULATORY COMMISSION

ENVIRONMENTAL STANDARD REVIEW PLAN

OFFICE OF NUCLEAR REACTOR REGULATION

4.4.1 PHYSICAL IMPACTS

REVIEW RESPONSIBILITIES

Primary—Appendix B

Secondary—Appendix B

I. AREAS OF REVIEW

This environmental standard review plan (ESRP) directs the staff's identification and assessment of the direct physical impacts of construction-related activities[a] to the community. Among these are the construction disturbances of noise, odors, vehicle exhaust, dust, vibration, and shock from blasting.

The scope of the review directed by this plan should include consideration of impacts resulting from plant construction, transmission corridors and access roads, other offsite facilities, and project-related transportation of goods and materials. The review should be of sufficient detail to predict and assess potential impacts and to show how these impacts should be treated in the licensing process. Where necessary, the reviewer should identify alternative locations, designs, practices, and procedures that would mitigate predicted adverse impacts.

Review Interfaces

The reviewer for this ESRP should obtain input from or provide input to the reviewers for the following ESRPs, as indicated:

- ESRPs 2.1 and 2.2. Obtain a detailed description of the plant location and of the surrounding region affected by the plant construction.

(a) Construction-related activities are those that occur solely as a result of plant construction.

- ESRP 2.3.2. Obtain descriptions of bodies of water likely to be affected by noise, odor, transportation, or construction or whose aesthetics would be affected.

- ESRPs 2.5.1 and 2.5.2. Obtain the socioeconomic features such as population and community characteristics of the site environs that potentially may be subject to physical impacts from construction.

- ESRP 2.7. Obtain estimates of the impacts of non-radiological emissions related to plant construction on air quality.

- ESRP 3.1. Obtain any aspects of the plant's appearance that may cause physical impacts in the region, including visual aesthetics.

- ESRP 3.7. Provide a detailed description of any power transmission system construction associated with the plant that may physically impact the region, including visual aesthetics.

- ESRPs 4.1.1 through 4.1.2. Obtain data on land uses likely to be affected physically or aesthetically by construction noise, odors, dust, etc. at the plant and along transmission and access corridors. Of special concern are nearby recreation areas.

- ESRP 4.2.2. Obtain data on construction activities that may have adverse impacts on noise, odors, dust, shock, vibration, or aesthetics in the vicinity of the plant and transmission and access corridors.

- ESRP 4.6. Provide a list of the applicant's commitments and the practices that the staff identified to limit adverse environmental impacts of construction.

- ESRP 5.8.1. Provide the features of plant construction expected to result in operational impacts.

- ESRPs 9.3 and 9.4. Provide a request to the reviewers for ESRPs 9.3 and 9.4 to consider alternative plant designs, locations, or construction practices that would avoid the impacts if the reviewer determines that there are physical impacts of construction that are adverse and should be avoided.

- ESRP 10.1. Provide a list of the unavoidable physical impacts that are predicted to occur as a result of the proposed construction activity.

- Interface with Environmental Project Manager (EPM). Consult with the EPM on practicality and cost effectiveness of any proposed modifications to mitigate physical socioeconomic impacts of construction.

Data and Information Needs

The type of data and information needed will be affected by site- and station-specific factors, and the degree of detail should be modified according to the anticipated magnitude of the potential impacts. The following information should be obtained:

- the distribution of people, buildings, roads, and recreational facilities vulnerable to impact from construction-related activities (from the environmental report [ER] and consultation with Federal, State, regional, local, and affected Native American tribal agencies).

- applicable standards for levels of noise, dust, and gaseous pollutants (from consultation with Federal, State, regional, local, and affected Native American tribal agencies)

- predicted noise levels at sensitive areas identified in the first item listed above (from the ER)

- predicted air pollutant levels at sensitive areas identified in the first item listed above (from the ER).

II. ACCEPTANCE CRITERIA

Acceptance criteria are based on meeting the relevant requirements for noise, dust, air pollution, and visual aesthetics of the following regulations:

- Clean Air Act of 1970, as amended, with respect to air quality during construction activities.

- 40 CFR 50-90 as related to National Primary and Secondary Air Quality Standards.

- Noise Control Act of 1972, as amended, with respect to noise from construction.

- 10 CFR 51.71 and 10 CFR 51.45 with respect to describing the significance or potential significance of physical impacts of plant-construction activities on nearby communities.

Regulatory positions and specific criteria necessary to meet the regulations identified above are as follows:

- Regulatory Guide 4.2, Rev. 2, *Preparation of Environmental Reports for Nuclear Power Stations* (NRC 1976), with respect to economic and social impact of siting and construction activities.

Technical Rationale

The technical rationale for evaluating the applicant's potential physical impacts is discussed in the following paragraphs:

In accordance with 10 CFR 51.45(d), the applicant is required to submit in the ER information needed for evaluating socioeconomic impacts of construction. Similar information is required to be present in the EIS pursuant to 10 CFR 51.71.

Reasonably detailed information about the potential for physical socioeconomic impacts such as noise or dust at the site in question is required to assess any potential social or economic impacts that might occur as a result of plant construction or operation. Data in the ER must be adequate to make these determinations.

III. REVIEW PROCEDURES

The reviewer's analysis of construction impacts on the community should be linked to the environmental reviews directed by ESRPs 2.1, 2.2, 2.5.1, 2.5.2, 3.1 and 3.7 to ensure that the environmental factors most likely to be impacted by the proposed construction are adequately described. The reviewer should ensure that information presented in the applicant's ER is complete and accurate. The reviewer should recognize that physical impacts to a community from construction of a nuclear plant are not markedly different from any other large heavy construction project. With this in mind, the reviewer should take the following steps:

(1) For any particular construction related activity, first consider the distribution of residents and transients who could be affected, including determination of sensitive use patterns (e.g., hospitals, residences, recreational areas) and the allowable limits of impacts.

(2) Identify the potential impacts on the community and predict their extent and magnitude, including impacts from dust, noise, shock from blasting, and polluting gases and particles.

- Consider impacts in qualitative terms where the effect on the community is expected to be minor.

- Where adverse impacts (i.e., impacts that should be mitigated or avoided) can be predicted, conduct a more detailed analysis and where practical, make quantitative estimates of the magnitude of the impacts.

(3) Identify the applicant's commitments to mitigate the physical impacts. These include

- wetting down roadways and construction sites

- scheduling noisy operations during daytime hours

- suppressing blast and shock effects by using mats.

(4) Consider the major physical impacts of plant construction. The specific impacts should include the impact of construction on transportation and the aesthetic characteristics of the region.

(5) Become familiar with the provisions of standards, guides, and agreements pertinent to the construction of nuclear power plants.

(6) Refer to the "Acceptance Criteria" section of this ESRP for a list of those generally pertinent to this environmental review.

(7) Consult with appropriate Federal, State, regional, local, and affected Native American tribal agencies to verify that current, applicable regulations and guides are available. This should include, for example, consultation with the EPA and State and local agencies for current ambient air quality standards and air pollutant levels and Occupational Safety and Health Administration guidelines and standards applicable to facility construction.

(8) Verify that the applicant has made commitments to comply with these applicable regulations and guides.

(9) Become familiar with general references on construction practices and impacts.

(10) Examine proposed construction activities in light of recognized "good practice." The term "good practice" as used here refers to those activities that tend to mitigate noise levels and adverse construction impacts on the community.

IV. EVALUATION FINDINGS

The review conducted under this plan should be directed toward accomplishing the following objectives: (1) public disclosure of physical impacts resulting from construction related activities, (2) presentation of the basis for the staff analysis, and (3) presentation of staff conclusions regarding physical impacts of construction related activities to the community.

If the site is remote from a community and the applicant is committed to meeting applicable guides and standards and to following good construction practices, these facts should be stated with only a very brief discussion noting that under these conditions, physical socioeconomic impacts should be minor. Where this is not the case, each of the areas identified in the analysis section should be addressed briefly with conclusions regarding the significance of the impact on the community. The reviewer should discuss the applicant's commitments to meet applicable Federal, State, regional, local, and affected Native American tribal standards and should describe mitigating actions that should be taken by the applicant during construction. If there are some unique impacts resulting from unusual methods, materials, or other construction related activities, these impacts should be addressed in detail.

If the reviewer determines that the applicant is committed to complying with all applicable standards and that the applicant's proposed construction related activities represent good construction practices, the reviewer may conclude that the impacts resulting from these activities will be acceptable.

Where predicted impacts are adverse, the reviewer should consider mitigative measures, including alternative placement of structures, alternative schedules, alternative construction practices, or other conditions to be imposed by the construction permit.

Evaluation of each identified impact should result in one of the following determinations:

- *The impact is minor, and mitigation is not required.* When all impacts are of this nature, the reviewer should include a statement in the EIS of the following type:

    The staff reviewed the available information on the physical impacts of construction. Based on this review, the staff concludes that there are no significant physical socioeconomic environmental impacts as a result of construction.

- *The impact is adverse, but can be mitigated by specific design or procedure modifications that the reviewer has identified and determined to be practical*. For these cases, the reviewer should consult with the EPM and the reviewers for ESRPs 9.3 and 9.4 for verification that the mitigation measures are practical and will lead to an improvement in the benefit-cost balance. The reviewer should prepare lists of verified modifications for the reviewer for ESRP 4.6.

  A statement similar to the following should be included in the EIS:

    The staff reviewed the information on physical impacts of construction. Based on this review, the staff concludes that the following impacts require mitigation.

- *The impact is adverse and cannot be successfully mitigated, and is of such magnitude that it should be avoided.* When impacts of this nature are identified, the reviewer should inform the reviewers for ESRPs 9.3 and 9.4 that an analysis and evaluation of alternative designs or procedures is needed. The reviewer should participate in any such analysis and evaluation of alternatives that would avoid the impact and that could be considered practical. If no such alternatives can be identified, the reviewer is responsible for providing this information to the reviewer for ESRP 10.1.

  A statement similar to the following should be included in the EIS:

    The staff reviewed the information on physical impacts of construction. Based on this review, the staff concludes that the following impact(s) cannot be mitigated and should be avoided. Alternatives should be considered.

V. IMPLEMENTATION

The method described herein will be used by the staff in evaluating conformance with the Commission's regulations, except in those cases in which the applicant proposes an acceptable alternative for complying with specified portions of the regulations.

VI. <u>REFERENCES</u>

10 CFR 51.45, "Environmental report."

10 CFR 51.71, "Draft environmental impact statement—contents."

40 CFR 50-90, as related to National Primary and Secondary Air Quality Standards.

Clean Air Act Amendments of 1977, as amended, 41 USC 7401 et seq.

Noise Control Act, as amended, 42 USC 4901 et seq.

U.S. Nuclear Regulatory Commission (NRC). 1976. *Preparation of Environmental Reports for Nuclear Power Stations*. Regulatory Guide 4.2, Rev. 2, Washington, D.C.

U.S. NUCLEAR REGULATORY COMMISSION

ENVIRONMENTAL STANDARD REVIEW PLAN

OFFICE OF NUCLEAR REACTOR REGULATION

9.2.2 ALTERNATIVES REQUIRING NEW GENERATING CAPACITY

REVIEW RESPONSIBILITIES

Primary—Appendix B

Secondary—Appendix B

I. AREAS OF REVIEW

This environmental standard review plan (ESRP) directs the staff's identification and review of alternative sources of energy that could reasonably be expected to meet the demand from both a load and economic standpoint for additional generating capacity determined for the proposed project. Energy sources selected by this review will be compared with the proposed project by the reviewer for ESRP 9.2.3. The scope of the review directed by this plan will be governed by consideration of national policy, by site- and region-specific factors, and by the extent to which the energy sources may be considered as commercially exploitable. Within this scope, the reviewer should determine the current and projected status of (1) alternatives not yet commercially available, (2) fossil fuels, taking into account national policy regarding their use as fuels, and (3) alternatives uniquely available within the region (e.g., hydropower).

