BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-29
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-30

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 131
Eddystone November Order

Department of Energy
Washington, DC 20585

Order No. 202-25-10

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in the PJM Interconnection, L.L.C. (PJM) region due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

Order Nos. 202-25-4 and 202-25-8

The Eddystone Generating Station is a power plant owned by Constellation Energy Corporation (Constellation Energy) and located in Eddystone, PA. Units 3 and 4 (Eddystone Units), each with 380 MW of generation capacity, are subcritical steam boiler-turbine generator units that can run on either natural gas or oil, depending on market conditions. The Eddystone Units were initially scheduled for retirement on May 31, 2025.

Order No. 202-25-4, issued pursuant to FPA section 202(c), required that the Eddystone Units remain in operation for 90 days, until August 28, 2025. Subsequently, Order No. 202-25-8, issued pursuant to FPA section 202(c), required the Eddystone Units remain in operation for 90 days, until November 26, 2025. Those orders were based on my determination that emergency conditions existed in the PJM region. I explained that there was a potential shortage of electric energy and a shortage of facilities for generation of electric energy. I stated that the potential loss of power to homes and local businesses presents a risk to public health and safety. I determined that the operational availability and economic dispatch of the Eddystone Units was necessary to best meet the emergency and serve the public interest. My determination was based on a number of different facts.

First, in congressional testimony, PJM's president and CEO recently stated that its system faces a "growing resource adequacy concern" due to load growth, the retirement of dispatchable resources, and other factors.[3] Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] *Keeping the Lights On: Examining the State of Regional Reliability*, Before the *H. Comm. on Energy and Com., S. Comm. on* Energy, 119th Cong. (Mar. 25, 2025) (testimony of Mr. Manu Asthana, President and CEO of PJM) (Asthana Test.) at 4-5, available at https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf.

of resources in PJM's interconnection queue.[4] Upcoming retirements, including the planned retirement of the Eddystone Units, would exacerbate these resource adequacy issues.

Second, PJM indicated that resource constraints could exist within its service territory under peak load conditions, stating that "available generation capacity may fall short of required reserves in an extreme planning scenario."[5] In its February 2023 assessment "*Energy Transition in PJM: Resource Retirements, Replacements & Risks* (Four Rs Report)," PJM highlighted increasing reliability risks in the coming years due to the "potential timing mismatch between resource retirements, load growth and the pace of new generation entry" under "low new entry" scenarios for renewable generation.[6]

Third, in December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found "the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry."[7]

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order No. 202-25-4 and Order No. 202-25-8 continue, both in the near and long term.[8] The production of electricity from the Eddystone Units will continue to be critical to maintaining reliability in PJM over the coming winter months. According to U.S. Environmental Protection Agency data, the Eddystone Units

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[4] *Id.*; *see also PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084, at P 15 (2025) (*PJM Interconnection*) (PJM states that, in 2023, "it found that generator retirements, load growth, the pace of new entry, and the operating characteristics of the intermittent and limited duration resources that make up a large part of PJM's interconnection queue pose increasing reliability risks through 2030.").

[5] *PJM Summer Outlook 2025: Adequate Resources Available for Summer Amid Growing* Risk, PJM. (May 9, 2025), https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/.

[6] *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, PJM (Four Rs Report) at 1, (Feb. 24, 2023), https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjmresource-retirements-replacements-and-risks.ashx.

[7] *PJM Interconnection*, 190 FERC ¶ 61,084 at P 14.

[8] Further, it likely would be difficult for the oil-fired units to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. Further, if Constellation Energy were to begin disassembling the units or other related facilities, the associated challenges would be greatly exacerbated. Thus, continued operation is required in such cases so long as the Secretary determines that an emergency exists.

generated 26,434 MWh between June 2025 and September 2025,[9] providing vital generation capacity to the region. Over the course of the summer, PJM issued Hot Weather Alerts and/or Maximum Generation Alerts (EEA 1) to manage grid reliability covering a total of 20 days, including days in June, July, and August.[10]

PJM's resource adequacy concerns are well documented. In January 2025, PJM reached a new record peak for winter demand, exceeding the previous winter peak set in 2015[11] and in PJM's 2025 Long-Term Load Forecast, PJM noted that "20-year annualized growth rate in the 2025 Long-Term Load Forecast for the winter peak is up to 2.4%."[12] Further, PJM's risk profile continues to shift from the summer season to the winter season. For example, in a March 2025 presentation, PJM estimated that 87.8% of the expected unserved energy for the 2025/2026 delivery year falls in the winter season.[13]

The evidence also indicates that there is a potential longer term resource adequacy emergency in the PJM region.

In a news release expressing support for Order No. 202-25-4, PJM explained that it has "repeatedly documented and voiced its concerns over the growing risk of a supply and demand imbalance driven by the confluence of generator retirements and demand growth. Such an imbalance could have serious ramifications for reliability and affordability for consumers."[14]

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[9] *See Custom Data Download, EPA CAMPD* (Clean Air Markets Program Data), https://campd.epa.gov/data/custom-data-download (search criteria Emissions >> Monthly >> Unit (default) >>Apply >>*"2025" and "June, July, August, September."* The data can then be filtered to only include the Eddystone Generating Station.

[10] *See* PJM Emergency Procedures Postings for the period between June 1 and August 31, *Emergency Procedures*, https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf (search range set to: effective from 06/01/2025 until 08/31/2025).

[11] *Jan. 22 Update: Extreme Cold Produces PJM Record for Winter Electricity Demand*, PJM (Jan. 22, 2025), https://insidelines.pjm.com/jan-22-update-extreme-cold-produces-pjm-record-for-winter-electricity-demand/.

[12] *2025 Long-Term Load Forecast Report Predicts Significant Increase in Electricity Demand*, PJM Interconnection, L.L.C. (Jan. 30, 2025), https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/.

[13] *2026/27 BRA IRM, FPR, and ELCC Class Ratings: Shift Towards More Winter Risk*, PJM Resource Adequacy Planning Special Planning Committee, at 8 (Mar. 13, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250313-special/2026-2027-irm-fpr-elcc-and-winter-risk.pdf.

[14] *PJM Statement on the U.S. Dept. of Energy 202(c) Order of May 30*, PJM Interconnection, L.L.C. (May 31, 2025), https://insidelines.pjm.com/pjm-statement-on-the-u-s-department-of-energy-202c-order-of-may-30/. Further, PJM concluded, "In light of these concerns, PJM supports the U.S. Department of Energy's Order, issued May 30, pursuant to Section 202(c) of the Federal Power Act, to defer the retirements of certain generators operating in PJM's footprint . . . ." *Id.*

PJM has indeed voiced these concerns for years. In its February 2023 Four Rs Report, PJM cautioned that 40 GW of thermal generation are at risk of retirement by 2030.[15] PJM also noted that, while there were then 290 GW of renewable generation capacity in the PJM interconnection queue, historically, the rate of completion for renewable projects is approximately five percent.[16] PJM determined that the pace of new capacity additions "would be insufficient to keep up with expected retirements and demand growth by 2030."[17] PJM estimated that, depending on the pace of new capacity additions, reserve margin erosion would occur between 2026 and 2028.

More recently, in its December 2024 RRI filing with FERC, PJM stated that "[c]oncerns about resource adequacy . . . have only increased since the Four Rs Report . . . ."[18] PJM warned that its "resource adequacy concerns are increasing at an extraordinary pace."[19] PJM went on to explain, its "resource adequacy concerns are driven in large part by significant load growth caused by, among other things, large data centers" and that its preliminary analysis shows "substantial increases [in load additions] since the 2024 forecast" for both the summer and winter seasons.[20] According to PJM, "load growth and generator retirements are significantly outpacing the entry of new generation in the PJM Region with this trend expected to continue unabated based on all available evidence."[21] Although the RRI process will help expedite the construction of needed new capacity, it is unlikely to result in the addition of any new generation capacity in the next few years.[22]

In support of the RRI filing, PJM submitted an affidavit from Donald Bielak, PJM's Director, Interconnection Planning. Mr. Bielak characterized the increase in forecasted load growth throughout PJM as "extraordinary" and "unprecedented," stating that it "could not have been foreseen as recently as a year ago."[23] Mr. Bielak expressed the opinion that the "rapid" retirement of thermal generation resources, "extreme" forecasted load growth, and "delays in new generation resources achieving commercial operation," would adversely affect resource adequacy throughout PJM's electricity grid.[24]

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[15] Four Rs Report at 2.
[16] *Id*.
[17] *Id.* at 16, Table 1.
[18] *PJM Interconnection, L.L.C.*, FERC Docket No. ER25-712, Tariff Revisions for Reliability Resource Initiative at 10 (Dec. 13, 2024).
[19] *Id*.
[20] *Id.* at 10-11. *See also id.* at 13 ("the exponential load growth resulting from development of new data centers and the intense energy needs of Artificial Intelligence technology overshadows any relaxation in the pace of fossil fuel generation retirements . . . .").
[21] *Id.* at 14.
[22] *See id.*, Attachment C (Affidavit of Mr. Donald Bielak), at PP 18-19 (explaining that projects studied in Transition Cycle #2, which includes RRI projects, "could be constructed and in commercial operation by the 2029/30 Delivery Year or sooner.").
[23] *Id*. at P 10.
[24] Id. at P 12.

On February 11, 2025, FERC accepted PJM's RRI filing.[25] In its order on rehearing, FERC concluded, "PJM identified increasing reliability risks arising in the next few years and significant resource adequacy issues anticipated by the 2030/31 delivery year. The record supports that these resource adequacy concerns are likely to manifest."[26]

NERC has raised similar concerns. According to NERC's 2024 Long Term Reliability Assessment, "PJM could face future resource adequacy challenges, impacting system reliability and PJM's ability to serve load."[27] NERC assessed the PJM region at an elevated risk starting in 2026,[28] explaining that "[r]esource additions are not keeping up with generator retirements and demand growth."[29] NERC stated that the loss of-load hour (LOLH) and expected unserved energy (EUE) risks are concentrated in the winter months (especially January), in both 2026 and 2028.[30]

Order Nos. 202-25-4 and 202-25-8 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[31] President Trump likewise recognized, in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[32] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[33]

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[25] *PJM Interconnection*, 190 FERC ¶ 61,084 at P 263.
[26] *PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,085, at P 25 (2025).
[27] *Long-Term Reliability Assessment*, North American Electric Reliability Corporation, at 92 (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20 Assessment_2024.pdf at 92.
[28] *Id.* at 4.
[29] *Id.* at 7.
[30] *Id.* at 91-92.
[31] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (Strengthening the Reliability and Security of the United States Electric Grid), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-thereliabilityand-security-of-the-united-states-electric-grid/.
[32] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (Declaring a National Energy Emergency), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.
[33] *Id*.

The Department of Energy's (Department) July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President's directive in Executive Order 14262, details the myriad challenges affecting the Nation's energy outlook. It concludes, "Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[34] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. For example, PPL Electric Utilities has 11.7 GW of advanced data center requests in Pennsylvania through to 2030.[35] As of December 2024, Dominion Energy has 40.2 GW of contracted data center capacity, which is an 18.2 GW increase over the amount from July 2024, an approximately 88% increase.[36] Regarding the PJM region, the Department's analysis performed this year in collaboration with the national labs modeled the effects of approximately 25 GW of load growth in PJM, of which 15 GW came from data centers, as well as approximately 17 GW of announced coal, gas, and oil generation retirements.[37] Under these assumptions, the model estimated approximately 430.3 loss of load hours in an average weather year. Under worst weather year assumptions, the model estimated 1,052 loss of load hours and a max unserved load of approximately 21.335 GW.[38]

Grid operators, including PJM, have likewise acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the United States House of Representatives Committee on Energy and Commerce, Manu Asthana, President and CEO, PJM, testified that there was a "growing resource adequacy concern . . . impacting a significant part of our country."[39] Mr. Asthana explained that the "rate of electricity demand is anticipated to increase significantly in the future due to development of large data centers in the PJM service Area . . . [and] increases in demand coming from the transportation and heating sectors and from

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[34] *See also* Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, U.S. Department of Energy (July 2025), at 1, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[35] *See PPL Corporation Q2 2025 Investor Update*, PPLC Corporation, at 7 (July 31, 2025), https://filecache.investorroom.com/mr5ir_pplweb2/1245/PPL_2025_Q2_Investor_Update_vFINAL.pdf

[36] *See* Dominion Energy Virginia, Q4 2024 Earnings Call, at 18 (Feb. 12, 2025), https://s2.q4cdn.com/510812146/files/doc_financials/2024/q4/2025-02-12-DE-IR-4Q-2024-earnings-call-slidesvTCII.pdf.

[37] *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, U.S. Department of Energy, at 28 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[38] *Id.* at 27.

[39] Asthana Test. at 4.

industrial growth."[40] Mr. Asthana noted that, though various reforms instituted by PJM had succeeded in bringing new generation online and preventing the retirement of existing units, supply conditions within PJM are still tightening.[41] Therefore, Mr. Asthana stated that PJM "encourage[s] all generation owners who have signaled an intent to retire their units to reconsider their decision to support resource adequacy and grid reliability."[42]

Pursuant to section 202(c)(4)(B) of the FPA, the Department has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[43] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Eddystone Units when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-4 and 202-25-8 will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Eddystone Units is necessary to best meet the emergency arising from increased demand, determined shortage, and other causes and serve the public interest under FPA section 202(c).

To ensure the Eddystone Units will be available if needed to address emergency conditions, the Eddystone Units shall remain in operation until February 24, 2026.[44]

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[40] *Id.*
[41] *Id.* at 9-10.
[42] *Id.* at 10.
[43] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).
[44] 16 U.S.C. § 824a(c)(4).

Based on my determination of an emergency set forth above, I hereby order:

A. From November 26, 2025, PJM and Constellation Energy shall take all measures necessary to ensure that the Eddystone Units are available to operate. For the duration of this Order, PJM is directed to take every step to employ economic dispatch of the Eddystone Units to minimize cost to ratepayers. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by PJM pursuant to paragraph A. PJM shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Eddystone Units has operated in compliance with the allowances contained in this Order.