In performing this review, the reviewer may rely on the analysis in the applicant's environmental report (ER) and/or State or regional authorities' analyses concerning the need for power and energy supply alternatives. The reviewer should ensure that the analysis of the need for power and alternatives is reasonable and meets high quality standards.

The guidance in this ESRP is limited because the regulatory environment for electrical generating facilities is changing. Reviewers of issues related to need for power and evaluation of alternatives must know current NRC policy before beginning their review. Deregulation of utilities and open access to power-transmission systems should have a significant impact on the analysis of need for power, on the competition for cheaper power, and on the service area. Because of deregulation in bulk sales markets for electricity, the advent of independent power producers, and the increased use of purchases and exchanges of electricity among utilities to meet demand, the demand for electricity by ultimate customers within a utility's traditional service area increasingly is not met by the utility's own generating resources.

Trading of electricity will be further facilitated by the Federal Energy Regulatory Commission's (FERC's) final rule (61 FR 21540) requiring all public utilities that own, control, or operate facilities used for transmitting electric energy in interstate commerce to have on file open-access nondiscriminatory transmission tariffs that contain minimum terms and conditions on nondiscriminatory service.

The term "relevant service area" is used here to indicate any region to be served by the proposed facility, whether or not it corresponds to a traditional utility service area. Relevant service area is a situation-specific concept, and it must be defined on a case-by-case basis. Applicants may be power generators rather than a utility; therefore, analysis of existing and projected capacity and alternatives must be sufficiently flexible to accommodate differences in the applicant types and regulatory environments. The concept of "relevant region" is also introduced here to mean an area for which electricity-demand forecasts are done, such as the Northeast Power Coordinating Council region, that would usually include the relevant service area.

Review Interfaces

The reviewer for this ESRP should obtain input from or provide input to the reviewers for the following ESRPs, as indicated:

- ESRP 8.1-8.4. Obtain a description of the power system, factors associated with the power demand and supply, and an assessment of the need for power.

- ESRP 9.2.3. For each alternative established as competitive, provide the reviewer with a description of the energy source/plant combination. This should include the basis for the staff's conclusion and sufficient design/performance data to permit the subsequent comparison of the alternative with the proposed project.

Data and Information Needs

The kinds of data and information needed will be affected by site and regional factors as they concern availability of the alternative energy sources, and the degree of detail should be modified according to the technological status of the alternatives or combinations of alternatives. If an analysis meeting the preceding criteria is not available, the following data or information should be obtained:

- For alternatives that have not yet achieved commercial acceptance, U.S. Department of Energy (DOE) research, development, and demonstration/commercialization schedules and projected capability as a source of central station power. Information on many of these technologies is available from DOE's Internet site, currently listed as http://www.doe.gov/.

- For nonrenewable fuels (coal, natural gas, and petroleum fuels), the fuel quality, availability to the applicant, rate of consumption estimates, potential environmental restrictions and impacts, and emissions and definition of U.S. national policy, if any, with respect to new uses of these fuels.

- For renewable fuels (wind, geothermal, hydroelectric, wood waste and municipal solid waste, energy crops, and solar), availability to the applicant, quantities needed, potential environmental restrictions, amount of land that would be occupied, and amount of the fuel available.

  For these alternatives, the reviewer should obtain the extent of the resource, environmental restrictions and impacts, licensing constraints, status of commercialization, and engineering problems associated with each source (from the ER and consultation with local resource agencies).

II. ACCEPTANCE CRITERIA

Acceptance criteria for the review of alternatives requiring new generating capacity are based on the relevant requirements of the following:

- 10 CFR 51.71(a) and 10 CFR 51.45(b)(3) with respect to the need to discuss alternatives to the proposed action

- 10 CFR 51, Appendix A to Subpart A, discussing alternatives to the proposed action

- 10 CFR 51.75 with respect to construction-permit contents that provide alternatives, including the proposed action, need to be part of the construction permit.

Regulatory positions and specific criteria necessary to meet the regulations as identified above are as follows:

- Regulatory Guide 4.2, Rev. 2, *Preparation of Environmental Reports for Nuclear Power Stations* (NRC 1976), with respect to the analysis of alternatives requiring new generating capacity.

Technical Rationale

The technical rationale for evaluating the applicant's alternatives requiring new generating capacity is discussed in the following paragraph:

> The consideration of alternatives is the essence of the NEPA process. The review conducted under this ESRP section contributes to the consideration of alternatives by addressing alternatives that involve the addition of power generation capacity. The results of this review are considered in the assessment of alternative energy sources and systems conducted under ESRP 9.2.3.

III. REVIEW PROCEDURES

The reviewer should review the alternative energy sources and combinations of sources available to the applicant, and categorize them as either competitive or noncompetitive with the proposed project.

(1) For competitive alternatives, the reviewer should ensure that the energy source or system meet the following criteria:

- The energy conversion technology should be developed, proven, and available in the relevant region.[a]

- The alternative energy source should provide generating capacity equivalent to the capacity need established by the reviewer of ESRP 8.4.

- The capacity should be available within the timeframe determined for the proposed project.

- Use of the energy source is in accord with national policy goals for energy use.

- Federal, State, or local regulations do not prohibit or restrict the use of the energy source.

- There are no unusual environmental impacts or exceptional costs associated with the energy source that would make it impractical.

- The reviewer should ensure that the following energy sources have been considered by the applicant:

    - wind
    - geothermal
    - petroleum liquids
    - natural gas
    - hydropower
    - advanced nuclear
    - municipal solid wastes
    - biomass
    - coal
    - photovoltaic cells
    - solar thermal power
    - wood waste
    - energy crops

(a) Current reports on specific technologies may be identified from the DOE's program offices' internet sites (http://www.doe.gov).

- advanced light-water reactor
- other advanced systems (e.g. fuel cells, synthetic fuels, etc.)

- The reviewer should ensure that all alternative energy sources available have been evaluated using the criteria listed above to determine if the alternatives can be considered competitive with the proposed project.

(2) For noncompetitive alternatives, the reviewer should ensure that the statements dismissing these alternatives are appropriately referenced, applied to the relevant regional system, and that the reasons for rejecting these alternatives have been provided.

(3) For alternative energy sources, the reviewer should evaluate the applicant's or regional authority's analysis of each energy source to determine that it describes the source plant combination in sufficient detail to enable the reviewer of ESRP 9.2.3 to compare the environmental and social costs of this alternative with the proposed project. Specific analytical procedures should depend on the alternative. The reviewer should evaluate the analysis procedure in consultation with the reviewers of ESRP 9.2.3 (for analysis requirements) and ESRP Chapter 2.0 (for environmental descriptions and socioeconomic data).

(4) For the alternatives considered viable, the reviewer should ensure that there are suitable sites for an alternative plant and should determine the general characteristics of such a site plant combination. The results of this analysis should be used by the reviewer of ESRP 9.2.3 in determining the costs (environmental, health, dollar, etc.) of the alternative and comparing them with costs of the proposed project. Based on an appropriate site (this may include the proposed nuclear plant site) and the energy sources identified, the reviewer should consider the following:

- distance from the fuel sources to the plant, probable transportation means, and mileages for each transportation means

- average daily fuel requirements based on the installed capacity need determined by the reviewer for ESRP 8.4 and the heat content

- need for fuel pretreatment (e.g., washing), if any, including the volumes of materials (water) required, the quantities of wastes produced, and means of waste disposal. Also include estimated effects of fuel source preparation on fuel characteristics, quantities of water required, and quantities of wastes produced.

- in the case of coal or other solids as the preferred alternative to the proposed project, need for combustion-product solid waste disposal, including the quantities of wastes produced and disposal methods and locations for deposition of solid waste

- need for flue-gas desulfurization, the process to be used, and (on an average daily basis), the raw material inputs and byproduct and/or waste product outputs and means of waste disposal

- average daily atmospheric releases of carbon dioxide (CO_2) and pollutants of concern regulated under the Clean Air Act (including total suspended particulates [TSP], sulfur oxides [So_x], and nitrogen oxides [NO_x].

(5) For alternatives that have been determined to be competitive, the reviewer should ensure that sufficient data are available to permit the reviewer of ESRP 9.2.3 to compare the environmental costs of these alternatives with costs of the proposed project.

(6) For each alternative established as noncompetitive, a brief statement should be prepared describing or identifying the alternative and the basis for the staff's conclusion that it was noncompetitive.

IV. EVALUATION FINDINGS

Input to the environmental impact statement (EIS) review should be directed toward accomplishing the following objectives: (1) public disclosure of the alternative energy sources considered, (2) presentation of the basis for the staff analysis, and (3) presentation of staff conclusions for each alternative energy source considered.

The depth and extent of the input to the EIS should be governed by the alternatives or combination of alternatives that are found to be economically viable. The characteristics of the alternatives should be described in sufficient detail that a decision can be reached regarding environmental impacts. The NRC staff evaluation should support concluding statements of the following type to be included in the EIS:

> The staff reviewed the available information and concluded that the issues have been covered in sufficient detail for staff analysis of alternatives requiring new generating capacity.

V. IMPLEMENTATION

The method described herein will be used by the staff in evaluating conformance with the Commission's regulations, except in those cases in which the applicant proposes an acceptable alternative for complying with specified portions of the regulations.

VI. REFERENCES

10 CFR 51, Appendix A, "Format for Presentation of Material in Environmental Impact Statements."

10 CFR 51.45, "Environmental report."

10 CFR 51.71, "Draft environmental impact statement—contents."

10 CFR 51.75, "Draft environmental impact statement—construction permit."

Clean Air Act Amendments of 1977, as amended, 41 USC 7401 et seq.

Federal Energy Regulation Commission. 1996. “Promoting Wholesale Competition Through Open-Access Nondiscriminating Transmission Services by Public Utilities,” 61 *Federal Register* 21540.

U.S. Nuclear Regulatory Commission (NRC). 1976. *Preparation of Environmental Reports for Nuclear Power Stations*. Regulatory Guide 4.2, Rev. 2, Washington, D. C.

STP Attachment 22

caller.com
CORPUS CHRISTI, TEXAS

Las Brisas proposes water pipeline

City hopes that line may help other firms

By Fanny S. Chirinos

Originally published 12:00 a.m., February 11, 2009
Updated 12:27 a.m., February 11, 2009

CORPUS CHRISTI — Las Brisas Energy Center proposes to build an eight-mile, $30 million water pipeline that would help supply the needs of the power plant and, city officials hope, other industries on the north side of the Corpus Christi Inner Harbor.

Company officials on Tuesday updated the Port of Corpus Christi on the proposed petroleum coke-fueled power plant's status and gave information on a water pipeline they propose to build and another one in which they plan to help the city.

John Upchurch, Las Brisas managing partner, said the company plans to build an eight-mile distribution line that would start at the O.N. Stevens Water Treatment Facility in Calallen and connect to the power plant on the north side of the Corpus Christi Inner Harbor. The $30 million project would provide the plant with blended, or untreated, water.

Las Brisas would use port and city right-of-way to build it and then convey it to the City of Corpus Christi for maintenance and operations, Upchurch said.

"The city wants to overbuild the line so it can support any industry on the north side of the harbor," he said.

The second pipeline would connect to the inlet of the Mary Rhodes pipeline and connect to the lower Colorado River. The 30-mile line, estimated to cost between $80 million and $100 million, would allow the city to exercise its rights to Garwood Irrigation Co. water.

The city can supply Las Brisas' water demand, about 10,000 to 15,000 acre-feet a year, and a consultant two years ago said the Garwood water would not be needed until 2030. The city uses 150,000 acre feet of its 200,000-acre-foot supply, said Gus Gonzalez, the city's director of water operations.

An acre-foot is the equivalent of about 326,000 gallons, or the volume of water sufficient to cover an acre of land to a depth of one foot. The city is paying for water rights from Garwood but doesn't have the infrastructure to move the water, the water director said.

"With Las Brisas in the picture, we're looking to speed up the process," Gonzalez said. "Las Brisas gives us the opportunity to start that project earlier."

Las Brisas, proposed by Houston-based Chase Power, is a $3 billion petroleum coke-fired facility that would gross 1,320 megawatts of power. It would create 1,300 construction jobs and 2,600 support jobs during the four years of construction.

Officials expect to create 80 to 100 permanent, full-time jobs and 150 to 175 support jobs and pay $400 million to $500 million in tax revenues during the first 10 years of operations. Officials applied for an air permit to the Texas Commission on Environmental Quality in May.

A contested hearing regarding that air permit is scheduled at 10 a.m. Feb. 17 in the sixth floor conference room at City Hall, 1201 Leopard St.

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CHAPTER 3.0: IDENTIFICATION OF CURRENTLY AVAILABLE WATER SUPPLIES

A key task in the preparation of the Lower Colorado Regional Water Plan (LCRWP) is to determine the current available water supplies within the region. This information, when compared to the population and water demand projections, is critical in projecting water supply shortfalls and surpluses for the region, including the amount of shortfall, when a shortfall is expected to occur, and the county in which the shortfall is expected.

As presented in Chapter 2, the expected water demand in the Lower Colorado Regional Water Planning Area (LCRWPA) is projected to increase by approximately 23 percent while the population is projected to more than double over the next 60 years. Therefore, the need to accurately identify available water supplies is a critical component of developing the regional plan.

The following sections of the chapter describe the methodologies utilized in developing estimates of currently available water supplies for the LCRWPA. This chapter also presents regional water supplies by county, wholesale water providers of municipal water, and the six Texas Water Development Board (TWDB) specified water-use categories.

3.1 TWDB GUIDELINES FOR REVISIONS TO WATER SUPPLIES

The Texas Water Development Board (TWDB) has promulgated rules for regional planning and has provided specific guidance to Regional Water Planning Groups (RWPGs) concerning the development of estimates of currently available water supplies. The guidance clearly indicates that the estimates of currently available water supplies shall reflect water that is reliably available to the area during a repeat of the "drought-of-record" (DOR) conditions. The specific methods used in determining the amount of currently available water vary depending upon whether it is a groundwater or surface water resource. A summary of TWDB guidelines and methods for estimating currently available water supply is presented below.

3.2 AVAILABLE WATER SOURCES TO THE LCRWPA

In accordance with the TWDB guidelines, five basic types of water supply exist within the LCRWPA. The types are as follows:

- Surface water supplies
- Groundwater supplies
- Supplies available through contractual arrangements
- Supplies available through the operation of a system of reservoirs or other supplies
- Reclaimed water

Since supplies available through the last three categories originated from either surface or groundwater sources, all available water supplies will be discussed in terms of being either of surface water origin or groundwater origin. The following sections present information concerning the available supply of water within the LCRWPA. That is to say, water that is physically present within the LCRWPA, whether it is present due to natural circumstances, or it is present as a result of facilities constructed by one or more water users within the LCRWPA.

3.2.1 Surface Water Availability

Surface water sources include any water resource where water is obtained directly from a surface water body. This would include rivers, streams, creeks, lakes, ponds, and tanks. In the State of Texas, all waters contained in a watercourse (rivers, natural streams, and lakes, and the storm water, flood water, and rainwater of every river, natural stream, canyon, ravine, depression, and watershed) are waters of the State and thus belong to the State. The State grants individuals, municipalities, water suppliers, and industries the right to divert and use this water through water rights permits. Water rights are considered property rights and can be bought, sold, or transferred with state approval. These permits are issued based on the concept of prior appropriation, or "first-in-time, first-in-right." Water rights issued by the State generally fall into two major categories:

- Run-of-River (ROR) Rights – Allow diversions of water directly from a water body as long as there is water in the stream and that water is not needed to meet a senior downstream water right. ROR rights are greatly impacted by drought conditions, particularly in the upper portions of a river basin.

- Stored Water Rights – Allow the impoundment of water by a permittee in a reservoir. Water can be held for storage as long as the inflow is not needed to meet a senior downstream water right. Water stored in the reservoir can be withdrawn by the permittee at a later date to meet water demands. The storage of water in a reservoir gives the permittee a buffer against drought conditions.

A list of active water rights within the LCRWPA is contained in *Appendix 3A*.

In addition to the water rights permits issued by the State, individual landowners may use state waters without a specific permit for certain types of use. The most common of these uses is domestic and livestock use. Landowners are also allowed to construct impoundments on their own property with up to 200 acre-feet (ac-ft) of storage for domestic and livestock or certain wildlife management purposes. These types of water sources are generally referred to as "Local Supply Sources." Many individuals with land along a river or stream that still have an old riparian right can also divert a reasonable amount of water for domestic and livestock uses without a permit.

Water availability in Region K will be determined for the purposes of regional planning as prescribed by the TWDB water planning guidelines. The TWDB guidance requires that the amount of surface water available from each source be determined with the following assumptions:

- Water availability will be estimated based on a "firm yield" analysis. For a reservoir system, this analysis would produce the average annual withdrawals available during a repeat of the drought of record considering the long-term storage capabilities, projected inflows, and evaporation. For water rights based solely on run-of-river, the drought of record corresponds to the driest period on record. Without available storage, water is no longer available if the river goes dry. In addition, a run-of-river right may not be able to divert even if there is water in the river or stream due to the constraints of the prior appropriation system or environmental flow limitations.

- Water availability will be based on the assumption that all senior water rights in the basin are being fully utilized. That is, water user groups cannot depend on "borrowing" water from unused water rights.

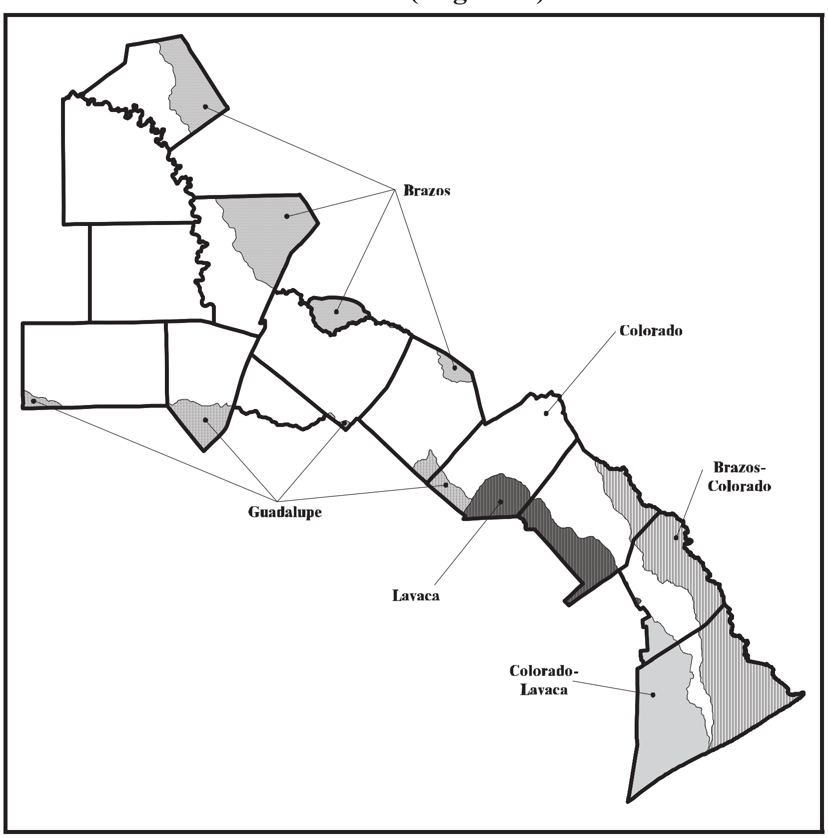
- Water supply is based on the infrastructure that is in place. For example, water would not be considered to be a supply from a reservoir if a user still needed to construct the water intake and pipeline to convey the water from the reservoir to the area of need.

It should be noted that state directives (summarized above) to regional water planners on how they are to determine water availability in meeting future water supply needs may impose unrealistic assumptions on how water is actually used or will be used over the planning period. This methodology requires local water planners to assume that every water right holder will simultaneously divert and totally consume the water up to their full authorizations. These directives have the potential to over estimate water shortages.

Although "worst case" conservative assumptions may be appropriate to avoid the theoretical "over permitting" of water, it may be unrealistic to use this methodology alone for planning purposes. Rather local and regional planners should be allowed, and are to some extent by the existing process, to bring their knowledge, experience, and common sense to the "planning effort" to determine realistic water availability assumptions, something Senate Bill 1 was intended to provide by establishing a "bottom-up" approach to replace the previous "top-down" state planning approach.

The LCRWPA traverses six different river basins, including the Brazos, Brazos-Colorado Coastal, Colorado, Colorado-Lavaca Coastal, Lavaca, and Guadalupe River Basins. *Figure 3.1* illustrates the location of each of these basins. The following sections discuss the available water sources in each river basin within the LCRWPA.

Figure 3.1: River Basins Within the LCRWPA (Region K)



3.2.1.1 Colorado River Basin

The majority of the LCRWPA is contained in the Colorado River Basin. The primary sources of water within this basin are the Highland Lakes and run-of-river water from the Colorado River. However, several water user groups obtain water from tributaries or off-channel ponds.

The availability (firm supplies available during a drought of record) of existing surface water supplies in the Colorado River Basin, specifically major run-of-river rights and reservoirs firm yields, were calculated using the Texas Commission on Environmental Quality's (TCEQ) Colorado River Basin Water Availability Model (WAM), dated November 2004. The results were viewed using the July 2004 version of the WRAP modeling program, created by Dr. Ralph Wurbs with Texas A&M University.

The Run 3 version of the model was used, which assumes full utilization of all water rights. Full utilization is defined as 100 percent of the authorized diversion with 100 percent reuse of return flows, i.e. no return flow to the river. This is the most conservative version of the model and will provide the most conservative results. It is important to note that the LCRA Water Management Plan does take return flows into consideration.

The WAM Run 3 was used in its existing state to determine the 2000 water availability and was used with adjusted reservoir area-capacity curves to project the availability for 2010 through 2060. The reservoir area-capacity information was obtained from the LCRA, Freese and Nichols, Inc. (Region F consultant) and by using the December 2001 *Water Availability Modeling for the Colorado/Brazos-Colorado Basin Modeling Report* prepared by R.J. Brandes Company.