C. All operation of the Eddystone Units must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By December 11, 2025, PJM is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with this Order. PJM shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. Constellation Energy is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for the Eddystone Units to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Eddystone Units shall not be considered capacity resources.

H. This Order shall be effective from 00:00 PM Eastern Standard Time (EST) on November 26, 2025, and shall expire at 00:00 EST on February 24, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. at 2:30PM EST on this 25th day of November 2025.

Chris Wright

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Pennsylvania Public Utility Commissioners
Chairman Stephen M. DeFrank
Vice Chair Kimberly M. Barrow
Commissioner Kathryn L. Zerfuss
Commissioner John F. Coleman, Jr.
Commissioner Ralph V. Yanora

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Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-29
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Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 132
NIPSCO Rate Case Discovery Responses

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61 AND 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RETAIL RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS (BOTH EXISTING AND NEW); (3) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (4) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING, BUT LIMITED TO, AUTHORITY TO CAPITALIZE AS RATE BASE ALL EXPENDITURES FOR IMPROVEMENTS TO PETITIONER'S INFORMATION TECHNOLOGY SYSTEMS THROUGH THE DESIGN, DEVELOPMENT, AND IMPLEMENTATION OF A WORK AND ASSET MANAGEMENT ("WAM") PROGRAM, TO THE EXTENT NECESSARY; AND (5) APPROVAL OF ALTERNATIVE REGULATORY PLANS FOR THE PARTIAL WAIVER OF 170 IAC 4-1-16(f) AND PROPOSED REMOTE DISCONNECTION AND RECONNECTION PROCESS AND, TO THE EXTENT NECESSARY, IMPLEMENTATION OF A LOW INCOME PROGRAM.	)	**CAUSE NO. 46120**

NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC'S OBJECTIONS AND RESPONSES TO THE INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR'S NINTH SET OF DATA REQUESTS

Northern Indiana Public Service Company LLC ("NIPSCO"), pursuant to 170 IAC 1-1.1-16, the discovery provisions of Rules 26 and 37 of the Indiana Rules of Trial Procedure, and the October 9, 2024 docket entry in this Cause, by counsel, hereby submits

the following Objections and Responses to the Indiana Office of Utility Consumer Counselor's Ninth Set of Data Requests ("Requests").

General Objections

All of the following General Objections are incorporated by reference in the response to each of the Requests:

1. The responses provided to the Requests have been prepared pursuant to a reasonable investigation and search conducted in connection with the Requests in those areas where information is expected to be found. To the extent the Requests purport to require more than a reasonable investigation and search, Petitioner objects on grounds that they seek to impose an undue burden and unreasonable expense and exceed the scope of permissible discovery.

2. To the extent that the Requests seek production of electronically stored information, Petitioner objects to producing such information from sources that are not reasonably accessible because of undue burden or cost.

3. The responses provided to the Requests set forth the information in reasonably complete detail. To the extent that the requesting party contends that a Request calls for more detail, Petitioner objects to the Request on the grounds that it is overly broad, seeks to impose an undue burden and unreasonable expense, and exceeds the scope of permissible discovery.

4. Petitioners objects to the Requests to the extent they seek documents or information which are not relevant to the subject matter of this proceeding and to the extent they are not reasonably calculated to lead to the discovery of admissible evidence.

5. Petitioner objects to the Requests to the extent they seek an analysis, calculation, compilation or study which has not already been performed and which Petitioner objects to performing.

6. Petitioner objects to the Requests to the extent they are vague and ambiguous and do not provide a reasonable basis from which Petitioner can determine what information is sought.

7. Petitioner objects to the Requests to the extent they seek information that is subject to the attorney/client, work product, settlement negotiation or other applicable privileges.

8. Petitioner objects to the Requests to the extent they purport to require Petitioner to supply information in a format other than that in which Petitioner normally keeps such information.

9. Petitioner objects to the Requests to the extent that they seek production of documents created during an unreasonably long or unlimited period, on the grounds that the Requests are overly broad, seek to impose an undue burden and unreasonable expense, and exceed the scope of permissible discovery.

10. Petitioner objects to the Requests to the extent they request the production of information and documents not presently in Petitioner's possession, custody or control.

11. Petitioner objects to the Requests to the extent they request the production of (a) multiple copies of the same document; (b) additional copies of the same document merely because of immaterial or irrelevant differences; and (c) copies of the same information in multiple formats on the grounds that such Requests are irrelevant, overbroad, unreasonably burdensome, unreasonably cumulative and duplicative, not required by the Commission rules, and inconsistent with practice in Commission proceedings.

12. The responses constitute the corporate responses of Petitioner and contain information gathered from a variety of sources. Petitioner objects to the Requests to the extent they request identification of and personal information about all persons who participated in responding to each data request on the grounds that: (a) they are overbroad and unreasonably burdensome given the nature and scope of the requests and the many people who may be consulted about them; and (b) they seek information that is subject to the attorney/client and work product privileges. Petitioner also objects to the Requests to the extent they request identification of witnesses to be called in Petitioner's case-in-chief or rebuttal who can answer questions regarding the information supplied in the responses on the grounds that: (a) Petitioner is under no obligation to call witnesses

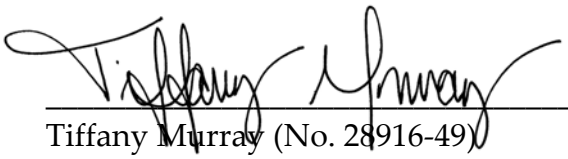
to respond to questions about information provided in discovery; and (b) the Requests seek information subject to the work product privilege.

13. Petitioner assumes no obligation to supplement these responses except to the extent required by Ind. Tr. R. 26(E) (1) and (2).

Without waiving these objections, Petitioner responds to the Requests in the manner set forth in the attached.

Dated this 4th day of November, 2024.

As to objections:



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CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served by email transmission upon the following:

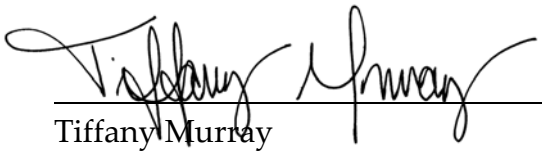
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A courtesy copy has also been provided by email transmission upon the following:

Barry A. Naum
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Dated this 4th day of November, 2024.



Tiffany Murray

Cause No. 46120
Northern Indiana Public Service Company LLC's
Objections and Responses to
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OUCC Request 9-001:

Please refer to NIPSCO MSFR 0635 providing historical and test year materials and supplies monthly balances.

a. Please provide a detailed breakdown of historical materials and supplies monthly ending balances by subaccount or category for January 2020 through September 2024.
b. Please provide supporting data, calculations, documents, and methodology supporting NIPSCO's forecasted decrease in materials and supplies monthly ending balances from $147,390,643 at the end of November 2025 to $133,826,242 in December 2025 when Schahfer Units 17 and 18 retire.

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation or compilation which has not already been performed and which NIPSCO is unable to prepare.

Response:

Subject to and without waiving the foregoing general and specific objections, NIPSCO submits the following response.

a. Please see OUCC Request 9-001 Attachment A (2020), OUCC Request 9-001 Attachment B (2021), OUCC Request 9-001 Attachment C (2022), and OUCC Request 9-001 Attachment D (2023). NIPSCO continues to compile information responsive for 2024 and will supplement as soon as the information is available. The support provided in OUCC Request 9-001 Attachments A through D can only capture information available at that specific point in time and does not specifically align with the balances and timing included in NIPSCO MSFR 0635. In addition, this is not a report that NIPSCO runs for every month so the detailed breakdown for February 2023, September 2023, and November 2023 is not available for those periods.
b. Please see Petitioner's Confidential Exhibit No. 18-S2 (Redacted) (p. 689), specifically Workpaper RB 13-S2, page [.4], for support of the referenced amounts as of November 30, 2025 by location. The forecasted balance through November 2025 is held constant to the December 31, 2023 amounts supported in this workpaper, therefore the workpaper amounts are also representative of

the November 30, 2025 forecasted balance requested. Please also see Petitioner's Confidential Exhibit No. 18-S2 (Redacted) (p. 692), specifically Workpaper RB 13-S2, page [.7], for support of the referenced amounts as of December 31, 2025 by location. The reduction is attributed to the removal of the Schahfer Gen Station balance on line 18.

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OUCC Request 9-002:
Please confirm that NIPSCO does not include emission allowance inventory or allowance consumption costs in the test year.
Objections:
Response:
Confirmed. NIPSCO did not include emission allowance inventory or allowance consumption costs in the Forward Test Year.

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OUCC Request 9-003:
If NIPSCO includes emission allowance inventory and/or allowance consumption costs in the test year, please provide the following by allowance type (SO_2, Annual NOx, and Seasonal NOx): a. For the months of January 2020 through September 2024: i. Beginning monthly balances; ii. The number of allowances added or purchased; iii. The value or price of allowances added or purchased; iv. The number and price of emission allowances sold; v. Gains or losses on emission allowances sold; vi. The number and cost of allowances consumed and the associated weighted average inventory cost at which they were charged; and vii. Brokerage fees.
Objections:
Response:
Not applicable. Please see NIPSCO's response to OUCC Request 9-002.

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OUCC Request 9-004:

Please state the total investment cost necessary for NIPSCO to continue operating Schahfer Units 17 and 18 after December 31, 2025.

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary, and/or trade secret.

NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request is vague and ambiguous as the term "investment cost necessary" is undefined such that the nature of information sought is unclear.

NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request is overly broad and unduly burdensome in that this Request is not limited to a specific time.

Response:

Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response:

The request contains an erroneous premise. NIPSCO cannot operate Schahfer Units 17 and 18 beyond December 31, 2025 and also complete the CT Project, for which a CPCN was approved by the Commission on October 16, 2024 in Cause No. 45947. Completion of the CT Project requires reuse of Schahfer's MISO interconnection rights, and NIPSCO's commitment to MISO to use those interconnection rights for the CT Project is due on December 31, 2024 (12 months before Schahfer's retirement date). NIPSCO has received preapproval of a significant future generation transition decision – to operate a nearly 400MW natural gas peaking unit - and that preapproval relies upon the 2025 retirement of Schahfer Units 17 and 18. Relating specifically to this Cause, because Schahfer's retirement is set to occur by the end of the Future Test Year, NIPSCO's case includes approximately $70 million in *associated reductions* to its proposed revenue requirement that will not be realized if that retirement date did not occur as expected.

The request is also untimely. The economics in support of Schahfer's retirement have been public record since 2018, and the retirement date for Units 17 and 18 has already been delayed once. NIPSCO's 2021 IRP demonstrated that retirement of Units 17 and 18 by *December 31, 2023* was most economic for customers, but NIPSCO made the

decision to delay retirement as a result of disruptions across the renewable industry including the COVID-19 pandemic, Department of Commerce involvement, and international supply chain disruption. This least-cost resource portfolio also included the addition of significant renewable generation, which NIPSCO has now added and is in the process of adding to its portfolio (1950MW in solar, wind, and solar plus storage as of December 31, 2025 (Figure 3 in Witness Cocking's direct testimony)) - as well as retirement of Michigan City Unit 12 by December 31, 2028, and the addition of a thermal peaking resource, which was recently approved by the Commission. Substantial planning and Commission-approved action is underway to execute this transition, as evidenced by the rate base additions proposed in this Cause.

NIPSCO has conducted two analyses since its 2021 IRP that are responsive to this Request – one of which has already been filed with the Commission in Cause No. 45772. Based on his 2022 analysis, NIPSCO Witness Augustine's 45772 testimony concluded that retaining NIPSCO's coal units to 2035 (Portfolio 3) resulted in significantly higher costs than the preferred portfolio from the 2021 IRP. This is because the capital and operating costs of delayed solar and storage projects and the additional solar, storage, and gas peaking capacity in the preferred portfolio from NIPSCO's 2021 IRP (all of which have now been approved by the Commission) were found to be lower than the capital (including mandated environmental technology), O&M, fuel, and emissions costs that would have to be incurred to continue operating the existing coal fleet over the long-term. Mr. Augustine's 2022 analysis filed in Cause No. 45772 is attached as OUCC Request 9-004 Confidential Attachment A.

Since 2022, as noted above, NIPSCO has received approval for a CPCN (Cause No. 45947) to complete the gas CT Project to be located at the site of the soon-to-be retired Schahfer plant. In anticipation of filing this electric rate base rate case, NIPSCO updated certain assumptions from its 2018 IRP with additional information that is now known today to confirm the preferred portfolio remained the least-cost option for customers. This refreshed 2024 analysis, with refreshed assumptions under the 2018 IRP's portfolio construct, is attached as OUCC Request 9-004 Confidential Attachment B.

OUCC Request 9-004 Confidential Attachments A and B reflect estimated costs to continue to operate Schahfer Units 17 and 18 through 2035 (Confidential Attachment A) and in perpetuity (Confidential Attachment B). Those estimated costs are as of a point in time and reflect information known at the time each analysis was conducted. The methodologies associated with these analyses are generally consistent with

NIPSCO's 2018 and 2021 IRPs, which were viewed favorably by stakeholders and the IURC.

Pulled from the 2024 analysis, OUCC Request 9-004 Confidential Attachment C shows NIPSCO's calculation of what it considers a reasonable estimate, based on presently available information, of the total investment cost necessary to operate Schahfer Units 17 and 18 through 2027. This calculation relies on assumptions related to costs to install required environmental controls and to continue the ongoing replacement, repair, and operation of equipment installed when the units were placed in service in the mid 1980s. As discussed below and importantly, this estimate does not incorporate costs associated with the feasibility of reversing course on a long-planned-for plant retirement within the next twelve months without compromising service reliability and the delivery of other generation projects, already found to be reasonable and necessary. For example, by significantly jeopardizing construction of the approved CT Project that provides needed load-following generation, NIPSCO's compliance with now-approved MISO resource adequacy and capacity accreditation rules would be upended. NIPSCO would need to install a wastewater treatment system and convert the Unit 14 and 15 bottom ash handling system by the December 31, 2025 compliance date established in Schahfer's IDEM water permit (National Pollutant Discharge Elimination System ("NPDES") permit), which is not feasible, and which would be required to operate Schahfer Units 17 and 18 *for one day* beyond 2025. Operating Schahfer Units 17 and 18 beyond 2025 would expose NIPSCO to financial risk; NIPSCO has not estimated the cost of that risk but expects it would be substantial.

Based on the above, as shown in OUCC Request 9-004 Confidential Attachment C, NIPSCO calculates that operating Schahfer Units 17 and 18 beyond 2025 would require more than $1 billion of additional investment through 2027.

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OUCC Request 9-005:
Please confirm the estimated annual O&M costs for NIPSCO to continue operating Schafer Units 17 and 18 after December 31, 2025.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: See the "2024 Coal Assumptions" tab in OUCC Request 9-004 Confidential Attachment B.

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OUCC Request 9-006:
Please confirm the estimated cost and lead time needed to install wastewater treatment systems on Schahfer Unit 17 and on Schahfer Unit 18 if these units continued to operate past December 31, 2025.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary, and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: See NIPSCO's response to OUCC Request 9-004. See OUCC Request 9-006 Confidential Attachment A for NIPSCO's estimate to install a wastewater treatment system on Schahfer Units 17 and 18. NIPSCO estimates it would take approximately three to four years to install a wastewater treatment system on Schahfer Units 17 and 18. It is not feasible to install a wastewater treatment system on Schahfer Units 17 and 18 by the December 31, 2025 compliance date.

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OUCC Request 9-007:
Please confirm the estimated annual O&M cost to operate wastewater treatment systems on Schahfer Units 17 and on Schahfer Unit 18 if they continued to operate past December 31, 2025.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: See NIPSCO's responses to OUCC Request 9-004 and 9-006. See OUCC Request 9-007 Confidential Attachment A.

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OUCC Request 9-008:
Please confirm the estimated cost and lead time necessary to install dry bottom ash handling on Schahfer Unit 17 and on Schahfer Unit 18 if the units continued to operate past December 31, 2025.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: See NIPSCO's response to OUCC Requests 9-004, 9-010, and 9-011.

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OUCC Request 9-009:
Please confirm the estimated annual O&M cost for the dry bottom ash handling system for Schahfer Units 17 and 18 if the units continued to operate past December 31, 2025.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
See objection.

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OUCC Request 9-010:
Please confirm whether Schahfer Units 17 and 18 would be able to use the dry bottom ash handling system previously built to serve Schahfer Units 14 and 15. Please explain why or why not.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: Yes. See OUCC Request 9-010 Confidential Attachment A.

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OUCC Request 9-011:
If it is possible to use the Schafer Units 14 and 15 dry bottom ash handling system, please confirm the cost and lead time necessary to re-route Schahfer Units 17 and 18's bottom ash wastewater stream to this system.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: See NIPSCO's response to OUCC Request 9-010.

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OUCC Request 9-012:
Please confirm whether it is feasible to construct a Coal Combustion Residuals (CCR) Rule-compliant lined surface impoundment to hold Schahfer Units 17 and 18 bottom ash wastewater. Please explain why or why not.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request is vague and ambiguous as the term "feasible" is undefined. For purposes of this Request, NIPSCO interprets "feasible" to mean it is practically capable of being carried out.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: It is not feasible to construct a CCR Rule-compliance lined surface impoundment to hold Schahfer Units 17 and 18 bottom ash wastewater. As described in the Schahfer Waste Disposal Area Part A Demonstration Annual Progress Report dated October 26, 2024:[1] > NIPSCO previously evaluated the feasibility of constructing new alternative CCR and non-CCR waste management options on-Site, even though RMSGS will cease all coal-fired generation in just over one more year (i.e., no later than December 2025). As in 2020 and confirmed in 2022 (Demonstration Addendum 2), due to Site-specific factors (e.g., space limitations, shallow depth to groundwater and thus the inability to reasonably achieve the 40 CFR §257.60(a) five-foot separation from the upper limit of the uppermost aquifer), permitting and/or regulatory hurdles including permit application review timeframes, potential supply chain issues relative to equipment and construction materials availability, and building timeframes, *construction of new alternative management facilities is infeasible*. (emphasis added)

[1] Available at https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/ccr/r.m.-schahfer/r.m.-schahfer-generating-station-closure-and-post-closure-care/nipsco-llc-rmsgs-wda-part-a-demonstration-annual.pdf?sfvrsn=31fae551_3

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OUCC Request 9-013:
Please confirm the estimated cost and lead time necessary to construct a CCR Rule-compliant lined surface impoundment to hold Schahfer Units 17 and 18's bottom ash wastewater.
Objections:
NIPSCO objects to this Request on grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
See objection. See also NIPSCO's response to OUCC Request 9-012.

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OUCC Request 9-014:
Please confirm the estimated annual O&M cost associated with a CCR Rule-compliant lined surface impoundment serving Schahfer Units 17 and 18 if NIPSCO were to continue their operation after December 31, 2025.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
See objection. See also NIPSCO's response to OUCC Request 9-012.

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OUCC Request 9-015:
Please confirm whether Schahfer Units 17 and 18 currently have dry fly ash handling systems.
Objections:
Response:
Yes. Schahfer Units 17 and 18 currently have dry fly ash handling systems.

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OUCC Request 9-016:
Please confirm the estimated annual disposal cost for CCR material from Schahfer Units 17 and 18 if these units were to continue operating after December 31, 2025.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
See objection.

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OUCC Request 9-017:
Please confirm the estimated cost lead time necessary to construct and install Selective Catalytic Reduction (SCR) systems on Schahfer Units 17 and 18.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: See OUCC Request 9-017 Confidential Attachment A.

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OUCC Request 9-018:
Please confirm the estimated annual O&M cost to operate SCRs on Schahfer Units 17 and 18.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
See objection.

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OUCC Request 9-019:
Please confirm the estimated cost and lead time necessary to convert Schahfer Units 17 and 18 to co-fire on natural gas.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: NIPSCO completed one estimate of the cost to "fully convert" Schahfer Units 17 and 18 to gas-fired units as part of its 2018 IRP for the portfolio titled "6b," which assumed a 2023 conversion of the units to natural gas. The conversion cost and ongoing FOM and CapEx costs are highlighted in the "CapEx" and "FOM" tabs in OUCC Request 9-019 Attachment A. Additional details around the assumptions for these costs can be found in Section 4.10.5 of the 2018 IRP report (pg. 63-64).[1] "Fully converting" to natural gas would not include the costs of coal handling and ash disposal, which would be included in "co-firing" the unit. "Fully converting" assumes a 15% capacity de-rate (when the analysis was conducted in 2018). NIPSCO has not studied the current lead time to convert Schahfer Units 17 and 18 to natural gas.

[1] https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2018-nipsco-irp.pdf?sfvrsn=83256851_16.

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OUCC Request 9-020:
Please confirm the approximate date when Schahfer Units 17 and 18 last had a major turbine overhaul or replacement. Please explain.
Objections:
Response:
The last major turbine overhauls for Units 17 & 18 at Schahfer were: Unit 17 – Fall of 2017 Unit 18 – Fall of 2018

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OUCC Request 9-021:
If Schahfer Units 17 and 18 were to continue to operate after December 31, 2025, please identify the major repairs, maintenance, or replacement of equipment NIPSCO anticipates would need to be completed. Please provide the cost associated with each such project.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: See NIPSCO's response to OUCC Request 9-004.

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OUCC Request 9-022:
If NIPSCO were to add required environmental controls and investments to continue operating Schahfer Units 17 and 18 after December 31, 2025, please identify the cost NIPSCO anticipates Schahfer Units 17 and 18 would need to be offered into the MISO energy market to break even.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing. NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request is overly broad and unduly burdensome in that this Request is not limited to a specific time. NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: NIPSCO's latest dispatch analysis with Schahfer Units 17 and 18 operating beyond 2025 was conducted as part of Mr. Augustine's 2022 analysis included in OUCC Request 9-004 Confidential Attachment A.

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OUCC Request 9-023:
Please provide the last two analyses NIPSCO conducted, including any internal analyses not publicly shared to date, demonstrating whether retiring Schahfer Units 17 and 18 by the end of December 31, 2025, is NIPSCO's most economical option available.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: See NIPSCO's response to OUCC Request 9-004.

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OUCC Request 9-024:

Please confirm all additional investments that will be necessary to continue Michigan City Unit 12's operation if it retired January 1, 2032, instead of December 31, 2028. Please also provide the related estimated capital and annual O&M costs associated with each investment.

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request seeks documents or information that are beyond the scope of this proceeding and are not relevant to the subject matter of this proceeding and are therefore not reasonably calculated to lead to the discovery of admissible evidence, as it seeks information beyond the Forward Test Year in this Cause.

NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.

Response:

Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response:

NIPSCO last evaluated operation of Michigan City until 2032 in its 2021 IRP (https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2021-nipsco-integrated-resource-plan.pdf?sfvrsn=f6ae0251_6). In that analysis, NIPSCO evaluated four different retirement dates for MC12, including 2032, 2028, 2026, and 2024. NIPSCO concluded that earlier retirement continued to show cost savings and that a retirement date between 2026-2028 was preferred (no later than 2028). Please refer to the 2021 IRP pages 214-218: section 9.1.7 "Evaluation of Each Existing Fleet Portfolio – Results" and section 9.1.8 "Existing Fleet Analysis Scorecard Summary" for the details on the portfolios that were analyzed. Portfolio 1 included a 2032 retirement date for Michigan City Unit 12 and had a higher customer cost than portfolios 2, 3, 4, and 6, which all assumed earlier retirement dates for Michigan City Unit 12. The "Retirement CapEx" and "Retirement FOM" tabs of Confidential Appendix D to the 2021 IRP contain the annual capital and FOM projections associated with a 2032 retirement date for Michigan City Unit 12 as of the time of the 2021 analysis.

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No updated analysis has been performed on Michigan City Unit 12 with a specific 2032 retirement date since 2021 IRP.

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OUCC Request 9-025:
Please confirm all additional investments that will be necessary to continue Michigan City Unit 12's operation if Michigan City Unit 12 retired after January 1, 2032, but before January 1, 2039. Please also provide the estimated capital and O&M costs associated with each investment.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks documents or information that are beyond the scope of this proceeding and are not relevant to the subject matter of this proceeding and are therefore not reasonably calculated to lead to the discovery of admissible evidence, as it seeks information beyond the Forward Test Year in this Cause. NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: NIPSCO has not evaluated a retirement date for Michigan City 12 after January 1, 2032, but before January 1, 2039. In order to operate Michigan City Unit 12 after 2032 and retire before 2039, NIPSCO would need to retrofit the facility to co-fire with natural gas by 2030 to comply with the EPA Emission Guidelines for Existing Steam Generating Units. NIPSCO has not evaluated the cost of retrofitting the Michigan City facility to co-fire with natural gas.

Cause No. 46120
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Ninth Set of Data Requests

OUCC Request 9-026:
Please confirm the estimated cost and lead time necessary to convert Michigan City Unit 12 to co-fire on natural gas if the unit were to continue operation past 2028.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks documents or information that are beyond the scope of this proceeding and are not relevant to the subject matter of this proceeding and are therefore not reasonably calculated to lead to the discovery of admissible evidence, as it seeks information beyond the Forward Test Year in this Cause. NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: NIPSCO has not evaluated any costs or lead times associated with converting Unit 12 to run on natural gas or co-fire with coal and natural gas.

Cause No. 46120
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Ninth Set of Data Requests

OUCC Request 9-027:
Please confirm the approximate date when Michigan City Unit 12 last had a major turbine overhaul or replacement. Please explain.
Objections:
Response:
The last turbine major overhaul for Unit 12 at Michigan City Generating Station was in the Spring of 2019.

Cause No. 46120
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Ninth Set of Data Requests

OUCC Request 9-028:
If Michigan City Unit 12 were to retire January 1, 2032, instead of the end of 2028, please confirm the major repairs, maintenance, or replacement of equipment that would need to be completed. Please provide the cost associated with each such project.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks documents or information that are beyond the scope of this proceeding and are not relevant to the subject matter of this proceeding and are therefore not reasonably calculated to lead to the discovery of admissible evidence, as it seeks information beyond the Future Test Year in this Cause. NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: See NIPSCO's response to OUCC Request 9-024.

Cause No. 46120
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Ninth Set of Data Requests

OUCC Request 9-029:
If Michigan City Unit 12 were to retire after January 1, 2032, but before January 1, 2039, please confirm the major repairs, maintenance, or replacement of equipment that would need to be completed. Please provide the cost associated with each project.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks documents or information that are beyond the scope of this proceeding and are not relevant to the subject matter of this proceeding and are therefore not reasonably calculated to lead to the discovery of admissible evidence, as it seeks information beyond the Forward Test Year in this Cause. NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: See NIPSCO's response to OUCC Request 9-025.

Cause No. 46120
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Ninth Set of Data Requests

OUCC Request 9-030:
Please confirm whether the Schahfer landfill currently has sufficient disposal capacity to support extending the retirement date of Michigan City Unit 12 until January 1, 2032. If not, please confirm and explain whether it is possible to expand the current landfill and state the expected cost of such an expansion.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
The Schahfer landfill does not have sufficient disposal capacity to support extending the retirement date of Michigan City Unit 12 until January 1, 2032. Expanding the current landfill could be possible, but no analysis has been performed as to the expected cost of such an expansion.

Cause No. 46120
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Ninth Set of Data Requests

OUCC Request 9-031:
Please confirm whether the Schahfer landfill currently has sufficient disposal capacity to support extending the retirement date of Michigan City Unit 12 until January 1, 2039. If not, please confirm and explain whether it is possible to expand the current landfill and state the expected cost of such an expansion.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: The Schahfer landfill does not have sufficient disposal capacity to support extending the retirement date of Michigan City Unit 12 until January 1, 2039. Expanding the current landfill could be possible, but no analysis has been performed as to the expected cost of such an expansion.

Cause No. 46120
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Ninth Set of Data Requests

OUCC Request 9-032:
Please provide the last two analyses NIPSCO conducted, including any internal analyses not publicly shared, showing whether retiring Michigan City Unit 12 by December 31, 2028, is the most economical option available.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: See NIPSCO's response to OUCC Request 9-004.