The results showing the availability of firm water supplies and the need for firm water backup for some ROR rights are significantly different from the initial regional water plan. The most significant differences between the LCRA RESPONSE Model (which was utilized for the 2001 Plan and developed, in part, from data contained in the Texas Water Commission's legacy model, LP-60) and the WAM are:

1. The availability of inflows above Ivie Reservoir in the WAM

2. The inclusion of the priority of the storage right as well as the diversion right for the Highland Lakes in the WAM

3. Differences in the underlying hydrology (naturalized flow) between the models

Other differences are outlined in *Appendix 3B*.

In addition to the standard WAM Run 3 described above, the Regional Planning Group also authorized the development of an alternative WAM run which will be referred to as the "No Call" WAM Run 3. The No Call WAM was developed as a result of a request from the Region F Planning Group. The November 2004 WAM indicated a lack of water available on a firm yield basis in a number of Region F's reservoirs as compared to the last planning cycle. In addition, there was some similarity between the No Call WAM and the current operations of the river system. The No Call WAM and a more definitive explanation of the reasons for its use are presented in Section 3.2.1.2, and in *Appendix 3C*. The Colorado River surface water availability amounts developed through the No Call WAM are the amounts used in developing this plan. These availability numbers are presented starting on page 3-15.

3.2.1.1.1 Highland Lakes System

The Highland Lakes System is composed of two major water storage reservoirs – Lakes Buchanan and Travis. These lakes are owned and operated by the LCRA. In addition, the system contains three intermediary lakes owned and operated by the LCRA – Inks Lake, Lake LBJ, and Lake Marble Falls. Lake Austin, the last in the Highland Lakes System, is owned by the City of Austin and is operated by the LCRA through an agreement.

The LCRA operates the Highland Lakes as a system to provide a reliable source of water to downstream customers. The LCRA developed a "Water Management Plan for the Lower Colorado River Basin" in response to requirements contained in a final order of adjudication of water rights to the LCRA for the Highland Lakes. The Water Management Plan (WMP) was originally adopted in 1989 and has been amended several times, most recently in March 1999, and proposed amendments to the WMP submitted in May 2003 are currently undergoing TCEQ review. As part of the original WMP, LCRA determined the combined firm yield of Lakes Buchanan and Travis based on a detailed analysis of the water availability for Lakes Buchanan and Travis during a repeat of the drought of record. The WMP also contains a management strategy for meeting the 10-year projected demands of its firm municipal and industrial customers, while continuing to provide water for environmental needs and agricultural purposes, largely on an interruptible basis. The LCRA's WMP determines the amount of interruptible water supply that can be made available while continuing to ensure the availability of water for firm demands in a repeat of a drought of records using a system of curtailment triggers that are linked to actual water in storage on January 1 of each year. The interruptible supply is generally comprised of uncommitted firm supply, committed firm supply that is not projected to be used in the ten year planning period covered by the plan, and flood flows. As firm commitments and demands for water under those commitments increase over time, interruptible supplies must be reduced more often even at higher storage levels to ensure the availability of water to firm customers in a DOR. The November 2004 TCEQ Colorado Basin WAM model was developed using the LCRA 1999 WMP, and therefore that is the version of the WMP that was used for the development of water availability in this regional water plan.

The firm yield of the Highland Lakes System was determined by using the Colorado River Basin WAM and adding up the various components of the Highland Lakes System. The model, which was developed by TCEQ with help from the LCRA to include their Water Management Plan, took the following factors into account:

- Water rights were protected based on prior appropriation doctrine
- The hydrologic conditions in the 1940-1998 period are repeated
- Downstream, senior water rights are being fully utilized during this period. The water rights in the Lower Colorado Region are included in *Appendix 3A*
- The LCRA cannot impose its priority rights for Lakes Buchanan and Travis against any upstream, junior water right with a priority date senior to November 1, 1987, so long as interruptible supplies are not curtailed
- Historical net evaporation rates for the period of 1940 through 1998
- Downstream water demands were assumed to be met with inflows to the river below the Highland Lakes, to the extent possible

- The firm yield of the Highland Lakes is reduced by a certain amount due to the agreement with the Colorado River Municipal Water District and the operation of the O.H. Ivie Reservoir.

The method (2004 WAM) used to determine the firm yield of Lakes Buchanan and Travis in this plan differs from the method used to calculate the combined firm yield approved by the Texas Water Commission as part of LCRA's WMP in 1989 in at least three ways. First, the 1989 calculation imposed no curtailment triggers for interruptible supply whereas the 2004 WAM incorporated these triggers. Similarly, the second difference is that criteria for meeting certain environmental flow needs are embedded in the 2004 WAM whereas the 1989 calculations contained no conditions allocating flows to environmental needs or any other particular demand. Third, the 1989 calculation assumed a return flow factor of about 55 percent for the City of Austin's municipal water right, backed up by stored water from LCRA, whereas the 2004 WAM assumes zero return flows from water diverted by Austin.

Table 3.1 Components of the Highland Lakes System Firm Yield

Entity or Use	Firm Yield Commitment, Ac-Ft/Yr [1]						
	2000	**2010**	**2020**	**2030**	**2040**	**2050**	**2060**
O.H. Ivie Reservoir Yield Reduction	85,700	82,100	78,700	76,100	74,000	73,500	77,500
Backup of City of Austin Water Rights	65,731	65,498	65,499	65,501	65,309	65,658	65,592
Highland Lakes Contracts	85,789	85,789	85,789	85,789	85,789	85,789	85,789
LCRA Cooling Water	64,551	64,551	64,551	64,551	64,551	64,551	64,551
South Texas Nuclear Project	45,316	43,530	43,529	43,528	43,535	43,537	43,537
Instream Flow Requirements	13,141	13,138	13,133	13,114	16,081	16,053	16,031
Bay and Estuary Flow Requirements	6,416	6,408	6,406	6,404	6,682	8,117	8,115
Additional Highland Lakes Contracts	62,282	62,282	62,282	62,282	62,282	62,282	62,282
Total System Commitment	428,926	423,296	419,889	417,269	418,229	419,487	423,397
Uncommitted System Yield	92,511	78,111	74,611	70,211	65,811	60,911	55,711
Total System Yield	**521,437**	**501,407**	**494,500**	**487,480**	**484,040**	**480,398**	**479,108**

Data Source: Colorado WAM provided by TCEQ, November 2004, Run 3. WRAP modeling program provided by Dr. Ralph Wurbs, Texas A&M University, July 2004 version.

[1] A description of this system and an explanation of all of the components is provided in Section 3.2.1.1.1. Using the 1999 WMP triggers for curtailment, interruptible supplies are also still available.

Table 3.1 above shows the components that make up the firm yield of the Highland Lakes System. The November 2004 Run 3 version of the Colorado River Basin WAM was used to determine the values in the table. The results were viewed using the July 2004 version of the WRAP modeling program. The firm yields were calculated for the 10-year DOR period (May 1947 to April 1957), which was identified as the most severe drought period since 1898. The firm yield commitments are releases from system storage; they do not consist of run-of-river water. The following describes the methods used to determine the values in *Table 3.1*.

O.H. Ivie Reservoir Yield Reduction

The end-of-period (EOP) content of the Travis/Buchanan reservoirs was looked at to determine which month and year during the simulation the reservoirs went dry. The portion of the WAM that allows water at Lake Buchanan's priority date to be captured by Ivie Reservoir to allow a firm diversion of 113,000 ac-ft/yr was removed, and the LCRA remaining firm yield authorized diversion (61405482001C) was increased until the reservoirs were again dry or nearly dry.[1] The difference between the new remaining firm yield authorized diversion (61405482001C) and the original was calculated. This difference is the effect that Ivie has on the Highland Lakes system.

Backup of City of Austin Water Rights
The three LCRA backup amounts for the City of Austin municipal water rights were summed. These water rights are 61405471005RMBU (39,208 ac-ft), 61405471005LMBU (10,803 ac-ft), and 61405489003MBU (15,720 ac-ft for the year 2000).

Highland Lakes Contracts
The amount listed in the 1999 LCRA Water Management Plan was used.

LCRA Cooling Water
The availability for water rights 61405480001 (15,700 ac-ft), 61405473001 (10,750 ac-ft), and 61405474001 (38,101 ac-ft) was summed.

South Texas Nuclear Project
This is water right 61405437001BU (45,316 ac-ft).

Instream Flow Requirements
In 1992, LCRA, working with the state natural resource agencies, completed an instream flow needs study. The study was later approved by the Texas Water Commission, predecessor agency to the TCEQ, as incorporated into LCRA's Water Management Plan. The results of that study included two sets of instream flow needs: Critical and Target instream flow needs. The quantity of water committed by the LCRA Highland Lakes System under the Water Management Plan to instream flows consists of (1) the passage of inflows to meet the Target and Critical instream flow criteria that might otherwise be available to store in the Highland lakes; and, (2) the release of stored water to help meet the Critical instream flow criteria. In order to determine the quantity of inflow the LCRA Highland Lakes System bypassed for instream flows in the WAM, the quantity of inflow available to the LCRA's Highland Lakes System before and after an environmental need is engaged, is computed and the inflow reduction to the LCRA Highland Lakes System due to each environmental need is attributed as water bypassed for each environmental need. To determine the quantity of additional stored water released for critical instream flows, the exact quantity of water released from the LCRA Highland Lakes System Storage to help meet each environmental need is extracted from the WAM output and attributed as stored water released for each environmental need. Once all of these components have been extracted and tabulated, the total quantity of water dedicated to instream flows is determined.

The 1999 LCRA Water Management Plan states:
"Total commitments of the Combined Firm Yield from the Highland Lakes for instream flow maintenance will be an average of 12,860 acre-feet per year, with a maximum of 36,720 acre-feet in any one year; 58,700 acre-feet in any two consecutive years; 76,800 acre-feet in any three or four consecutive years; 106,100 acre-feet in any five consecutive years and 128,600 acre-feet in any six to ten consecutive years."

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[1] The November 2004 WAM does not currently allow a firm diversion of 113,000 ac-ft/yr. This is a remaining technical issue to be addressed.

Bay and Estuary Flow Requirements
This amount was the DOR average of BEC-IN (Bay and Estuary Critical – In) minus BEC-OT (Bay and Estuary Critical – Out) from the model output (6,416 ac-ft in the year 2000 scenario).

Critical inflow is the amount of water needed to provide a fishery sanctuary habitat near the mouth of the Colorado River during times of drought. From this sanctuary, fish, shellfish and oysters could be expected to recover and repopulate the bay when more normal weather conditions return.

The 1999 LCRA Water Management Plan states:
"Total commitments of the Combined Firm Yield from the Highland Lakes for bays and estuaries (estuarine inflows) will be an average of 3,090 acre-feet per year, with a maximum of 11,200 acre-feet in any one year; 19,700 in any two consecutive years; 24,200 acre-feet in any three or four consecutive years; 28,200 acre-feet in any five consecutive years and 30,900 acre-feet in any 6 to 10 consecutive years.

The total firm stored water commitment for both purposes (instream flow and bays and estuaries) will be an average of 15,950 acre-feet per year. Estimated interruptible stored water supplied during the critical drought for both purposes will be an additional 40,060 acre-feet per year."

Additional Highland Lakes Contracts
This amount includes contracts LCRA is maintaining that were not included in the 1999 Water Management Plan that have separate water rights associated with them. The components are the Cities of Cedar Park (18,000 ac-ft), Leander (6,400 ac-ft), Lometa (882 ac-ft), Pflugerville (12,000 ac-ft), and the Brazos River Authority (25,000 ac-ft).

Uncommitted System Yield
This was determined by subtracting the Highland Lakes Contracts amount (85,789 ac-ft) from the LCRA remaining firm yield (61405482001C) in the WAM. This amount includes any additional firm commitments LCRA has made since the 1999 WMP was approved that do not have separate water rights associated with them.

Highland Lakes
The total system yield decreases over time due to sedimentation of the reservoirs. The Highland Lakes firm yield is equal to the Total System Yield minus the O.H. Ivie Reservoir commitment, and is shown in *Table 3.2*.

3.2.1.1.2 Reservoirs

The estimated firm yields for all reservoirs within the Colorado River Basin are presented in *Table 3.2*.

Table 3.2 Reservoir Yields in the Colorado Basin (ac-ft/yr)

Reservoir Name	Firm Yield [1]						
	2000	2010	2020	2030	2040	2050	2060
Highland Lakes	**435,737**	**419,307**	**415,800**	**411,380**	**410,040**	**406,898**	**401,608**
City of Goldthwaite	125	125	125	125	125	125	125
City of Llano	99	99	99	99	99	99	99
Walter E. Long (Decker Lake)	0	0	0	0	0	0	0
Lake Bastrop	0	0	0	0	0	0	0
Lake Fayette	0	0	0	0	0	0	0
City of Lometa	0	0	0	0	0	0	0
STP Reservoir	0	0	0	0	0	0	0
Minor Reservoir Subtotal	**224**	**224**	**224**	**224**	**224**	**224**	**224**
TOTAL	**435,961**	**419,531**	**416,024**	**411,604**	**410,264**	**407,122**	**401,832**

Data Source: Colorado WAM provided by TCEQ, November 2004, Run 3. WRAP modeling program provided by Dr. Ralph Wurbs, Texas A&M University, July 2004 version.

[1] A description of each minor reservoir and an explanation of the firm yield is provided in Section 3.2.1.1.2. The Highland Lakes are discussed in Section 3.2.1.1.1.

The Highland Lakes firm yield is discussed in detail in Section 3.2.1.1.1. Several smaller reservoirs in the LCRWPA are also located within the Colorado River Basin. Estimates for the firm yield of these reservoirs are based on the TCEQ WAM Run 3 modeling and a detailed discussion is provided below.

- The **City of Goldthwaite** owns and operates a two-reservoir system as part of its water supply facilities. The reservoirs include a small reservoir with a capacity of 40 ac-ft adjacent to the river and a larger reservoir with a capacity of 200 ac-ft, which is located off-channel. The city pumps water from the Colorado River into the smaller reservoir and then pumps it into the larger reservoir, from which water is drawn for treatment. The size of the reservoirs are relatively small in comparison to the city's water demand, which is projected to decline from approximately 580 ac-ft in the year 2000 scenario to 565 ac-ft in the year 2060. Based on the limited storage available, the firm yields of the reservoirs are dependent upon continued river flows throughout the year. It is estimated that the available storage would be depleted within four months once the river ceases flowing. Based on the TCEQ WAM Run 3, it was determined that the Goldthwaite reservoir system has a firm yield of 125 ac-ft/yr (water rights 61402553401, 61402553402, and 61402553001).

- The **City of Llano** owns and operates two reservoirs on the Llano River: City Lake and City Park Lake, both of which are small channel dams. The two reservoirs were estimated to have a combined capacity of 503 ac-ft in 1988. This is significantly less than the original design capacity of 700 ac-ft. The decreased capacity is due to sedimentation rates in the two reservoirs. The firm yield estimated by the TCEQ WAM was 99 ac-ft/yr (water rights 61401650001 and 61401650002).

- **Lake Walter E. Long (Decker Lake)** is owned and operated by the City of Austin. The lake is formed by a dam on Decker Creek, which is a tributary to the Colorado River in Travis County. The City of Austin uses Decker to supply cooling water for an electrical generating plant. The City of

Austin supplements the water supply to Decker by pumping water from the Colorado River based on run-of-river rights and a water supply contract with LCRA for stored water from the Highland Lakes. Therefore, because the water from Decker Lake has already been accounted for in run-of-river and LCRA backup amounts, the firm yield of the lake itself due to the TCEQ WAM is considered 0 ac-ft/yr.

- **Lake Bastrop** is owned and operated by the LCRA. The lake is formed by a dam on Spicer Creek, which is a tributary to Piney Creek and the Colorado River in Bastrop County. The LCRA uses water from Lake Bastrop for cooling purposes at its Sam Gideon Power Generating Station. The LCRA supplements the water supply at this lake by pumping water into the lake from the Colorado River. The water pumped into the lake is stored water from the Highland Lakes. Therefore, because the water from Lake Bastrop has already been accounted for in run-of-river and LCRA backup amounts, the firm yield of the lake itself due to the TCEQ WAM is considered 0 ac-ft/yr.

- **Lake Fayette** is owned and operated by the LCRA. The lake is formed by a dam on Cedar Creek, which is a tributary to the Colorado River in Fayette County. The LCRA uses water from Lake Fayette for cooling purposes at the Fayette Power Project. The LCRA supplements the water supply at this lake by pumping water into the reservoir from the Colorado River. A portion of the water pumped is run-of-river water rights held by the City of Austin, which is co-owner in the Fayette Power Project. The remainder of the water pumped into the reservoir is stored water from the Highland Lakes. Therefore, because the water from Lake Fayette has already been accounted for in run-of-river and LCRA backup amounts, the firm yield of the lake itself due to the TCEQ WAM is considered 0 ac-ft/yr.

- **Lometa Reservoir** is owned and operated by the LCRA. The reservoir is formed by a dam on Salt Creek, which is a tributary to the Colorado River in Lampasas County. The LCRA uses water from Lometa Reservoir for municipal purposes within the service area of the City of Lometa. The reservoir has a normal maximum operating capacity of 554.6 ac-ft. A maximum of 882 ac-ft of water is available for diversion from the Colorado River, including 476 ac-ft for municipal demands and 406 ac-ft to off set evaporative losses. Because this amount is included as part of the Highland Lakes firm yield, the reported firm yield of the Lometa Reservoir is 0 ac-ft/yr.

- **South Texas Project Reservoir**: The Main Cooling Reservoir associated with the South Texas Project Electric Generating Station is a 7,000-acre (surface area) off-channel reservoir located in Matagorda County. At the maximum design operating level, the reservoir has a capacity of 202,600 ac-ft, or 9.6 percent of the total capacity of Lakes Travis and Buchanan as stated in the LCRA Water Management Plan. The firm yield from the TCEQ WAM is considered to be 0 ac-ft/yr since the reservoir firm yield is supplied by the STP run-of-river right (STP Nuclear Operating Co. et al.) and LCRA stored water from Lakes Buchanan and Travis, and the amount of water from the run-of-river right and LCRA's Highland Lakes has already been included in the water availability analysis for Region K (refer to *Tables 3.1* and *3.3*). If both the run-of-river right and the reservoir firm yield were included, then the water would be double counted since the water available to the reservoir is based on the diversions from the river.

  Reservoir water is withdrawn from the Colorado River adjacent to the site. Pumping from the river is intermittent, and this diversion normally occurs during periods of high river flow. The reservoir design incorporates storage to account for periods during which river water is unavailable for the reservoir in order to support operation through a repeat of the drought of record.

3.2.1.1.3 Run-of-River Water

Historically, the State of Texas has granted run-of-river rights through an adjudication process that considered historical uses. As a result, some run-of-river rights may have been granted for more water than is available in a river during drought conditions. The use of water during drought conditions is controlled by the priority system, with the oldest water rights having first call on whatever water is in the river. The TCEQ Colorado River Basin WAM was developed to simulate the amount of water available in the Colorado River under the basin water management scenarios. Major factors used to calculate available water include:

- Senior downstream water rights are assumed to be fully utilized
- Stored waters are released to the river based on the drought conditions
- Inflows to the Highland Lakes are passed through the lakes to the extent that the water is needed to satisfy senior water rights downstream.

The results of this analysis for major run-of-river rights holders are presented in *Table 3.3*. The water availability presented in the table for most of the major run-of-river rights is based on the amount of run-of-river water that would be available during the driest year of the DOR (1952 in the WAM). The water availability for the City of Austin and STNP water rights is based on the average water availability during the 10-year DOR period. This average availability was used since the City of Austin has contracted with LCRA to supply stored water to firm up its water rights during drought conditions. The STNP has also contracted for backup from LCRA, in addition to having a reservoir that allows for potential storage of water over the DOR period instead of having to use all of the water that is received in a particular year.

Table 3.3 Major Run-of-the-River Rights in the Colorado Basin (ac-ft/yr)

Water Right ID Numbers	Water Rights Holder	Maximum Permitted Diversion	Priority Date	Water Availability During Drought of Record [1]	
				2000	2060
61405434201RR	LCRA - Garwood	133,000	Nov 1, 1900	133,000	133,000
61405475001LRRS	LCRA - Lakeside #1 [2]	52,500	Jan 4, 1901	16,908	16,908
61405475001LRRL			Jun 29, 1913	4,075	4,075
61405475001LRRR			Mar 8, 1938	0	0
61405475001LRRJ		78,750	Nov 1, 1987	4,977	4,977
61405476003RRS	LCRA - Gulf Coast [2]	228,570	Dec 1, 1900	42,140	42,140
61405476003RRL			Jun 29, 1913	77,428	77,428
61405476003RRR			Mar 8, 1938	0	0
61405476003RRJ		33,930	Nov 1, 1987	2,952	2,952
61405477001RR	LCRA - Pierce Ranch [2]	55,000	Sep 1, 1907	20,589	20,589
61405477001RRL			Jun 29, 1913	1,648	1,648
61405477001RRR			Mar 8, 1938	0	0
61405475001WRR	LCRA - Lakeside #2 [2]	55,000	Sep 2, 1907	21,923	21,923
61405475001WRRL			Jun 29, 1913	1,648	1,648
61405475001RRRR			Mar 8, 1938	0	0
61405471005SMRR	City of Austin - (mun.) [3]	250,000	Jun 30, 1913	159,503	159,503
61405471005SBU	City of Austin - (mun.) [3]		Jun 30, 1913	51,289	51,289
61405471005LMRR	City of Austin - (mun.) [3]	21,403	Jun 27, 1914	10,600	10,600
61405471001P	City of Austin - (stm.)	24,000	Jun 27, 1914	14,894	14,894
61405471002P	City of Austin - (stm.)		Jun 27, 1914	1,901	1,901
61405489003M	City of Austin - (mun.) [3]	20,300	Aug 20, 1945	4,580	4,719
61405489003P	City of Austin - (stm.)	16,156	Aug 20, 1945	0	0
61405489003PBU	City of Austin - (stm.)		Aug 20, 1945	1,346	0
61405437001RIV	STP Nuclear Operating Co. et al. [3]	102,000	Jun 10, 1974	42,291	43,736
61405434102	City of Corpus Christi	35,000	Nov 2, 1900	31,579	31,579
Totals		**1,105,609**		**645,271**	**645,509**

Data Source: Colorado WAM provided by TCEQ, November 2004, Run 3. WRAP modeling program provided by Dr. Ralph Wurbs, Texas A&M University, July 2004 version.

[1] Downstream water availability reflects minimum year during the drought unless otherwise noted and does not include return flows. An explanation of the firm yield calculations in provided in Section 3.2.1.1.3.

[2] The low reliability of the LCRA irrigation rights is due to a subordination agreement with the City of Austin.

[3] The water availability was averaged over the DOR.

Table 3.3 above shows the water availability during the DOR for the major run-of-river rights. The November 2004 Run 3 version of the Colorado River Basin WAM was used to determine the values in the table. The following describes the methods used to determine the values in *Table 3.3*.