Cause No. 46120
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Ninth Set of Data Requests

OUCC Request 9-033:
Since its previous Integrated Resource Plan (IRP), please confirm whether NIPSCO has analyzed the cost to extend the retirement dates of Schahfer Unit 17, Schahfer Unit 18, and/or Michigan City Unit 12. If so, please provide any and all such analyses.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: See NIPSCO's responses to OUCC Requests 9-004, 9-023, and 9-032.

Cause No. 46120
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Ninth Set of Data Requests

OUCC Request 9-034:
Please confirm whether NIPSCO anticipates significant load growth within the next 10 years from data centers or other large load customers. If yes, please quantify this load growth and the expected annual growth, by year, over the next 10 years.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks publicly available information. NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request seeks documents or information that are beyond the scope of this proceeding and are not relevant to the subject matter of this proceeding and are therefore not reasonably calculated to lead to the discovery of admissible evidence.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: In its 2024 Integrated Resource Plan ("IRP"), NIPSCO is analyzing five (5) different scenarios that are intended to evaluate various "future states of the world". This includes the "Domestic Resiliency (DR)" scenario, which evaluates high load from new large loads and industrial onshoring MISO-wide, as well as higher electric vehicle penetration. The IRP includes 2,600 MW of data center load in its Reference case portfolios by 2035 (details are listed in the public slides), and it also includes an Emerging High Load sensitivity with 8,600 MW of data center load through 2035 (details are also listed in the public slides). The public stakeholder materials for the 2024 IRP are available online at: https://www.nipsco.com/our-company/about-us/regulatory-information/irp. NIPSCO would specifically direct attention to the following slides: - Stakeholder Meeting #2, slides 17 to 25, 46 to 50, 57 to 60, 133 to 136, - Stakeholder Meeting #3, slides 14 to 15 - Stakeholder Meeting #4, slides 21 to 54 - Stakeholder Meeting #5, slides 64 and 67 to 69 for the high load sensitivity

Cause No. 46120
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Ninth Set of Data Requests

The IRP represents a snapshot in time based on what is known today. NIPSCO will continue to evaluate future states of the world, including data center and large load customers, in future IRPs.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-29
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-30

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 133
Department Press Release on Centralia Order

An official website of the United States government

Energy Secretary Ensures Washington Coal Plant Remains Open to Ensure Affordable, Reliable and Secure Power Heading into Winter

U.S. Secretary of Energy Chris Wright today issued an emergency order to ensure Americans in the Northwestern region of the United States have access to affordable, reliable and secure electricity heading into the cold winter months.

Energy.gov

December 17, 2025
2 min

Emergency order addresses critical grid reliability issues, lowering risk of blackouts and ensuring affordable electricity access

WASHINGTON—U.S. Secretary of Energy Chris Wright today issued an emergency order to

ensure Americans in the Northwestern region of the United States have access to affordable, reliable and secure electricity heading into the cold winter months. The order directs TransAlta to keep Unit 2 of the Centralia Generating Station in Centralia, Washington available to operate. Unit 2 of the coal plant was scheduled to shut down at the end of 2025. The reliable supply of power from the Centralia coal plant is essential for grid stability in the Northwest. The order prioritizes minimizing the risk and costs of blackouts.

"The last administration's energy subtraction policies had the United States on track to experience significantly more blackouts in the coming years — thankfully, President Trump won't let that happen," said **Energy Secretary Wright**. "The Trump administration will continue taking action to keep America's coal plants running so we can stop the price spikes and ensure we don't lose critical generation sources. Americans deserve access to affordable, reliable, and secure energy to heat their homes all the time, regardless of whether the wind is blowing or the sun is shining."

According to DOE's Resource Adequacy Report(link is external), blackouts were on track to potentially increase 100 times by 2030 if the U.S. continued to take reliable power offline as it did during the Biden administration.

The North American Electric Reliability Corporation (NERC) determined in its 2025-2026 Winter Reliability Assessment that the WECC Northwest region is at elevated risk during periods of extreme weather, such as prolonged, far-reaching cold snaps.

This order is in effect beginning on December 16, 2025, and continuing until March 16, 2026.

Background:

The NERC Winter Reliability Assessment(link is external) warns that "extreme winter conditions extending over a wide area could result in electricity supply shortfalls." With winter electricity demand continuing to rise, peak demand in the U.S. increased by 2.5% since last winter.

###

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Just Launched: A Critical Materials Career Map
December 17, 2025

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Energy Department Grants Woodside Louisiana LNG Project Additional Time to Commence Exports

December 16, 2025

Tags:

- Strengthen Grid Reliability and Security
- Emergency Response

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Equal Employment Opportunity

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-29
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-30

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 134
MISO Manual on Resource Adequacy

Manual No. 011

Business Practices Manual

RESOURCE ADEQUACY

Disclaimer

This document is prepared for informational purposes only, to support the application of the provisions of the Tariff and the services provided thereunder. MISO may revise or terminate this document at any time at its discretion without notice. While every effort will be made by MISO to update this document and inform its users of changes as soon as practicable, it is the responsibility of the user to ensure use of the most recent version of this document in conjunction with the Tariff and other applicable documents, including, but not limited to, the applicable NERC Standards. Nothing in this document shall be interpreted to contradict, amend, or supersede the Tariff. MISO is not responsible for any reliance on this document by others, or for any errors or omissions or misleading information contained herein. In the event of a conflict between this document, including any definitions, and either the Tariff, NERC Standards, or NERC Glossary, the Tariff, NERC Standards, or NERC Glossary shall prevail. In the event of a conflict between the Tariff and the NERC Standards, or NERC Glossary, the Tariff shall prevail until or unless the Federal Energy Regulatory Commission ("FERC") orders otherwise. Any perceived conflicts or questions should be directed to the Legal Department.

Revision History

Doc Number	Description	Revised by:	Effective Date
BPM-011-r31	Included language related to Final PRMR allocation process in Section 5.6 and other editorial changes Updated PRA Formulations in Appendix M	MISO Staff	FEB-21-2025
BPM-011-r30	Annual Review Complete including UCAP/ISAC ratio related process improvement, GADS events/performance submission, timeline change for multiple process such as state notifying MISO on utilizing their own PRM, full responsibility transactions, confirm/convert SAC etc, edits for RBDC (MRI/RBDC curve development, RBDC opt out process, PRMR determinations for PRA and settlements etc)	MISO Staff	OCT-01-2024
BPM-011-r29	Annual Review Complete. Edits include GVTC test extension updates, 31-day rule and ZRC replacement updates, LMR and ER registration updates, OY CIL CEL removal Appendix K timeline updates and Attachment Y updates to schedule 53 resources and the UCAP/ISAC ratio process and timeline.	N. Przybilla	OCT-01-2023
BPM-011-r28	Clarify and add additional context surrounding ZRC replacement and the 31-day outage rule in section 6.4 while ensuring language is consistent with Module E-1 of the MISO Tariff.	N. Przybilla	May-31-2023
BPM-011-r27	Updates to all sections to facilitate the implementation of seasonal auctions & seasonal accreditation (FERC Docket No. ER22-495). Includes updates from annual BPM review	MISO Staff	October-31-2022
BPM-011 r26	Replacement of 4.2.12 Battery Storage Accreditation with Electric Storage Resource. Add Electric Storage Resource to section 4.2.8. BTMG Qualification Requirements. Update Appx K. Correct Appendix N – Demand and Energy Forecast Characteristics.	M. Guerriero	AUG-15-2022
BPM-011-r25	2021 Annual review complete. Edits include: Hybrid resources, detail added to States establishing PRM, detail for 90/120 day outages, clarification for BTMG wind UCAP, Updated to	MISO Staff	JUL-01-2021

	reference new DSRI tool instead of MCS, updated RAN related LMR accreditation (ER20-1846), new DR Test Deferral process, Battery Storage accreditation, reorganized Appx I XEFORd, added Process Load reporting section, updated App K Timeline.		
BPM-011-r24	2020 Annual review complete. Edits include new Appendix W (DR LOLE), Deliverable ICAP (ER20-1942, ER20-2005), GVTC testing clarification, ZDB example, and other minor clarifications.	G. Alexander	DEC-15-2020
BPM-011-r23	Revisions to address treatment of resources on long term outage which FERC approved under Dock No. ER20-129-000.	T. Bachus	MAR-31-2020
BPM-011-r22	2019 Annual Review Complete. Edits include: general clean up, ER19-2559 (PRA Process Timeline) & ER18-2363 (Locational Filing), web links, ER UCAP intermittent qualification, Appx R CONE calculation, removing Att W (ER19-650 RAN Phase 1 LMR filing) by imbedding language into applicable LMR sections.	E. Thoms	OCT-1-2019
BPM-011-r21	Added LMR Registration FAQ to address ER19-650-000	E. Thoms	FEB-20-2019
BPM-011-r20	Multiple updates. Revisions supporting changes to the out-year transfer study process. Additional revisions to support the Module E-1, Locational Tariff update which created External Resource Zones and several other changes.	M. Sutton	NOV-01-2018
BPM-011-r19	Revisions to Section 4.2.8 clarifying language when a Qualifying Facility participates as a BTMG. Addition of SER Type II resource. Annual Review completed.	J. Harmon	SEP-28-2018
BPM-011-r18	Annual Review Complete Includes revisions to Section 4.2.8.5 clarifying deliverability options for BTMG.	J. Harmon	JAN-22-2018
BPM-011-r17	Annual Review Complete	J. Harmon	AUG-25-2017
BPM-011-r16	Several updates. Updated Wind UCAP values; added section regarding Solar capacity credit; Revised provisions for Zonal Deliverability Benefit; Inclusion of Suspended resources in the PRA; Retail Choice coincident load forecast reporting process. Annual Review completed.	J. Harmon	JUL-15-2016

BPM-011-r15	Annual Review completed. Included Inter-zonal replacement, sub regional constraints in PRA, PRMR and LCR relationship, external resource and host BA qualification requirements, GVTC deferral, and refueling versus repowering. Additions to section 5.2.1 for Local Resource Zone reevaluation process and Generation Limited Transfers	J. Milli / M. Sutton / S. Quadri / J. Cole / R. Westphal	SEP-01-2015
BPM-011-r14	Annual Review completed. Remove netting of Demand Response. Update SFT and Transfer Analysis provisions.	J. Milli	SEP-01-2014
BPM-011-r13	Updated LRZ map, timeline, and added catastrophic outage provisions	C. Clark	JAN-01-2014
BPM-011-r12	Annual review and updated to reflect Tariff orders	C. Clark	AUG-01-2013
BPM-011-r11	Updated to reflect Module E-1-1 Tariff	C. Clark	OCT-01-2012
BPM-011-r10	Updated GVTC language for Hydro and ROR.	C. Clark	SEP-28-2012
BPM-011-r9	Annual Review completed and Updated Registration tables and added new section for qualifying PPAs.	C. Clark	APR-15-2012
BPM-011-r8	MISO Rebranding Changes JUL-19-2011	G. Krebsbach	JUN-13-2011
BPM-011-r8	Annual Review and added Dispatchable Intermittent Resource, minor clarifications	C. Clark	JUN-13-2011
BPM-011-r7	Updated UCAP calculations for plan year 2011/2012, undated must offer provisions, updated External Resources cross-border deliverability provisions, updated minor clarifications	M. Heraeus / C. Clark	Dec-1-2010
BPM-011-r6	Corrected errors and added “must offer” language and Units with Low Service Hours	M. Heraeus / C. Clark	JUN-1-2010
BPM-011-r5	Corrected errors and inadvertent omissions	M. Heraeus	MAR-3-2010
BPM-011-r4	Resource Adequacy Improvements Tariff Filing updates. Changed numbering to BPM -011	K. Larson	DEC-21-2009
TP-BPM-003-r3	Removed stakeholder comments from section 6.4 that were provided during drafting of TP-BPM-003-r2. Amended section 4.4.3.14.4.3.1.	T. Hillman	JUN-01-2009
TP-BPM-003-r2	Revised to reflect the December 28th, 2007 (ER08-394) filing and subsequent Commission required compliance filings through May 2009 to revise Module E-1 to comprehensively address long-term Resource Adequacy Requirements	T. Hillman	JUN-01-2009
TP-BPM-003-r1	Revised to reflect Open Access Transmission, Energy and Operating Reserve Markets Tariff for	J Moser	JAN-06-2009

	the Midwest ISO, Inc. (Tariff) relating to implementation of the Day-Ahead and Real-Time Energy and Ancillary Services Markets and to integrate proposed changes to the Balancing Authority Agreement.		
TP-BPM-003	Updated template	J. Moser	APR-01-2008
N/A	Section 3.2.1 Determination of Requirements – Non-valid statements were removed. Section 3.2.3 Default Requirements – Minor revisions were made for clarification. Section 3.2.4 Compliance with the Midwest ISO Requirements – Paragraph on after-the-fact ECAR “must offer” compliance was removed. Section 4.1 Commercial Pricing Node Load Forecast – Minor revisions were made for clarification. Section 5.2.1 Procedure for Designating a Network Resource for Resource Adequacy Purposes – LD Contracts bullet updated to reflect FERC Order 890. Section 5.2.3 Designating Network Resources External to the Midwest ISO – The second bullet point was revised for clarification. Section 5.3 Determination of Compliance with Network Resource Requirements – This section was deleted. Section 5.4 (5.3) Network Resource Must Offer Requirement – Paragraph on after-the-fact ECAR “must offer” compliance was removed. Section 5.5 Financial Transmission Rights – This section was deleted. Section 5.6 (5.4) Updating Network Resource Designations – RE references have been updated to reflect the current NERC Regions. Section 6.1.3 Liquidated Damage and Similar Contracts – Entire section updated to reflect FERC Order 890. Section 6.1.4 Hubbing Transactions – This section was deleted. Section 8 Data Requirements – Entire section updated to reflect FERC order 890		DEC-12-2007

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1 Introduction

This introduction to the Midcontinent Independent System Operator, Inc. (MISO) *Business Practices Manual (BPM)* for Resource Adequacy Requirements includes basic information about this BPM and the other MISO BPMs. The first section (Section 1.1) of this Introduction provides information about the MISO BPMs. The second section (Section 1.2) is an introduction to this BPM. The third section (Section 1.3) identifies other documents in addition to the BPMs, which can be used by the reader as references when reading this BPM.