Irrigators

Garwood was 100 percent reliable for its full authorized diversion amount of 133,000 ac-ft.

Lakeside #1, Gulf Coast, Pierce Ranch, and Lakeside #2 each have several water rights, both run-of-river and backup. The run-of-river rights are listed in *Table 3.3*. The run-of-river water rights were summed for each irrigator to determine which year in the model had the minimum total diversion. The water right amounts for that year are listed in the table.

City of Austin
The City of Austin has four municipal water rights shown in the table. These are 61405471005SMRR, 61405471005SBU, 61405471005LMRR, and 61405489003M. Because these water rights are backed up by LCRA each year, an average during the DOR was used.

The City of Austin has steam-electric water rights as shown in the table. These are 61405471001P, 61405471002P, and 61405489003P (61405489003PBU). The water availability for these rights was determined by using the minimum amount of water available in any year during the DOR.

STP Nuclear Operating Company et al.
The run-of-river water right, 61405437001RIV, was determined by taking the average over the DOR period. This was done because there is a contract for backup from LCRA, and there is a reservoir that allows for storage of water over the DOR period, rather than having to use the entire amount of water received in a particular year. It should be noted that in any year, the sum of the run-of-river amount plus the amount of backup provided by LCRA (61405437001BU in *Table 3.1*) will never be more than 102,000 ac-ft, but can be less. The STNP diversion point is within the tidal reaches of the Gulf of Mexico. Required diversions at low flow rates during the DOR period will have a negative effect on the water quality diverted at this point.

Corpus Christi
The water availability for this run-of-river water right was determined by using the minimum amount of water available in any year during the DOR.

3.2.1.1.4 Local Surface Water Sources

The final category of available surface water is local supply sources. This category includes small diversions from the river or tributaries to the river, as well as stock ponds that have captured diffuse surface water located on individual's property. Information concerning these sources is limited. As a result, the information available from the TWDB developed during the first planning cycle was used as an initial estimate of the water availability. However, in several instances the availability numbers were increased to match the projected demands with the assumption that the supply and demand for local water will be self-limiting. The results of this process are presented in *Table 3.4* and are organized by county. These numbers were developed for the 2001 Region K Plan and since better information has not become available they have remained unchanged.

Table 3.4 Other Surface Water Sources in the Colorado Basin (ac-ft/yr)

Local Supply Source Name	Year 2000	Year 2010	Year 2020	Year 2030	Year 2040	Year 2050	Year 2060
Livestock - basinwide	6,262	6,262	6,262	6,262	6,262	6,262	6,262
Other - basinwide	27,642	19,282	20,890	22,717	24,883	27,470	27,470
Irrig. - Bastrop Co.	786	786	786	786	786	786	786
Irrig. - Blanco Co.	67	67	67	67	67	67	67
Irrig. - Burnet Co.	276	276	276	276	276	276	276
Irrig. - Colorado Co.	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Irrig. - Fayette Co.	534	534	534	534	534	534	534
Irrig. - Gillespie Co.	880	880	880	880	880	880	880
Irrig. - Hays Co.	41	41	41	41	41	41	41
Irrig. - Llano Co.	440	440	440	440	440	440	440
Irrig. - Matagorda Co.	900	900	900	900	900	900	900
Irrig. - Mills Co.	2,378	2,378	2,378	2,378	2,378	2,378	2,378
Irrig. - San Saba Co.	8,800	8,800	8,800	8,800	8,800	8,800	8,800
Irrig. - Travis Co.	880	880	880	880	880	880	880
Irrig. - Wharton Co.	7,650	7,650	7,650	7,650	7,650	7,650	7,650
Totals	**60,536**	**52,176**	**53,784**	**55,611**	**57,777**	**60,364**	**60,364**

Note: All of the sources listed in the table above are Local Supply Sources, which were determined in the 2001 Plan.

It was assumed that the 2060 supplies were equal to the 2050 supplies due to the lack of better information or tools to determine availability in 2060.

STP Attachment 24

caller.com
CORPUS CHRISTI, TEXAS

Corpus Christi council gives city manager authority to sell water to Las Brisas Energy Center

Escobar has final authority in negotiations with group seeking to build $3 billion plant

By Denise Malan

Originally published 07:13 p.m., May 11, 2010
Updated 05:26 a.m., May 12, 2010

CORPUS CHRISTI — The City Council gave the city manager final authority in negotiations to provide water to Las Brisas Energy Center, a proposed $3 billion plant that would add as much as 12 percent to the city's water demand.

The 5-2 decision came after three hours of discussion Tuesday in which 45 residents addressed the council. The standing-room-only crowd was split with some wearing pro- or anti-Las Brisas T-shirts and buttons.

"We're very pleased," Las Brisas managing partner Kathleen Smith said. "I think I'll just leave it at that."

The contract will not have to come back to the council for approval. Councilman John Marez's motion for the water contract come back to council for approval, rather than be executed by City Manager Angel Escobar, failed by a 4-3 vote.

Las Brisas proposes to generate power from petroleum coke, a leftover from oil refining. It has been hailed as the largest private investment in Nueces County history and attacked as a threat to the environment.

Some prominent local residents spoke on both sides of the debate. Former Port of Corpus Christi Commissioner Bernard Paulson was for; former state Sen. Carlos Truan was against.

Proponents emphasized the plant's boon to the local job market and tax rolls as well as lower electricity and water rates expected with construction of the plant. Opponents said the city should not support a major polluter and cannot afford to sell so much water.

Mayor Joe Adame and council members John Marez, Kevin Keischnick, Chris Adler and Mark Scott voted for negotiations. Council members Nelda Martinez and Priscilla Leal voted against.

Those who voted for the plant said they trust the Texas Commission on Environmental Quality to vet the plant for environmental and health issues.

Marez said the decision was the most critical since he was elected in 2006.

"I have faith that if this is not a good plant for Corpus Christi that it will fail," he said. "We cannot just stop the process here. We have to let this project go before the TCEQ and defend the project on its merits."

Martinez had originally supported the project but voted no after researching the project, she said.

"I have learned a great deal and have learned Las Brisas would have an irreparable harm on our community, not only on its health but on its economy," Martinez said.

Councilmen Brent Chesney and Larry Elizondo abstained from discussions. Chesney said he found out Monday his employer, First American Corp., is involved with insurance for Chase Power, the parent company of Las Brisas. The local title branch of First American is not involved, but Chesney is a shareholder in the parent corporation. Elizondo abstained because he works for Citgo, which would supply coke to Las Brisas.

Three opponents asked Councilman Mark Scott to recuse himself because his wife Carol Scott previously worked on public relations for the plant. The councilman said he sought an opinion from the city's legal department that cleared him to participate.

The contract would provide the proposed power plant with blended water, or water that has been partially treated to settle out some sediments.

The council also voted 5-2 to develop a blended water rate, a necessary move because the city does not currently sell blended water.

The plant would use between 5 billion and 7 billion gallons of water per year, adding 9 percent to 12 percent to current usage.

Dr. Wes Stafford told the council Las Brisas is the first project the Nueces County Medical Society has opposed in its 150-year history.

"It's not good for our economy if we spend more taking care of sick people because it's here than we make in tax revenues," Stafford said.

Members of the Clean Economy Coalition, League of Women Voters, League of United Latin American Citizens Council No. 1, Coastal Cardiology Association and former

Councilman Michael McCutchon, an anesthesiologist, also spoke against the plant.

Realtor Cliff Atnip told the council members they were elected to help the city move forward.

"We are definitely 100 percent behind growth and moving forward," he said. "All growth has a cost. We've already heard that from our doctors. But if we don't grow, we die."

Paulson said the city secured water rights to the Lower Colorado River years ago to help attract new industry.

"That certainly is the reason we bought the water and it's a good reason to sell the water to Las Brisas," he said.

Members of the International Brotherhood of Electrical Workers union, Coastal Bend Associated General Contractors, Corpus Christi Chamber of Commerce, Corpus Christi Hispanic Chamber of Commerce, Workforce Solutions, Craft Training Center of the Coastal Bend and Corpus Christi Regional Economic Development Corp. spoke for the plant.

Proponents said the council should leave the decision on Las Brisas to the Texas Commission on Environmental Quality, where engineers review the permit and three appointed commissioners have the final say. Opponents painted the agency as pro-business and untrustworthy.

Two administrative law judges oversaw a two-week hearing in November and in March issued a recommendation that the permit either be denied or sent back to the agency for further review.

Las Brisas officials have said they are confident the permit will be issued. It has not yet been placed on an agenda but could be within the next two months.

STP Attachment 25

Official Transcript of Proceedings

NUCLEAR REGULATORY COMMISSION

Title:	Draft EIS for South Texas Project Public Meeting: Afternoon Session
Docket Numbers:	52-012, 52-013
Location:	Bay City, Texas
Date:	Thursday, May 6, 2010
Work Order No.:	NRC-201

Pages 1-109

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And there's two letters here.

(Applause.)

FACILITATOR CAMERON: Next, we're going to go to Tom Smith. And I have to apologize to Smitty, we don't provide capability for people to show PowerPoint here, and he does have PowerPoint, but we are going to attach the PowerPoint to the transcript. Tom Smith.

MR. SMITH: Good afternoon. My name is Tom Smith. I'm better known as Smitty, and I'm here because I don't think the NRC has done an adequate job in analyzing the need for the plant. And if the plant is not needed, then we, as tax payers, and you, as residents of Matagorda County, may end up with a plant that is never completed, and may end being an economic albatross, both through having to pay out on the loan guarantees, but with you having a plant that's never completed, and dreams unfulfilled.

I don't think the NRC has done an adequate job in looking at the efficiency potential, and the potential for renewables, combined heating and power, geothermal, the impact of what we call nodal transmission, or nodal dispatch, and demand side management. Without a doubt, Texas is going to need some kinds of new sources of electricity. The

Electric Reliability Council says we need 30,000 megawatts of new energy. We don't think we need anywhere near that, but I'll get into that in just a minute.

But what's important is that study, after study, after study, after study all show that nuclear power is the most expensive way to meet our energy needs of the future. Industry studies indicate that energy efficiency, wind, coal with carbon sequestration, natural gas with carbon sequestration are all lower cost than nuclear power. The Federal Energy Regulatory Commission has similar numbers. And a study we had a consultant do last April by a former expert for the Office of Public Utility Council in Texas, came to the same conclusion. But what he showed in his study, which I think is important, is that it's 20 years before this plant starts to make a profit. And, at some point, the investor community is going to get wise to this, and say why would we invest in a plant like this, if there are a bunch of cheaper ways to end up making money, and to generating electricity?

Now, the plant originally was expected to cost about $5.4 billion, is now $18.2 billion. The plant's cost has trebled before we've even turned dirt out here. And, as a result, there aren't a whole lot of buyers showing up in the marketplace, either as partners, or who are likely going to end up buying the power, if it's finally produced and sold on the open market.

And one of the things that's important to recognize is the folks who are in charge of determining whether we need power, the Electric Reliability Council of Texas, haven't done their homework. They haven't really looked at the amount of wind we've got, potentially, or amount of energy efficiency, haven't added in all the coal plants that have been permitted, or are close to being permitted. For example, they assume that wind only blows 8.7 percent of the time. I've been to your coast. I know it's a hell of a lot stronger than that. The numbers on the coast seem to be around 40 percent of the time, high 30s in the evenings and night out in the West Texas wind areas.