1.1 Purpose of the MISO Business Practices Manuals

The BPMs developed by MISO provide background information, guidelines, business rules, and processes established by MISO for the operation and administration of the MISO markets, provisions of transmission reliability services, and compliance with the MISO settlements, billing, and accounting requirements. A complete list of MISO BPMs is available for reference through MISO's website.

1.2 Purpose of this Business Practices Manual

This Resource Adequacy Business Practices Manual describes MISO's and other entities' roles and responsibilities related to maintaining Resource Adequacy, which is ensuring that Load Serving Entities (LSE) serving Load in the MISO Region have sufficient Planning Resources to meet their anticipated peak Demand requirements plus an appropriate reserve margin.

The Resource Adequacy BPM will conform and comply with MISO's Energy Markets Tariff, NERC operating policies, and the applicable Regional Entity (RE) reliability principles, guidelines, and standards to facilitate administration of efficient Energy Markets.

This document benefits readers who want answers to the following questions regarding the Resource Adequacy Requirements (RAR).

- How is Resource Adequacy determined?
- How do the multiple state jurisdictions relate regarding Resource Adequacy Requirements (RAR)?
- What are the responsibilities of the different entities regarding Resource Adequacy?
- How are specific resources identified and qualified, including contracted resources, for Resource Adequacy purposes?
- What is a Zonal Resource Credit (ZRC) and how can it be used to comply with RAR?
- What are the deliverability requirements for Planning Resources?

- How are Demand Response Resources (DRR Type I and Type II) incorporated in the Resource Adequacy process?
- How does an LSE comply with its obligations under the changes to Module E-1 of the Tariff?
- What are the procedures for participating in Planning Resource Auctions?
- What are the settlement provisions for the Planning Resource Auctions?
- What are the procedures for tracking and settling retail and wholesale customer switches?

This document provides the necessary detail to aid a MISO Market Participant's (MP) understanding of its primary responsibilities and obligations to the reliable operation of MISO's Balancing Authority Footprint, as a result of MISO's Resource Adequacy Requirements.

1.3 References

Other reference information related to this document includes:

- MISO BPMs
- MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff
- NERC – Resource and Transmission Adequacy Recommendations, dated June 15, 2004
- Federal Energy Regulatory Commission (FERC) Order Nos. 890, Order 890 - A, and Order 890 -B.
- Module E Capacity Tracking (MECT) tool Users Guide
- LOLE Study Reports
- Wind & Solar Capacity Credit Report
- PowerGADS User's Manual
- CIL/CEL Study Reports

2 Overview of Resource Adequacy

Achieving reliability in bulk electric systems requires, among other things, that the amount of resources exceeds customer Demand by an adequate margin. The margins necessary to promote Resource Adequacy needs to be assessed on both a near-term operational basis and on a longer-term planning basis.

The focus of Resource Adequacy is on the longer-term planning margins that are used to provide sufficient resources to reliably serve Load on a forward-looking basis. In the real-time operational environment, resources committed through the Resource Adequacy Requirements have a capacity obligation to be available to meet real-time customer Demand and contingencies. Therefore, Planning Reserve Margins (PRMs) must be sufficient to cover:

- Planned maintenance
- Unplanned or forced outages of generating equipment
- Deratings in the capability of Generation Resources and Demand Response Resources
- System effects due to reasonably anticipated variations in weather
- Load Forecast Uncertainty

2.1 Planning Reserve Margin Requirement Overview

Each LSE's total obligation will be referred to as the Planning Reserve Margin Requirement (PRMR). Coincident Peak Demand forecasts are submitted by LSEs using a 50%/50% forecast (50% probability the forecast will be over, and 50% probability the forecast will be under, the projected peak Demand) which will include distribution losses. An LSE's Initial Planning Reserve Margin Requirement (Initial PRMR) is described in Section 3 (Establishing Initial Planning Reserve Margin Requirements) of this BPM.

2.2 Planning Resources Overview

The resources used to achieve long-term Resource Adequacy are called Planning Resources, and consist of Capacity Resources, Load Modifying Resources and Energy Efficiency Resources. The relationships and key attributes of the Planning Resource types are as follows:

- Capacity Resources consist of electrical generating units, stations known as Generation Resources, External Resources (if located outside of the MISO Balancing Authority Area), Electric Storage Resources (ESR), Hybrid Resources, and resources that can be dispatched to reduce Demand known as Demand Response Resources that participate in the Energy and Operating Reserves Market

and are available during Emergencies. Thermal Generation Resources are accredited based on the methodology described in Appendix Y (Schedule 53 Resources). Wind Resources will be accredited based on the ELCC study that MISO conducts. Non-wind intermittent generation resources will be accredited based on historical performance during the critical hours within each Season, where new resources will receive the class average for that resource type until enough historical data is accrued. Non-Schedule 53 Capacity Resources that report to GADS are quantified by applying seasonal forced outage rates to Installed Capacity (ICAP) values to calculate the Seasonal Accredited Capacity (SAC) for the resource.

- Load Modifying Resources (LMR) include Behind-the-Meter Generation (BTMG) and Demand Resources (DR) which are available during capacity and transmission Emergencies declared by MISO if used to meet Module E-1 requirements.
- Energy Efficiency Resources include installed measures on retail customer facilities that achieve a permanent reduction in electric Energy usage while maintaining a comparable quality of service.

A Market Participant (MP) can use Capacity Resources, LMRs, and Energy Efficiency Resources, up to their SAC values, to comply with their Resource Adequacy Requirements via a Fixed Resource Adequacy Plan or Reliability Based Demand Curve Opt Out (RBDC Opt Out) as described in Section 5.3 (Pre-PRA arrangement of capacity scheduling) of this BPM, or through self-scheduling their Zonal Resource Credits in the Planning Resource Auction(s) (PRA) as detailed in Section 5.5.6 (Resource Offers) of this BPM. A Market Participant can also sell ZRCs from Capacity Resources, LMRs, and Energy Efficiency Resources bilaterally before the Planning Resource Auction(s) or offer them in the Planning Resource Auction(s) as described in Section 5.5 (Planning Resource Auction) of this BPM.

MISO will determine Seasonal Accredited Capacity (SAC) values for all qualified Capacity Resources, Load Modifying Resources and for all Energy Efficiency Resources for each Season within the Planning Year.

2.3 Resource Adequacy Requirements Overview

Planning Resources that clear the Planning Resource Auction(s) (PRA) or that are designated in a Fixed Resource Adequacy Plan (FRAP) or RBDC Opt Out will be obligated to provide capacity in the Day-Ahead and Real Time Markets (DA/RT) for each Season cleared within the Planning Year unless replaced by another Planning Resource, as per Module E-1 Section 69A.3.1.h. Capacity Replacement Non-Compliance Charge(s) (CRNCC) may be applicable as

per Module E-1 Section 69A.3.1h. Load Serving Entities (LSEs) that serve Load during the Planning Year will be obligated to pay for capacity from Planning Resources in the PRA pursuant to the relevant Auction Clearing Price (ACP) for the Local Resource Zone (LRZ) where the Load is located unless the Planning Resource was designated in a FRAP or RBDC Opt Out.

LSEs that have a Planning Reserve Margin Requirement (PRMR) will be obligated to procure capacity equal to their Final PRMR pursuant to the relevant ACP for the LRZ where they have PRMR unless, and to the extent that the LSE meets its Final PRMR via a FRAP or RBDC Opt Out per Section 5.3 of this BPM, or unless and to the extent that the LSE chooses to reduce its Final PRMR that is cleared in a given auction(s) by electing to pay the Capacity Deficiency Charge per Section 5.7 of this BPM.

2.4 Settlements/Performance Requirements Overview

The seasonal Planning Reserve Margin Requirement (PRMR) obligations of LSEs will be established for each Season of the Planning Year and will be settled based upon the applicable Planning Resource Auction(s) (PRA) clearing price for an LSE's Final Planning Reserve Margin Requirement, unless covered by a FRAP or RBDC Opt Out, or unless the LSE elects to pay the Capacity Deficiency Charge. Once each planning period begins, LSEs and MPs will have the corresponding charges and credits from each applicable PRA included on their daily settlement statements for all loads and Planning Resources cleared in a PRA as documented in further detail in the Market Settlements BPM.

LMRs with ZRCs that either cleared the PRA or were used in a FRAP or RBDC Opt Out will have a performance obligation to be available during system Emergencies per section 4.2.7 (Demand Resource Qualification Requirements) iof this BPM.

3 Establishing Initial Seasonal Planning Reserve Margin Requirements

3.1 Overview

The Initial seasonal Planning Reserve Margin Requirement (PRMR) is the number of MWs in ZRCs required to meet an LSE's Resource Adequacy Requirements (RAR). The RAR is established to ensure that LSEs have enough Planning Resources to reliably serve load for the applicable Seasons.

The Initial seasonal PRMR is expressed in the following equation per Load Serving Entity (LSE) per Local Resource Zone (LRZ)

$$Initial\ PRMR_{LRZ} = \sum_{LBA}[(CPDf_{LBA} - FRP_{LBA} + FRS_{LBA}) \times (1 + TL_{LBA}\%) \times (1 + PRM_{RTO})]$$

Where attributes are seasonal for the following:
Initial $PRMR_{LRZ}$ = Initial Planning Reserve Margin Requirement per LRZ
$CPDf_{LBA}$ = Coincident Peak Demand forecast per LBA
FRP_{LBA} = Full Responsibility Purchase per LBA
FRS_{LBA} = Full Responsibility Sale per LBA
$TL_{LBA}\%$ = Transmission Loss Percentage of LBA
PRM_{RTO} = Planning Reserve Margin in Unforced Capacity set by LOLE Studies

3.1.1 Agency Contracts Supporting Resource Adequacy Requirements

An LSE may contract with other entities to comply with RAR. The contracted entity may perform functions on behalf of the applicable LSE including, but not limited to, submitting the LSE's forecasted CPD forecast or share of CPD forecast.

Each individual LSE is ultimately responsible for conformance with the RAR, even if the LSE enters a contract with a third party acting on its behalf. If requested by MISO, each LSE that contracts with another entity to comply with any part of the Resource Adequacy Requirements must notify MISO of the arrangement. The LSE must provide MISO with the name of the organization representing them, primary and alternate contact information for the individuals representing them, and the scope of responsibilities the contracted entity will provide.

3.1.2 Validation of Firm Transmission Service for Load

Each LSE shall document, as described in Module B – Transmission Service, to MISO that the LSE has obtained sufficient firm Transmission Service to serve its load for each Season in the Planning Year. Load not served by Network Integrated Transmission Service (NITS) must have Firm Point-to-Point Transmission Service or a firm Grandfathered Agreement (GFA), when applicable—however, Demand does not require firm MISO Transmission Service when the LSE meets its Initial PRMR using its own Behind-the-Meter Generation (BTMGs), Demand Resources (DRs), and Energy Efficiency Resources, and does not use the MISO Transmission System to serve such Demand.

Additionally, Energy Resource Interconnection Service (ERIS) requires a completed firm Transmission Service Request (TSR) submitted through OASIS OATI that has been approved by the Generation and Interchange team at MISO in order to be considered towards deliverability that is used to convert Seasonal Accredited Capacity (SAC) to Zonal Resource Credits (ZRCs). This information will be entered into the MECT on the Convert SAC screen by Market Participants (and in the Registrations screen, if applicable).

3.2 Demand and Energy Forecasts

MISO collects a variety of load forecasts for Resource Adequacy and other planning processes via the MECT tool. This section describes each of these forecasts and what entity is responsible for providing them. Please See Appendix O for the list of parties responsible for reporting Demand and Energy forecasts.

Demand and Energy forecasts that are not subject to retail choice load switching should be reported by the respective LSE. Demand and Energy forecasts that are subject to retail choice load switching should be reported by the respective Electric Distribution Company (EDC). The EDC calculates a Peak Load Contribution (PLC) MW value for each retail choice LSE that represents a share of the EDC's Initial PRMR. If an LSE disagrees with their PLC value calculated by their EDC, the LSE will work with its EDC to revise the PLC prior to the final EDC forecast submission deadline. See Appendix K for all Demand and Energy forecast deadlines.

All Demand (Energy) forecasts must reflect a 50% probability that the Demand (Energy) will not exceed the forecasted Demand (Energy) for the relevant time period. Any manual or ex-post adjustments to the forecasts derived from the LSE's chosen forecasting method that are offered

due to catastrophic event impacts (such as COVID-19) must be supported analytically and quantitatively.

For a detailed description of each forecast's characteristics refer to Appendix N.

3.2.1 Non-Coincident Peak Demand and Energy for Load Forecasts

Non-Coincident Peak Demand and Energy for Load forecasts are collected for the purposes of facilitating FERC Form 714 and NERC Modeling Data and Analysis (MOD) Standards reporting along with other planning processes at MISO.

The MISO FTR Administration team uses the Non-Coincident Peak forecast value for the upcoming planning year in the annual Auction Revenue Rights (ARR) allocation process. This forecast should not include transmission losses or Grandfathered Agreements (GFAs) but should include Demand Resources and Behind-The-Meter-Generation (BTMG). Load served by GFAs is reported separately via the same MECT section.

Please refer to NERC's Reliability MOD Standards for a complete definition for the non-Coincident Peak Demand forecast and FERC's Form 714 for the Energy for Load forecast. Below are general guidelines; if a conflict should arise between the guidelines below and the respective NERC standards documents, defer to the latter.

The Non-Coincident Peak Demand and Energy for Load forecasts are reported on a monthly basis for forecast years 1 and 2 and on a seasonal basis for forecast years 3 through 10.

Seasons for the purposes of these forecasts are defined as shown below:

Summer: June through August
Fall: September through November
Winter: December through February
Spring: March through May

For seasonal reporting of the Non-Coincident Peak Demand forecast, the single highest peak hour during the Season should be reported in MW. The ARR allocation section of the Non-Coincident Peak Demand Forecast submission screen, should be calculated and submitted on an annual peak for a given Planning Year for use in the FTR annual Auction Revenue Rights process. For Energy for Load forecasts, the summation of each month or season's Energy for load (GWh) should be reported as appropriate.

For all forecasts submitted, each LSE shall ensure that it counts its customer Demand once and only once.

Non-Coincident Peak Demand and Energy for Load forecast must be reported in the MECT by 11:59 pm EST on November 1 prior to the Planning Year.

For a detailed description of each forecast's characteristics refer to Appendix N.

3.2.2 Coincident Peak Demand Forecast

The seasonal Coincident Peak Demand forecasts (CPD forecast) are used as the basis for determining each LSE's seasonal obligation. The seasonal CPD forecasts shall be based upon considerations including, but not limited to, average historical weather conditions, economic conditions and expected Load changes (addition or subtraction of Demand).

For a detailed description of each forecast's characteristics refer to Appendix N.

A document describing the desired approach to be used by LSEs in preparing the seasonal CPD forecasts, the information required in each annual filing, and the process used in reviewing the CPD Forecasts can be found on MISO's website: Peak Forecasting Methodology Review Whitepaper. This document was written for when LSEs submitted an annual Coincident Peak Forecast, but the same methodology described in the paper can be performed at a seasonal level.

The seasonal CPD forecasts must be provided for each Asset Owner/LBA combination. Providing the CPD forecasts by Asset Owner is required by MISO's settlements process. Reporting by LBA allows MISO to apply the appropriate seasonal Transmission Losses towards the Initial PRMR and Final PRMR calculation. Seasonal Transmission Losses will be made available on the public website by MISO for each LBA. For more information on Transmission Losses see Appendix L.

The CPD forecasts must be reported via the MECT tool by 11:59 EST on November 1 prior to the Planning Year.

The CPD forecasts are reported differently in non-retail choice and retail choice areas as described in the following subsections.

3.2.3 Forecast Reporting

LSEs with Demand and Energy that are not subject to retail choice load switching are required to provide MISO with Demand and Energy forecasts no later than 11:59 p.m. EST on November 1 each year, for the following Planning Year. The seasonal CPD forecasts must be reported for each Asset Owner by LBA.

LSEs with Demand and Energy that is subject to retail choice load switching are not required to provide MISO with Demand and Energy forecasts. Electric Distribution Companies (EDCs) are responsible for submitting forecasts in areas that have Demand and Energy that is subject to retail choice load switching.

EDCs are defined as the company that distributes electricity to retail customers through distribution substations and/or lines owned by the company. The EDC of a retail choice area provides MISO with a seasonal peak forecasted Demand coincident with MISO's seasonal peak and must provide this data no later than 11:59 p.m. EST on November 1 prior to the Planning Year.

EDCs must provide both MISO and the respective retail choice LSEs with each retail customer's initial seasonal Peak Load Contribution (PLC) in the EDC's service territory no later than 11:59 p.m. EST on December 15 prior to the Planning Year.

All new EDCs are required to work with the MISO Client Services and Readiness department (https://help.misoenergy.org/) to set up access to the MECT tool and identify the relationships between the EDC and the LSEs in the EDC area. A Help Center ticket will need to be created to detail the access and relationship additions for the new EDC. The MISO Client Services and Readiness team will provide the new EDC with the required registration forms. Once the EDC setup is completed, all MPs with commercial pricing nodes participating in the retail choice load switching program are required to provide the name of the EDC where the commercial pricing node is located.

3.2.3.1 Provider of Last Resort

The Provider of Last Resort (POLR) will be responsible for meeting any Initial PRMR from Demand left unclaimed by retail choice LSEs in the EDC service territory. The Transmission Provider will work with the POLR and EDC to ensure that the POLR will serve any remaining Demand that is not allocated to LSEs.

3.2.4 Wholesale Load Customers

To ensure wholesale customers are accounted for, LSEs serving wholesale customers during the prompt Planning Year must include the Demand and Energy attributed to those wholesale customers in their Demand and Energy forecasts by 11:59 p.m. EST on November 1 prior to the Planning Year via the MECT tool.

An LSE that has previously served a wholesale customer and does not intend on serving that customer for the prompt Planning Year may or may not be required to report that customer in their forecasts.

Case 1: LSE knows the entity that will serve the wholesale customer next Planning Year:
In this case, the existing LSE is not responsible for submitting the Energy or Demand attributed to the wholesale customer in their forecasts. However, they must state the entity responsible for serving the customer in their supporting documentation.

Case 2: LSE does not know who will serve the wholesale customer next Planning Year:
In this case, the existing LSE is responsible for submitting the Energy or Demand attributed to the wholesale customer in their forecasts.

MISO will work with the wholesale customer regarding their forecasts and contact the wholesale customer to determine who the responsible LSE is. Once the responsible LSE is identified, MISO will transfer the Demand from the old LSE to the new LSE prior to the Planning Resource Auction.

3.2.5 Review of CPD Forecasts

Starting November 1, MISO will begin reviewing all forecasts and a randomly chosen set of supporting documentation submitted by LSEs and EDCs in order to give all parties adequate time to resolve any identified forecasting issues with MISO. The review will focus on whether the forecast methodology adequately and reasonably forecasts peak Demand, Energy, and/or Demand reduction capability of the submitting entity. The forecast review process will be completed no later than March 1 of each year prior to the annual PRA. If necessary, MISO may develop the required seasonal CPD forecasts for any Market Participants serving Load in the Transmission Provider Region or serving Load on behalf of a Load Serving Entity or other Market Participants that do not submit CPD forecasts and supporting documentation by the November 1 deadline.

3.3 Full Responsibility Transactions

Full Responsibility Transactions (FRT) are referenced differently depending on which side of the transaction is being addressed. The sale side of an FRT is called a Full Responsibility Sale (FRS) and the purchase side is called a Full Responsibility Purchase (FRP). Both the FRS and FRP are a transfer of Demand. As a result, the seasonal obligation (Initial PRMR and Final PRMR) calculation will reflect the associated transfer of transmission losses and PRM. FRTs may only be entered for Demand that is not subject to retail choice load switching.

The FRS results in an increase in Demand and FRP results in a decrease in Demand. This can be interpreted as the purchaser paying the seller to take on Demand and its associated seasonal Initial PRMR. This transfer of Demand also results in a transfer of the associated transmission losses and PRM.

- The seller of an FRS is contractually obligated to deliver power and Energy to the purchaser with the same degree of reliability as provided to the seller's own native load. With Full Responsibility Service to an LSE within MISO's Region, sellers are responsible for all of that LSE's Initial PRMR associated with the sale.

  Example:

  Asset Owner MM1:
  Seasonal CPDf = 10 MW
  Seasonal PRM = 6.2%
  Seasonal Transmission Loss % = 2%
  Asset Owner MM1 is the Buyer of the FRT for the total amount of 5 MW
  MM1's Initial PRMR = (10 – 5) * (1 + 0.062) * (1 + 0.02) = 5.4 MW

  Asset Owner SS2:
  Seasonal CPDf = 20 MW
  Seasonal PRM = 6.2%
  Seasonal Transmission Loss % = 2%
  Asset Owner SS2 is the Seller of the FRT for the total amount of 10 MW
  SS2's Initial PRMR = (20 + 10) * (1 + 0.062) * (1 + 0.02) = 32.5 MW

  Asset Owner BB3:
  Seasonal CPDf = 50 MW

Seasonal PRM = 6.2%
Seasonal Transmission Loss % = 2%
Asset Owner BB3 is the Buyer of the FRT for the total amount of 5 MW
Asset Owner BB3 is the Seller of the FRT for the total amount of 10 MW
BB3's Initial PRMR = (50 – 5 + 10) * (1 + 0.062) * (1 + 0.02) = 59.6 MW

The LSE (purchaser) may contract with other entities (sellers) to be responsible for capacity payments based upon the ACP for all or part of its load delivered to the purchaser through an FRP/FRS agreement. Each purchaser and seller must agree on which of their transactions are to be reported as an FRP/FRS. If the purchaser and seller cannot agree upon whether a particular transaction is an FRP/FRS agreement, then either party may invoke the dispute resolution procedures in the Tariff. FRP/FRS agreements are treated effectively like a transfer of forecasted Demand and the associated Initial PRMR from one LSE to another. An LSE with an FRP agreement is required to input the forecasted Coincident Peak Demand information for the transferred Demand into the MECT. An MP with a FRS agreement is required to meet the RAR obligation derived from the Demand as though it was their load, as described in Section 3. If the seller under an FRP/FRS agreement is not an LSE subject to the MISO Tariff, then the purchaser under an FRP/FRS agreement will remain responsible for any capacity payments associated with the FRP/FRS agreement.

If the seller under an FRS/FRP agreement is not an LSE subject to the MISO Tariff ("non-jurisdictional"), then the purchaser who is responsible for any RAR deficiencies may coordinate with the non-jurisdictional party to ensure that any RAR obligations associated with transferred Demand are met. A purchaser may request that the seller communicate the proper validations and confirmations to the purchaser or confirm validation of RAR obligations in the MECT to the purchaser. Such purchaser also can request that MISO coordinate with the non-jurisdictional party to intermediate the exchange of information from the seller to the purchaser. Such coordination will not relieve the purchaser from their responsibility for any RAR deficiencies associated with the FRP/FRS agreement.

The LSE with the FRS is responsible for compliance with LSE requirements. The obligation to serve the load is shifted but the obligation to forecast the Demand remains with the original LSE (purchaser). Both the purchasing and selling parties will be required to enter and verify the FRT into the MECT Full Responsibility Transaction screen. The parties must enter an FRT into the MECT along with documentation detailing their contract between the purchasing and selling

parties to enable MISO to track the load and capacity obligations shift. This must be done by the fifth business day of February and the settlement will be between LSEs for all FRTs.

The Initial PRMR cannot be a negative number as a result of the FRT.

3.4 Planning Reserve Margin

This section describes the Loss of Load Expectation (LOLE) study process used by MISO to establish the Planning Reserve Margin (PRM) for each Season of the prompt MISO Planning Year. A MISO Planning Year runs from June 1 through May 31.

3.4.1 Determination of Seasonal Planning Reserve Margin

MISO will perform probabilistic analyses annually to establish the system-wide seasonal PRMs. This probabilistic analysis will utilize a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations. Additionally, MISO will perform probabilistic analyses to establish the seasonal Local Reliability Requirements (LRRs) for each Local Resource Zone. MISO will publish the results by November 1 preceding the applicable Planning Year.

The LOLE study shall be consistent with Good Utility Practice, the reliability requirements of the Regional Entities (RE), and applicable states in the MISO Region. The PRM analyses shall consider factors including, but not limited to: the Generator Forced Outage rates of Capacity Resources, Generator Planned Outages, expected performance of Load Modifying Resources (LMRs), Intermittent Resources, Energy Efficiency Resources, load forecast uncertainty, and the Transmission System's import and export capabilities with external systems. The seasonal PRMs that are calculated in the LOLE probabilistic modeling software are determined on an ICAP and UCAP basis. The preliminary $PRMR_{ICAP}$ values are the sum of the ICAP ratings of the resources utilized in the simulation to achieve the reliability criteria. Similarly, the sum of the UCAP ratings of these same resources utilized in the simulation to achieve the reliability criteria is the total UCAP-rated MW needed, or the preliminary $PRMR_{UCAP}$ Values. PRMR values are finalized after MISO has received the updated LSE-submitted load forecasts on November 1 and validated the load forecasts.

MISO will calculate and publish on its website the estimated seasonal PRM for each of the nine subsequent Planning Years, to provide information for long-term resource planning, without establishing any enforceable specific resource planning reserve requirements.

See the Resource Adequacy page on MISO's public website for current and previous LOLE study reports.

3.4.2 LOLE Analysis

MISO will determine the appropriate PRM for each Season of the applicable Planning Year based on the probabilistic analyses of being able to reliably serve MISO's forecasted seasonal Coincident Peak Demand. This probabilistic analysis will utilize a LOLE study which assumes that there are no internal transmission limitations.

MISO's LOLE study will first calculate the annual PRM such that the summation of LOLE across the year is one (1) day in ten (10) years, or 0.1 day per year. The minimum PRM requirement will be determined through LOLE analyses by either adding a negative output unit with no outage rates, or by adding increments of a positive output combustion turbine (CT) Planning Resource with nominal capacity values that correspond with the most recent annual calculation of Cost of New Entry (CONE) as described in Section 6.3 and that have class average outage rates, until a 0.1 day per year solution is reached.

A minimum of 0.01 day per Season LOLE will be used to calculate the seasonal PRMs and LRRs in Seasons with less than 0.01 day per year LOLE risk upon the annual summation of LOLE reaching the 0.1 day per year reliability criteria.

The LOLE model will initially be run with no adjustments to the capacity. If the LOLE in a given Season is less than the reliability criteria day per year for that Season, a negative output unit with no outage rates will be added until the LOLE reaches the reliability criteria for that Season. This is comparable to adding Coincident Peak Demand. If the LOLE is greater than the reliability criteria, proxy units based on a unit of typical size and outage rates will be added to the model until the LOLE reaches the reliability criteria.

MISO will also determine the Local Reliability Requirement (LRR) for each LRZ consistent with the LOLE achieving 0.1 day per year for each LRZ. The minimum amount of capacity above seasonal Coincident Peak Demand required to meet the reliability criteria of a 0.1 day per year LOLE value will be utilized to establish the system-wide seasonal PRMs. The minimum amount of capacity above the seasonal Zonal Coincident Peak Demand required to meet the reliability criteria of a 0.1 day per year LOLE value will be utilized to establish the seasonal LRR for each LRZ. When determining LRRs, risk-deficient Seasons will have a minimum reliability criteria of 0.01 LOLE per Season.