A number of studies done for the PUC and others indicate that we can meet 101 percent of our demand for electricity in the I-35 corridor, and about 76 percent of the growing demand over that same period of time through energy efficiency. We will need some new power plants in the industrial belt along the coast, but not nearly as many as the Electric Reliability Council of Texas has indicated we will.

You all know about cogen. There's about another 15,000 megawatts of cogen out there that have never been plugged in that could be utilized. And there's a great untapped resource called geothermal energy that's underground. And anybody who has ever drilled for oil and gas knows one of your problems is you've got to deal with the hot stuff, the hot water, the hot brines that come out from underground. That can be turned into electricity and sold to the grid.

I've got bad news for you all. We are number two in the nation, and those nasty people on the other side of the Red River, the Sooners have got more of it than we do, but we have more than 5,000 megawatts of geothermal energy that are about half the cost of the nuclear power plant just waiting underground to be used, about 5,000 megawatts.

Energy storage is right on the horizon. And we know how to do it, we've been doing it for over 50 years with compressed natural gas. We can do it with wind, and other kinds of renewable energies. So, let me give you some of the big numbers you would have seen on the chart. We think that there's about 1,100 -- what STP is fixing to put out, about 2,600 megawatts. We think we can save 1,100 megawatts with the new building codes that are now required in Texas, 154 megawatts with better appliances, 3,300 megawatts with the programs that the Public Utilities Commission is putting in there. There are 1,900 megawatts of new permitted coal that aren't in the NRC report that you saw up here, and we think there's another 2,400 likely to get permitted within the next six months.

We think that there is about another 3,500 megawatts of geothermal that's likely, and other non-wind resources that could be put on line in the same period of time at a fraction of the cost. And that the real number is probably about 8,000 megawatts of wind on peak, off peak, serving as baseload with storage. And 15,000 megawatts of combined heating and power that could economically be put into place.

The bottom line is, that entire capacity hole under the worst case scenario of 30,000 megawatts and leaves another 5,000 on the table leftover, spare. There's not a market for this power plant. There's no real need for the power plant. And we don't think the NRC did a good enough job at looking at the need for the power plant, or its alternatives.

What does that mean for this community, and what does that mean for the United States government? If loan guarantees are granted, if this plant is started, somewhere along the line the market is going to do what markets do, and say this power is too expensive to use, and this plant will never be completed. And we believe that the NRC needs to go back and take a good hard look at the basis of the assessment for the analysis of need, and alternatives. Thank you all very much.

FACILITATOR CAMERON: Thank you, Smitty.

(Applause.)

FACILITATOR CAMERON: Michael Griffith, and then we'll go to Karen Hadden, and Steve Smith, and then Kaley Roberts.

MR. GRIFFITH: I'm Mike Griffith with Port of Bay City Authority. We're the local sponsor for the federal project, which is Colorado River Navigation Channel. We've been affiliated with the nuclear plant in some of their activities, and they've been a great partner. And the Port fully supports the expansion of Units 3 and 4.

Just personally, I've served on many local boards, and civic organizations with employees of the nuclear power plant, and it's evident that they receive training, and they have a team effort, and they bring a lot to all of these boards. And it's just comforting to know that these are the people that are out there operating this plant, and it seems like it's been a very professional and good manner. So, that's all.

FACILITATOR CAMERON: All right. Thank you, Michael.

(Applause.)

FACILITATOR CAMERON: Karen, are you ready? This is Karen Hadden.

MS. HADDEN: Good afternoon. Like Tom "Smitty" Smith ahead of me, I would like to relay some of my concerns with the Draft Environmental Impact Statement on behalf of the SEED Coalition, Sustainable Energy and Economic Development Coalition.

The Draft Environmental Impact Statement is not adequate. It does not have adequate scientific analysis on many fronts, and it paints a glossy picture, while minimizing risks. I have come to call it the "Don't Worry Be Happy Report." We will be submitting written comments, and more detailed comments in the future.

Many of our original concerns remain, and we've spoken with scientists all along and tried to give input for this study, but it appears to have been disregarded. We have concerns with safety, security, radiation risks for the general population, and for workers, radioactive waste problems that still have no solution, and the consumption of vast quantities of water.

The STP proposed reactors are incredibly expensive. They could be as much as $22 billion, according to one study. Federal loan guarantees, if granted, and if there were to be a default, would cost billions of dollars, and all U.S. tax payers would be left with that bill.

If there was a serious accident at South Texas Project, hopefully, there never will be, it could impact the whole State of Texas, not just Bay City. A 1982 report that was done for the NRC by Sandia Labs found that there could be 18,000 early deaths if there was a meltdown. That would be followed by thousands of cancers, and they would not be limited to Bay City. These are risks that Texans don't need, risks that we don't need to take. There are ways to generate electricity. There are safe, affordable, less risky options to do so, and plenty of ways to have economic vitality in the community without building nuclear reactors.

The Environmental Impact Statement uses the categories of small, medium, and large. These are not scientific terms. These are not numbers, and, yet, they are used throughout the EIS without giving corresponding numerical parameters. This is not scientifically valid. This is a judgment call.

Water use, again, is of a great concern. The Draft EIS points out that in 26 of 60 recent years, the Colorado had lowered river flow. It was 75 percent of the average flow during those years. The lowest the river has gotten down to is 20 percent of the average flow, so while STP may be allowed to use up to 100,000 acre feet per year, there is no guarantee that that water will be there. Last September, the water in the main cooling reservoir got quite low, and extensive pumping was needed to refill it in a time of serious drought.

The proposed reactors, Units 3 and 4, would use over 23,000 gallons per minute, per minute. That is filling 1,440 swimming pools in one day, backyard swimming pools. So, this vast consumption of water raises the question of how will other users get water if there is a drought, the water needed for rice farming and ranching, the water needed for recreation. Together with all four reactors, the site would use 42,604 gallons per minute.

In addition, there would be ground water use of 1,860 gallons per minute, and I would recommend, and I don't see it in the EIS, that the water be tested to make sure that there's no radioactivity, since that will be drinking water.

The aquatic organisms have been identified in the Environmental Impact Statement, which is great. They're supposed to do that. They did impingement testing, testing what's there in the reservoir, and they looked at what's out there around in the community. What they did not do was take any of these organisms into a laboratory and find out, is there radioactivity already here? Is there tritium already here? And they should. There's condition reports from the plant that say there is tritium getting into the Colorado River, not high levels compared to other sites around the country, but it's there. There are reports that show that the monitoring wells have increasing levels of tritium. Why were these organisms not tested, fish, snakes, invertebrates, birds, shell fish, blue crabs, oysters, and even the larger aquatic mammals. No testing, and we recommended this from day one.

In terms of that, the EIS acknowledges the shortcoming in data, and they simply say STPNOC does not conduct any routine monitoring of aquatic resources of the site. Regulatory agencies have not required ecological monitoring of the STP site, and it hasn't been done, even with this Draft Environmental Impact Statement looking to build two more reactors.

According to the Environmental Impact Statement, there were over 122,000 people living within 50 miles of the South Texas Project site. They could, according to the document, be exposed to 2.5 millirem per year from the two proposed units. No mention was made at the same time of exposure from the existing units, and what the cumulative impact is, nor any kind of real estimate of what the health risks are from this level of exposure.

These are some of the many reasons that we're concerned. I would like to note that in terms of looking at the pathways, and the organisms, the testing that was done involved visual inspection. They requested laboratory -- we requested laboratory testing, but what was actually done was that people came out and toured the site. You cannot tell if an organism has absorbed radiation by looking at it. You do need to go into a laboratory. That has not been done. And there needs to be significantly more work done on this Draft Environmental Impact Statement.

FACILITATOR CAMERON: Thank you, Karen.

There are 105 or so nuclear plants operating in this country. I haven't heard of this massive number of 212, or 100,000 people killed in any of the nuclear accidents, not even including Chernobyl, the worst case, the worst in the history of nuclear industry. So, I very strongly recommend to NRC that they should have no hesitation to approve and issue a license, operating license to STP, and STP will do a fine job. And I'm sure we'll come here 10 years later and say that what we are saying today is true, and the plant is built, running efficiently, and helping the community. Thank you.

(Applause.)

FACILITATOR CAMERON: Thank you very much. Susan Dancer.

MS. DANCER: Thank you, Chip. Thank you guys for coming. My name is Susan Dancer, and before I give any more about myself in the way of introduction, or what I'm here to speak to you about, I want to try to paint a picture of what the atmosphere is like here in Bay City in Matagorda County, so that you can better understand my position today.

I'd like to read a couple of excerpts from an email from Mr. Mitch Thames, who spoke earlier, from his office, and I will provide you with a copy of the entire email so that you can have it in its entirety. This is from April the 30th, and this is a forward from Police Chief Barker. It looks like maybe it went to everybody in the Police Department, and here are just some excerpts.

"This is a very important meeting. It is critical that we show support for our future in the construction of STP Units 3 and 4. Just like last time, the opposition will bus in out-of-town people to speak. Don't sit home and let them speak for you. If you don't want to speak, we have to have you here showing support. Just show up and sit with our team. Showing strong local support for STP expansion Unit 3 and 4 at this meeting is important. STP is the largest employer in Matagorda County with more than 1,200 employees. Units 3 and 4 will add an additional 800 permanent jobs to the local economy. Strong support from local businesses and residents is important, as the NRC considers STP's federal license application. Displaying strong community support for this project is important."

What bothers me about city officials, including our Police Department's highest ranking official getting involved at that level is that the effect on people here is too often -- they feel squelched by their employers, and they don't feel empowered to educate themselves to speak their mind. What bothers me is the mischaracterization that opposition is bussed in. I have been to every hearing here so far, I have yet to see a bus.

What bothers me the most is the hearing, I feel is made a mockery and a sham as local authorities try to make it a popularity contest. I have yet to see one single local official encouraging the populous to read the actual document that we should be here today to discuss with the seriousness becoming it, the environmental impact of a nuclear expansion on our community, nor do I believe that any official who addressed you today has read the document. And I challenge everyone who stands here today before they begin their address, to state whether or not you've actually read the EIS that you're here addressing, or if you're just here to give support.

I am from Matagorda County, I was born and raised here. I'm a third or fourth generation, depending on which side of the house you look at, Matagordaian, one of the few locals you will hear speak against the expansion and its impact on our environment and socioeconomic status. And while we're talking about who's from where, I'd like to issue a challenge to our STP leaders, who are here to speak to you today, to proclaim their loyalty to Matagorda County, to tell you before they begin their presentation what county they reside in.

I believe that although the NRC makes every opportunity to have every citizen heard, and thank you for that, for coming. I really do appreciate the chance to participate. For reasons mentioned earlier, the citizens are not allowed, in many cases, to voice opposition. Because of that fact, I want everyone to know that Karen Hadden from the SEED Coalition, and Smitty from Public Citizen are here at my request. I actually contacted them back in 2006 when I became concerned about an apparent lack of commitment from STP to our community, might have been 2005, actually, I'm not sure about that. But this is before Unit 3 and 4 were ever on the board. I contacted them, found them on line, and asked them to help me intervene in trying to get some more things brought to light in this community, so they're not just here bused in from Austin, they're here because I asked them to be.

You will hear STP officials pledge their concern for the physical environment, and they do have responsibility for a huge chunk of our county, about 12,000 acres, I think. But who is this land's husbandry entrusted to, the lowest bidder. Things like toxic herbicide and pesticide applications, and wildlife management are handled by some of the lowest paid, least well-trained contractors on site, not in-house employees. Our state's wildlife and fur bearing animals laws are regularly broken as underpaid, inexperienced staff kill protected species, relocate infectious disease specimens, and kill off honeybee swarms necessary for pollination of our food crops.