3.4.3 Loss of Load Expectation (LOLE) Working Group

MISO establishes seasonal Unforced Capacity requirements applicable in the Planning Resource Auction (PRA) based on LOLE probabilistic analyses conducted by MISO Resource Adequacy and in coordination with members of the LOLE Working Group (LOLEWG). The duties of the working group are to help guide MISO in implementing the study methods outlined in this section. The analyses will conform to the Electric Reliability Organization (ERO) standards, including those established by applicable Regional Entities for reliability and resource adequacy. The LOLEWG will review and provide recommendations to MISO on the methodology and input assumptions to be used in performing the LOLE analyses, as well as reviewing the results of the LOLE analyses and related sensitivity cases. MISO will be the entity ultimately responsible for conducting the LOLE study and determining the seasonal PRMs, except as set forth in Section 3.4.5.

3.4.4 Generator Outage Data for LOLE Study

The probabilistic study will use a LOLE model capable of sequential Monte Carlo simulation. Primary inputs are the generation data submitted to MISO through the PowerGADS tool and forecasted Demands provided as described above in this Section 3. If applicable to the generator type, Asset Owners are obligated to report outage event data as well as Generator Verification Test Capacity (GVTC) for Generation Resources and External Resources through the PowerGADS tool in the MISO Market Portal. Annualized planned outage rates and seasonal forced outage rates are developed for each applicable resource from the submitted outage event data and, together with the capabilities of each resource, are the key generator inputs to the LOLE model. Outage parameters for the LOLE model are established using outage event data from the past five calendar years, as submitted to PowerGADS.

The LOLE study will account for all system-wide forced outage causes captured in the EFORd metric. The EFORd term is defined as:

> Equivalent Forced Outage Rate while in Demand (EFORd): A measure of the probability that a generating unit will not be available for the applicable Season due to forced outages or forced deratings when there is Demand on the unit to generate.

More information on EFORd calculations can be found in Appendix I of this BPM.

3.4.5 State Authority to Set PRM

The only entity other than MISO that may establish a PRM for any Season during the Planning Year is a state regulatory authority regarding those regulated entities under their jurisdiction. If a state regulatory authority establishes a minimum seasonal PRM for the LSEs under their jurisdiction, then that state-set seasonal PRM would be adopted by MISO for jurisdictional LSEs in such state. Other entities, such as reserve sharing groups or NERC regional entities, do not have the authority to establish a seasonal PRM under Module E-1. MISO will translate any state-set seasonal PRM into the same terms as MISO's seasonal PRM (e.g., utilizing a UCAP basis) to facilitate comparison and compliance with PRMR.

MISO will perform the Loss of Load Expectation (LOLE) study to establish the seasonal PRM and publish the results by November 1 preceding the Planning Year. State regulatory authorities choosing to instead elect a state set seasonal PRM must notify MISO in writing by December 1 for the upcoming PRA. The notice shall be from an authorized representative of the state regulatory authority and include the seasonal PRMs, a list of those LSEs to which the seasonal PRMs apply, and a statement that the entities to which the seasonal PRM applies have been duly notified. In scenarios where an LSE crosses state boundaries and one of the states opts to set its own seasonal PRM, the state regulatory authority must work with the impacted LSEs to submit to MISO the pro-rata distribution of seasonal Coincident Peak Forecasts and seasonal Zonal Coincident Peak Forecasts among the states.

Any disputes regarding the applicability of the seasonal PRM information submitted by a state regulatory authority and an affected entity shall be resolved in accordance with applicable dispute resolution measures established by the state regulatory authority. If the state regulatory authority makes any changes to information initially submitted to MISO as a result of such a dispute, the changed information shall be submitted to MISO by the state regulatory authority on or before December 31. If no such changes are submitted, the original information submitted by the state regulatory authority will be used by MISO.

MISO shall update the MECT with the state-set seasonal PRM by January 31.

4 Qualifying and Quantifying Planning Resources

4.1 Overview

This section identifies the qualification requirements for each type of Planning Resource.

All Planning Resources that qualify will have a SAC value determined by MISO. The benefits of SAC include:

- Fair recognition of the contribution each unit provides towards Resource Adequacy;
- Market signals that will promote generating unit availability performance; and in turn, the improved system availability will promote improved regional Resource Adequacy; and
- Supporting bilateral trades by recognizing the SAC value of each resource, while shifting the resource performance risk to owners of Planning Resources, where such risk more properly belongs.

Planning Resources consist of Capacity Resources, Load Modifying Resources, and Energy Efficiency Resources. Capacity Resources consist of Generation Resources, Electric Storage Resources, External Resources, and Demand Response Resources. Load Modifying Resources consist of Behind the Meter Generation and Demand Resources. Energy Efficiency Resources are resources registered with MISO that permanently reduce electricity Demand. A Hybrid Resource may also qualify as a Planning Resource to the extent that such Hybrid Resource is a Generation Resource or Capacity Resource.

Capacity Resources backed by behind-the-meter-generation that have met all requirements to supply capacity in the MISO Resource Adequacy construct will have SAC MWs calculated based on data submitted by the Asset Owner, as described in the Appendix H - Non-Schedule 53 Seasonal Accredited Capacity (SAC) Calculations for Planning Resources - of this document. BTMG, DR, Energy Efficiency Resources, and External Resources must follow the registration procedures documented in the applicable subsections of this document to be eligible to supply capacity in the MISO Resource Adequacy construct.

Generation Resources backed by behind-the-meter-generation that have not provided at least one Season of historical performance data will have their SAC calculated for them after they are registered in MISO's Commercial Model, provided that the Resource meets the Capacity Resource Module E-1 requirements. Planning Resources that are pseudo-tied between MISO Local Balancing Areas will be modeled in the Local Resource Zone based on the LBA in which they are physically located. The following table outlines the relationship and key attributes of the Planning Resource types that are committed to providing capacity.

	Planning Resource				
	Capacity Resource		Load Modifying Resource		Energy Efficiency Resource
	Generation, ESR, and External	Demand Response Resources	BTMG	Demand Resource	
Capacity Verification	X	X	X	X	X
Must Offer	X	X			
GADS Data Entry	X	X	X		
Must Respond to Emergency Operating Procedures	X	X	X	X	

4.2 Planning Resources

4.2.1 Generation Resource, but not Dispatchable Intermittent Resource or Intermittent Generation

4.2.1.1 *Qualification Requirements*

Generation Resources may qualify as Capacity Resources provided that:

- They are registered with MISO as documented in the Market Registration BPM.
- Generation Resources must be deliverable to Load within MISO's Region. The deliverability of Generation Resources to Network Load within MISO's Region shall be determined by System Impact Studies pursuant to the Tariff that are conducted by MISO, which consider, among other factors, the deliverability of aggregate resources of Network Customers to the aggregate of Network Load. Generation Resources that pass the deliverability test receive Network Resource Interconnection Service.
- Generation Resources that do not pass the deliverability test may procure firm Transmission Service (or utilize a GFA) in conjunction with Energy Resource Interconnection Service (ERIS) to meet the deliverability requirements.
    - Firm Transmission Service must either be a Firm Point-to-Point (PTP) Transmission Service Request (TSR) or a Firm Network Integration Transmission Service (NITS) Scheduling Right (SR).
        - NITS SRs should reference the OASIS NITS Application number and Resource Name used in the SR.

  - Firm transmission service (PTP TSR or NITS SR) must cover the entire applicable Season within the Planning Year in total or in aggregate and be submitted in the MECT. The resource is only deliverable to the LBA identified in the Firm Transmission study that grants the NITS SR or PTP TSR.
- Generation Resources with ERIS may participate in MISO's Interim Deliverability Study process as described in BPM-015. The following generic parameters apply for the Interim Deliverability Study:
  - MISO may grant conditional NRIS applicable for the next Planning Year
  - MISO may grant conditional ERIS applicable for the next Planning Year
  - MISO may grant conditional External-NRIS (E-NRIS) applicable for the next Planning Year.
  - MISO may implement a Quarterly Operating Limit (QOL) on a portion of a Generation Resource due to transmission study overloads. MW amount subject to QOL can qualify as capacity in the PRA. The MW amount subject to QOL is not required to procure replacement capacity if the QOL is reduced in a subsequent MISO quarterly study.
- Generation Resources with a Provisional Interconnection Agreement are not qualified to participate in the PRA.
- Generation Resources that were accepted by the Transmission Provider and confirmed by a Network Customer as a designated Network Resource under the OASIS reservation process in place prior to either the initial effective date of the Energy Market in 2005 or that Transmission Owner's integration date are considered as deliverable.
  - This may include Generation Resources that were issued 'local' NRIS through a Generator Interconnection Agreement consistent with Module E-1 Section 69.3.1.g paragraph v. In such instances, 'local' NRIS is processed in similar fashion as ERIS for the purposes of demonstrating deliverability for participation in the Planning Resource Auction. As with resources with ERIS, firm Transmission Service must be demonstrated to cover the entire auction period for the level of participation desired in order to qualify for participation in the PRA.
- Internal purchase power agreements (PPAs) will not be qualified by MISO.
- Generation Resources greater than or equal to 10 MW (based on Generation Verification Tested Capacity (GVTC)) must submit their Generator Availability Data System (GADS) data (including, but not limited to, NERC GADS) into the MISO PowerGADS database through the MISO Market Portal. Quarterly GADS Event and

Performance Data must be submitted by the end of the month following the quarter (April for Q1, July for Q2, October for Q3, and January for Q4). The submitted data must have passed Level 2 Validation without any errors. Units that fail to submit Level 2 Validated quarterly GADS data will be disqualified for participation in the PRA.

- Generation Resources less than 10 MW based upon GVTC are not required to report their GADS data.
- Generation Resources less than 10 MW based upon GVTC that begin reporting GADS data must continue to report GADS data each Planning Year.
- The seasonal XEFORd for new Generation Resources in service less than one full Season will be the seasonal EFORd class average for the resource type. A Generation Resource will use the class average value until 3 consecutive seasonal months of data is available. Forced outage rates are used for the capacity accreditation of non-Schedule 53 Generation Resources.
- Generation Resources that have been retired prior to the Planning Year will not qualify as a Planning Resource.
- Generation Resources that are in approved “Suspension” status qualify as a Planning Resource through the ICAP Deferral process.
- If Generation Resources used to meet Resource Adequacy Requirements retire or suspend during the Planning Year, they must be replaced effective with their change of status date. Generation Resources with approved “Suspension” status must participate as a Planning Resource in the next Planning Year subject to provisions regarding physical withholding in Module D of the Tariff.
- Generation Resources that plan to retire during the Planning Year will be subject to test for Physical Withholding.
- Generation Resources that are or plan to be suspended will be subject to test for Physical Withholding.
- Generation Resources that have been designated as a System Support Resource (SSR) may participate in the PRA.
- Generation Resources must demonstrate capability on an annual basis as described below.
- Generation Resources undergoing conversion to natural gas are not required to submit GVTC prior to returning. Changes in performance will be reflected in the resource’s rolling XEFORd.

When to Perform and Submit a Generation Verification Test Capacity (GVTC)

- Generation Resources, External Resources, ESR, Demand Response Resources backed by behind the meter generation, or Behind the Meter Generation (BTMG) that qualified as Planning Resources for the current Planning Year must submit their GVTC no later than October 31 in order to qualify as a Planning Resource for the upcoming Planning Year. GVTC can be completed by completing a real power test or based on operational data. The GVTC must be completed during the test period of September 1 through August 31 prior to the upcoming Planning Year.
- A real power test is required to demonstrate a modification that increases the rated capacity of a unit, and a revised GVTC should be submitted to MISO no later than March 1 prior to the Planning Year. The initial GVTC, even if a Planning Resource is unable to test and the GVTC is 0, must be submitted by October 31 prior to the Planning Year.
- A real power test is required when returning from a suspended state and the GVTC must be submitted to MISO. A real power test is required when any unit returns to service in MISO after an absence (including but not limited to, catastrophic events, or a period during which it was not qualified as a Planning Resource under Module E-1).
- A real power test is required for Planning Resources in an approved "Suspension" status. If a Planning Resource is unable to complete a real power test, the MP responsible for that Planning Resource must include this item, including timing and cost requirements, when requesting a facility specific reference level.

The GVTC for a new or returning Non-Intermittent Generation resource is due by March 1 prior to the Planning Year unless the GVTC has been deferred via the ICAP Deferral process as described in Section 4.5. See Appendix J **– GVTC Testing Requirements**.

GVTC Test Extension Request

A Market Participant for a Generation Resource required to submit GVTC results must use Reasonable Efforts to submit GVTC results by October 31 prior to the upcoming Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the Generation Resource by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline, estimated seasonally corrected GVTC values, and an expected completion date prior to the upcoming Planning Year. An extension may also be requested for re-testing and submitting after the October 31 deadline. The

estimated seasonally corrected GVTC values are only an estimate to be used in initial SAC posting and the actual test results will be used for the final SAC posting. The Transmission Provider will review each extension request on a case-by-case basis to determine whether to approve or deny the request to extend the GVTC deadline. Denial of an extension will not preclude the Market Participant for the Generation Resource from utilizing the ICAP Deferral process. Test results for Approved GVTC Test Extension Requests must be submitted by January 15 prior to the upcoming Planning Year.

Reporting is accomplished through MISO's PowerGADS reporting system as described in the Net Capability Verification Test User Manual.

4.2.1.2 *SAC Determination*

The SAC values for a Generation Resource are based on an evaluation of the type and volume of interconnection service, GVTC values, the XEFORd value of non-Schedule 53 Generation Resources as described in Appendix H – Non-Schedule 53 Seasonal Accredited Capacity (SAC) Calculations for Planning Resources and Appendix I – XEFORd Calculation, and SAC value for Schedule 53 Resources as applicable and described in Appendix Y – SAC Calculations for Schedule 53 Resources.

Generation Resources relying either fully or in part on Energy Resource Interconnection Service (ERIS) coupled with firm Transmission Service to demonstrate deliverability must procure firm Transmission Service up to the Resource's ICAP level in order to receive their full SAC allocation.

If a Generation Resource's procured firm Transmission Service coupled with ERIS is less than the Generation Resource's ICAP value, the SAC allocation would be pro-rated based on Tariff Module E-1 Section 69A.4.5.