I have personally spoken with some of the contractors, and the STP personnel in charge of them on multiple occasions. I'm a state-licensed wildlife rehabilitator, and regularly teach classes on peaceful and safe coexistence with our native species. When I offered to teach, or provide other instructors or free resources during the last wildlife crisis at STP, I was told, and I quote, "We're not ready to take it to that level." What does that say to you about STP's real commitment to the environment where the rubber meets the road?

Socioeconomically, STP proponents say that the expansion is good for our area, yet 30 percent of the children in the districts closest to STP live below the poverty level, and Matagorda County's unemployment is the highest in the state. Is that STP's fault? No, of course not, but they do play a role. The only way for us to get out of our economic slump is to acknowledge how we got here, and in that STP does have a role. Here's how it works.

You get a big construction project going on. You get an influx of people from around the country, and in this case even from around the world. And each professional who comes seeking job brings with him an un- or under-skilled spouse, 2.3 children, and encourages others to come with him, as well. Each of these others come into the scenario and compete with locals, who are already here, for the menial jobs they already have. Unemployment here skyrockets. -- Can you hear me?

FACILITATOR CAMERON: Why don't you try this one, but I'm going to have to ask you to just sort of give us a summary.

MS. DANCER: Okay, I'm there. Okay. Thank you. Okay. Socioeconomically, where am I? Sorry about that. Meanwhile, infrastructure costs are borne mostly by existing locals for classrooms, hospitals, roadways, law enforcement efforts go through the roof, so people already established here get a double whammy.

Mr. Thames' email promotes another entry, that the STP employee basis here contributing to Matagorda County, the truth is that a very large percentage of the current 1,200 employees, and likely 800 to come live elsewhere. A huge chunk of STP's upper managers live in neighboring Brazoria County, leaving Matagorda County the risk, the infrastructure burden, and the economic backlash that worsens the very issues it proposes to remedy.

Another undeniable factor in STP's inability to be the answer to our economic woes is that STP's upper management positions appear to be only open to white males. I have created a few charts here that show the racial and gender makeup of Matagorda County versus the percentage of minorities and women in the highly touted, highly sought after, high paying jobs at STP.

The fact of the matter is that STP 1 and 2 did not bring prosperity to our community by any economic indicator one may use, child poverty, unemployment, et cetera. The fact of the matter is the local people look realistically at indicators via the EIS process, expanding the nuclear plant seems to only worsen our situation.

For the record, I'm also concerned about water usage, tritium, other radionuclide contamination, financial burden of nuclear energy, generally speaking, on the tax payer as far as loan guarantees, and waste storage. I hope that others here can address those scientific issues better than I. Thank you for coming to Matagorda County.

(Applause.)

FACILITATOR CAMERON: Thank you, Susan. We're going to go to John Corder right now. And I should have introduced him before. This is Scott Burnell, who's our top Office of Public Affairs representative with us tonight, and fixes microphones. We'll see how well you did. John.

MR. CORDER: Good evening. My name is John Corder, and I live at 313 County Road, 912 in Brazoria County. Transcending anything that's been said either way, we have the freedom of speech, and I am exercising that tonight, and I appreciate it.

Under public comments, my conversation is about communication. Being in communication with STP, NRC, the Corps of Engineers, Texas Commission on Environmental Quality, U.S. Senators and representatives. The purpose of the communication is to know for yourself. I am an intervener. Am I an

STP Attachment 26

COOLING & TOWERS SALT WATER

By John A. Nelson • The Marley Cooling Tower Company • November 5, 1986

WHAT IS SALT WATER?

For cooling tower service, any circulating water with more than 750 parts per million chloride expressed as NaCl is generally considered as “salt water”. However, the effects of chlorides will be much less severe at 750 ppm than they will at higher concentrations. Salt water may be from the open ocean, brackish (estuarine) or from brine wells. Since an open recirculating system concentrates the dissolved solids in the makeup water, a cooling tower may be exposed to salt water service even though the makeup contains less than 750 ppm NaCl.

If makeup for the cooling tower is from the open ocean, the hypothetical composition will be:

185 ppm	$Ca(HCO_3)_2$
1,200 ppm	$CaSO_4$
2,150 ppm	$MgSO_4$
3,250 ppm	$MgCl_2$
27,000 ppm	NaCl
500 ppm	KCl
100 ppm	KBr
Salinity	35,000 ppm
Total Alkalinity	115 ppm as $CaCO_3$
pH	About 8

HOW DOES IT AFFECT THE COOLING TOWER?

Materials—The primary effect of salt water is to increase the corrosion rate of metal in the cooling tower and the cooling system. It may cause fiber loosening on wood components which are alternately wet and dry. These effects can be overcome by proper selections of materials and coatings, as described on the next page.

Fouling—Fouling can be biological (slime or algae), inorganic (scale) or variable contamination (oil, debris, etc.). Suspended abrasive matter (sand) may be a problem and may increase corrosion and wear.

Thermal Performance—Salt has three basic effects upon water which affect thermal performance. It lowers the vapor pressure, reduces the specific heat, and increases the density of the solution. The first two tend to decrease thermal performance but the latter effect tends to increase it. However, the compensating effect of increased density is not sufficient to totally offset the effects of reduced specific heat and vapor pressure, so some loss of thermal performance results. The amount of loss is greater for higher salt concentrations and for more difficult cooling duties. For a circulating water with 55,000 ppm salinity, the anticipated loss of thermal performance of a typical mechanical draft cooling tower ranges from 2% to 4%, depending upon the difficulty of the cooling duty. The loss of thermal performance can be regained by adjusting several variables, such as: tower size, fan horsepower or circulating rate. Marley's Performance Section has rating systems which can determine the reduction in tower capacity for any degree of salinity and any thermal requirement, so accurate sizings are readily available for applications with salt water makeup.

HOW DOES A SALT WATER COOLING TOWER AFFECT THE ENVIRONMENT?

The primary concerns in a salt water cooling tower are drift and blowdown. For all practical purposes, the drift and blowdown will contain the same concentration of total dissolved solids as the circulating water. Methods are currently available for determining the total quantity of drift and the drift droplet size distribution. The actual drift rates from most modern cooling towers will range from .005 to .02% of the circulating rate. Drift rates below .005% are attainable with special attention to the eliminator designs and details. For a more complete discussion of drift, see the Marley booklet, Drift Technology For Cooling Towers, by Holmberg and Kinney, 1973. Even though low levels of drift are achievable, a salt water cooling tower should not be located close to sensitive equipment.

Blowdown from a salt water cooling tower will contain some multiple of the total dissolved mineral matter in the makeup, but in the case of sea water makeup, it would be unusual for the final concentration in the cooling tower to exceed two times that of the makeup. At the present time, there appears to be no major problem with the disposal of blowdown from salt water cooling towers, providing toxic materials have not been added to the circulating water. However, the subject of blowdown disposal is very complex and potential users of salt water cooling towers should check the authorities having jurisdiction.

WHAT PRECAUTIONS CAN BE TAKEN?

Structure—Ordinarily made of wood, steel or concrete for fresh water. Because of the corrosiveness of salt water, a steel structure should be avoided. California redwood or Pacific Coast Douglas fir, pressure treated with durable preservatives, perform well in salt water service. There is no major difference in wood durability between a salt water cooling tower and one utilizing fresh water makeup except that the high concentration of dissolved solids may cause surface damage in areas which are alternately wet and dry. This effect is no different than that experienced in fresh water of very high alkalinity and/or very high total dissolved solids. Concrete should be made with Type II Portland cement for maximum resistance to sulfate attack and the mix should be rich, with a low water to cement ratio. The concrete should be dense and air entrained. A microsilica admixture is also beneficial. Rebar should be epoxy coated. Connectors and hardware in the structure should be resistant to salt water. Plastics and ceramics are inert to the effect of salt water and their use is desirable. Silicon bronze is the recommended alloy for bolting in the structure unless the circulating water will be contaminated with sulfides. Exposed portions of silicon bronze hardware need protection from falling droplets to avoid erosion/corrosion. Anchor castings and other castings in the flooded sections of the tower should be of red brass or silicon bronze.

Casing and Louvers—Glass reinforced polyester is the most commonly used material for these components. This material resists salt water very well. All joints in the casing, horizontal as well as vertical, should be sealed to avoid the buildup of salt deposits in the joints.

Fill and Eliminators—These may be made of wood or durable plastics. All of these perform very well in this application in salt water towers.

Fan Cylinders—These currently are most commonly made of glass reinforced polyester which is very durable in salt water exposures. Hardware in the fan cylinders should be stainless steel or silicon bronze.

Mechanical Equipment—Fan blades may be of glass reinforced polyester or epoxy or coated aluminum. Geareducers, bearing housings and fan hubs may be made of cast iron provided they are protected with a heavy coating of epoxy enamel. Mechanical equipment supports and welded steel fan hubs should also be protected with a heavy coating of epoxy enamel. Drive shafts should be made with type 316 stainless steel. Fasteners in the mechanical equipment should be type 316 stainless steel also. Stainless steel resists salt water very well in areas which are highly aerated. It also polarizes readily so it causes little or no galvanic corrosion of less noble metals with which it is in contact in the plenum area.

Distribution System—Unprotected steel pipe should be avoided. PVC and glass reinforced polyester pipe perform well in salt water service. Steel and cast iron fittings in the distribution system should be coated with epoxy enamel or porcelain. The hardware used in the distribution system should be 316 stainless steel, monel or silicon bronze. Silicon bronze should not be used in areas of high velocity.

Cold Water Basin—Generally made of concrete or wood. Steel should be avoided. Wood basins are not adversely affected by salt water. Concrete basins should be made with a rich mixture utilizing Type II Portland cement, should be dense and should utilize low water to cement ratios. Air entrainment is also beneficial.

Fouling—Algae and slime can be prevented by the prudent use of biocides. Chlorination is commonly used and is very effective in sea water towers since it releases bromine. Usually 1/2 ppm free residual chlorine is adequate for control. However, if marine animals are present, chlorination to as much as 3 ppm may be required and continuous addition for periods as long as 72 hours may be required.

Alternating chlorination with nonoxidizing biocides may be required to maintain control. Scaling would be unusual in the cooling tower but may create heat transfer problems in exchangers. Generally, sea water may be concentrated to approximately 55,000 ppm salinity with no pH adjustment without serious scaling problems in the exchangers. Higher concentrations are possible but pH control by acid additions would probably be required. Two of the major users of sea water cooling towers operate to 55,000 ppm salinity as the upper limit and this procedure has been satisfactory.

Conclusion

Water cooling towers can be utilized where only salt water is available for makeup. With the proper selection of materials and coatings, long service life is achievable. Salt water, at the concentrations usually encountered, can be properly rated for thermal performance.

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The following references contain additional information which may be useful in the design or operation of circulating systems utilizing salt water. For availability, contact the reference source.

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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	Docket Nos. 52-012-COL
	)	52-013-COL
STP NUCLEAR OPERATING COMPANY	)	
	)	
(South Texas Project Units 3 and 4)	)	June 14, 2010

CERTIFICATE OF SERVICE

I hereby certify that on June 14, 2010 a copy of "STP Nuclear Operating Company's Answer Opposing New Contentions Based on the Draft Environmental Impact Statement" was served by the Electronic Information Exchange on the following recipients:

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