The SAC methodology is implemented to address the fact that not all Generation Resources contribute equally to Resource Adequacy. By adjusting the capacity rating of a unit based on its availability, SAC provides a means to recognize the relative contribution that each resource makes towards Resource Adequacy. When the PRM requirement is similarly adjusted by the weighted average EFORd of all the pooled resources, the generating units with better than average availability will reflect higher values than units with below average availability.

In order for a Generation Resource to convert its entire calculated Total SAC into Zonal Resource Credits, the Generation Resource must be fully deliverable up to its ICAP. Deliverability is determined by any combination as outlined in Module E-1 Section 69A.3.1.g of the Tariff.

If a Generation Resource is not fully deliverable up to its ICAP, the resource will be eligible to convert a value less than the Total SAC into Zonal Resource Credits as outlined in Appendix H – Non-Schedule 53 Seasonal Accredited Capacity (SAC) Calculations for Planning Resources, as well as in Appendix Y – SAC Calculations for Schedule 53 Resources.

4.2.1.3 *Intermittent Generation and Dispatchable Intermittent Resources - Qualification Requirements*

Intermittent Generation and Dispatchable Intermittent Resources are subclasses of Generation Resources and may qualify as Capacity Resources if they meet the same qualification requirements in Sec. 4.2.1.1 Qualification Requirements and the alternate GADS reporting procedure as described below:

For existing Intermittent Generation and Dispatchable Intermittent Resources (eg. run-of-river hydro, solar, biomass), Market Participants must supply MISO with a minimum of one entire Planning Year of hourly net output data for each season in which the resource would be accredited.

For existing Intermittent Generation and Dispatchable Intermittent Resources not classified as run-of-river hydro or wind, Market Participants may submit up to three (3) Planning Years of hourly net output data, for a total of 9 months considered for each seasonal lookback period, during typical seasonal peak hours, where the typical seasonal peak hours are hours ending in 15, 16, and 17 EST for the Summer, Fall and Spring Seasons, and hours ending in 8, 9, 19, and 20 EST for the Winter Season. Seasonal accreditation for existing Intermittent Generation and Dispatchable Intermittent Resources not classified as run-of-river hydro or wind is determined as an average of the hourly net output.

For Intermittent Generation and Dispatchable Intermittent Resources classified as run-of-river hydro, Market Participants may submit up to fifteen (15) Planning Years of hourly net

output data, for a total of 45 months considered for each seasonal lookback period, during typical seasonal peak hours, where the typical seasonal peak hours are hours ending in 15, 16 and 17 EST for the Summer, Fall and Spring Seasons, and hours ending in 8, 9, 19 and 20 EST for the Winter Season. Seasonal accreditation for fun-of-river hydro resources is determined as a median of the provided hourly net output.

For resources on qualified extended outage where data does not exist for some or all of the previous historical seasonal months, a minimum of 30 consecutive days' worth of historical net output data during the relevant typical seasonal peak hours, must be provided prior to participating in the PRA.

New Intermittent Generation or Dispatchable Intermittent Resources that do not have a minimum of 30 consecutive days' worth of seasonal historical operating data during the typical seasonal peak hours may participate in the PRA and will receive class average accreditation values if the resource will be in operation by the start of a Season in the applicable Planning Year.

4.2.1.4 *Dispatchable Intermittent Resources and Intermittent Generation Resource - SAC Determination*

The Seasonal Accredited Capacity (SAC) for Intermittent Generation and Dispatchable Intermittent Resources will be determined by MISO based on historical performance, availability, and type and volume of Interconnection Service. Examples of SAC calculations for these resources can be found in Appendix V – Solar and Run-of-River Hydro Capacity Credit.

Intermittent Generation and Dispatchable Intermittent Resources that are powered solely by wind will have their SAC values determined based on Interconnection Service volumes and their respective wind capacity credit established via seasonal Effective Load Carry Capacity (ELCC) analyses as described in Appendix A – Wind Capacity Credit.

1.1.1.1.1 4.2.1.5 Wind Capacity Credit

MISO calculates specific wind capacity credit (%) for each wind resource and applies it to its registered maximum capability (MW) in the Commercial Model or its registered Capacity (MW) through the LMR or External Resource registration process. MISO uses historical wind

availability information to calculate a seasonal Effective Load Carrying Capacity (ELCC) to determine a wind capacity credit. Wind capacity credits are determined for each individual wind resource based on its average capacity factor during MISO's top eight (8) coincident peaks that occurred during the Season for the previous three Planning Years.

A new wind resource with no commercial operation history during the Season will receive a wind capacity credit equivalent to the MISO system wide wind capacity credit from the seasonal Effective Load Carrying Capacity (ELCC) analyses for their initial Planning Year, and thereafter metered data will be used to calculate its future resource-specific wind capacity credit.

If an existing wind resource has no historical metered data available, or was inoperable for a Season, then the existing wind resource will receive a seasonal capacity credit of 0%.

An increase in unit capacity for Intermittent Generation and Dispatchable Intermittent Resources that are solely powered by wind after the SAC values have been established will require written notification from the Market Participant to a member of the Resource Adequacy department to update the values. This notification is due by March 1 prior to the applicable Planning Year.

BTMG wind will have their SAC values determined from their historical net output during periods of MISO system peak Demand for the three Planning Years prior.

For more information regarding the methodology for calculating wind capacity credits, see Appendix A – Wind Capacity Credit of this BPM and MISO's wesbite (misoenergy.org / Planning / Resource Adequacy / PRA Documents / select the appropriate Planning Year) for the Wind and Solar Capacity Credit Report. Additionally, Appendix H – Seasonal Accredited Capacity (SAC) Calculations for Planning Resources details the determination of convertible SAC using the deliverability-adjusted capacity factor.

1.1.1.1.2 4.2.1.6 Solar Capacity Credit

Solar resources will have their SAC values determined based on the three (3) most recent Planning Years of historical average net output during typical seasonal peak hours, where the typical seasonal peak hours are hours ending in 15, 16, and 17 EST for the Summer, Fall and Spring Seasons, and hours ending in 8, 9, 19 and 20 EST for the Winter Season.

Solar resources that have been upgraded or returning from extended outages shall submit all operating data for the prior Season with a minimum of 30 consecutive days to have their capacity registered with MISO.

Solar esources with less than 30 days of metered values would receive seasonal class accreditation for their initial Planning Year in operation. Seasonal class accreditation for a new solar resource in the Summer, Fall, and Spring Seasons is 50% and 5% for the Winter Season. Refer to Appendix V - Solar and Run-of-River Hydro Capacity Credit for additional examples and determination of convertible SAC.

4.2.2 Use Limited Resources

4.2.2.1 *Use Limited Resources – Qualification Requirements*

Use Limited Resources are defined as Generation Resources or External Resource(s), that due to design considerations, environmental restrictions on operations, cyclical requirements (such as the need to recharge or refill), or for other non-economic reasons, are unable to operate continuously, but are able to operate for a minimum set of consecutive operating hours. A Capacity Resource may be defined as a Use Limited Resource if it:

- Is capable of providing the Energy equivalent of its claimed Capacity for a minimum of at least four (4) continuous hours each day across MISO's peak;
- Notifies MISO of any outage (including partial outages) and the expected return date from the outage;
- Demonstrates GVTC and submits the results to MISO;
- Is a dispatchable resource(s) in which the unit(s) have physical limitations;
- Identifies the resource as use limited when registering the asset, subject to MISO approval.
    - MISO will review the conditions of the asset or PPA to determine if the resource qualifies as a Use Limited Resource.
    - MISO will consider how the resource has historically operated and any proposed changes in its operation to determine if the resource qualifies as a Use Limited Resource.

Use Limited Resources are a subclass of Generation Resources and may qualify as Capacity Resources if they meet the same qualification requirements in Section 4.2.1.1 Qualification Requirements.

- MISO may qualify a resource classified as a Diversity Contract as a Use Limited Resource seasonally provided the resource meets all of the requirements of both an External and Use Limited Resource.
- Use Limited Resources must demonstrate GVTC on an annual basis as described in Section 4.2.1.1 Qualification Requirements. See Appendix J – GVTC Testing Requirements for additional details.
- Use Limited Resources with any new or untested additional capacity are eligible for the ICAP Deferral Process as described in Section 4.5 ICAP Deferral.

4.2.2.2 *Use Limited Resources – SAC Determination*

The SAC values for a Use Limited Resource are based on an evaluation of the resource type and volume of Interconnection Service, GVTC value, and XEFORd value of such Use Limited Resource as described in Appendix H – Non-Schedule 53 Seasonal Accredited Capacity (SAC) Calculations for Planning Resources.

In addition, a Use Limited Resource with contract provisions that prevent the resource from meeting its Must Offer requirement will have a decrease in the SAC calculation to the extent that the contract provisions are less than the required Must Offer requirement of 4 hours across the forecasted peak for each day during the registered Season. Use Limited Resources unable to meet the Must Offer requirements will have their SAC prorated relative to the percentage of hours meeting the Must Offer requirement and to the must offer hours for the Season.

4.2.3 External Resources

MPs may register an External Resource by providing the information listed below to MISO Resource Adequacy to qualify such resources as Capacity Resources. External Resources are registered through the MECT tool for each Planning Resource Auction and reviewed and approved by MISO Resource Adequacy staff. An MP that owns an External Resource or contracts for an External Resource through a power purchase agreement (PPA) may register its External Resources. An MP must denote within the registration if the External Resource being registered is a Use Limited Resource. External Resources that are also Use Limited Resources must meet all requirements in Section 4.2.2.1 “Use Limited Resources – Qualification Requirements” and be approved by MISO Resource Adequacy.

An MP must submit the completed registration form for existing External Resources in the MECT by February 1 prior to the upcoming Planning Year. New External Resource registrations

or existing registrations with increased capacity are to be submitted in the MECT by March 1 prior to the upcoming Planning Year. Existing registrations with increased capacity are required to submit the original GVTC by October 31 prior to the upcoming Planning Year. The completed registration form requires the MP to certify that the registration information is accurate and that the qualifying MWs from External Resources are not being registered by another party. MISO will notify the MP within 15 days after a completed registration form is received regarding accreditation of the External Resource. MISO will review the External Resource registration form for completeness and accuracy, and will notify the MP when it has been determined whether or not the External Resource qualifies for the applicable Planning Resource Auction, or whether there are any outstanding deficiencies in the registration.

4.2.3.1 *External Balancing Authority Qualification Options*

MISO has established host/external Balancing Authority qualification criteria that applies to Balancing Authorities that could impact Energy schedules associated with qualifying External Resources. The Balancing Authority qualification criteria ensures that Energy schedules corresponding to the qualifying External Resources will only be interrupted in a manner that provides consistency, transparency, and reliability.

An executed PPA or External Resource owned prior to April 3, 2014 will continue to qualify as a Planning Resource for the initial full term of the PPA or ownership of the resource, if it is only interruptible as a last resort under Requirement 2 of NERC Standard EOP-011. A Diversity Contract executed prior to April 3, 2014 will continue to qualify as a Planning Resource, if it is only interruptible as a last resort under Requirement 2 of the NERC Standard EOP-011 between June 1 and September 30.

Resources or PPAs that are submitted to MISO for qualification as External Resources must have their corresponding Energy schedules flow through host/external Balancing Authorities that comply with one of the three options outlined below to qualify.

A. Scheduled Interruption Linked to Performance of a Specific Generator in the External Balancing Authority

In the case of unit specific sales, if the MISO Balancing Authority Area is experiencing an Energy Emergency, the external Balancing Authority will not interrupt the schedule from the External Resource unless the generator being used to serve a unit-specific sale has a forced or planned outage.

This type of External Resource would be treated similarly to internal generation because those internal resources constitute Capacity Resources, even when they can be interrupted for forced or planned outages. This provision ensures that the generator delivering the Energy in support of the PPA can be specifically identified.

B. Slice-of-System Curtailed Pro-Rata with Load in the Source Balancing Authority when Source Balancing Authority is in Emergency Procedures

PPA or External Resource fleets in this category will qualify as Planning Resources, so long as the associated capacity schedule only will be curtailed pro-rata, along with load in the source Balancing Authority, and only when the source Balancing Authority is operating under Emergency Procedures.

Under this situation and as an example, a PPA with a 1,000 MW export schedule from an external Balancing Authority with a 3,000 MW load will be curtailed pro-rata along with the load when the external Balancing Authority is operating under Emergency Procedures. That is, curtailment would take place three-quarters to firm load and one quarter to the firm schedule. This pro-rata treatment is triggered when MISO experiences emergency conditions at the same time as the external Balancing Authority.

C. Slice-of-System in a Balancing Authority that Coordinates Planning Reserve Qualifications and Shares Emergency Responsibilities with MISO's Balancing Authority

In addition to the slice-of-system treatment noted in category B above, a slice-of-system PPA or External Resource fleet can qualify as External Resources under this category, and MISO and the external Balancing Authority will share Load Shedding on a pro-rata basis in proportion to the load in the area under the Capacity Emergency, so long as the requirements of this category are met. This qualification category has several requirements for the host Balancing Authority:

1. It must be in MISO's Reliability Coordination Area.
2. It must share Operating Reserves with the MISO Balancing Authority.
3. It must have a Seams Operating Agreement with MISO containing several features. The Seams Operating Agreement must:
    a. Ensure that the host Balancing Authority has established planning reserve processes and criteria similar to MISO.
    b. Specify the actions that will be taken by both entities, MISO and the host Balancing Authority, during Emergency Procedures prior to implementing Load Shedding.

c. Specify that the host Balancing Authority will submit load estimates to MISO in a similar manner as submitted by other Load Serving Entities under Module E-1, provide generator testing data for all resources used to serve firm requirements of the host Balancing Authority, and provide transparency to such resource plans in the form of a FRAP or RBDC Opt Out, pursuant to Module E-1.

With these requirements in place, when both Balancing Authorities have exhausted other emergency operating actions and are in a firm load shedding event, load shedding is shared on a pro-rata basis in proportion to the load in the area under the capacity emergency.

For example, if the load of an external Balancing Authority in capacity emergency is 3,000 MW, and the load of the area in MISO in capacity emergency is 17,000 MW, then pro-rata load shed is 3/20 of the total for the external Balancing Authority and 17/20 for the area in MISO in the capacity emergency.

4.2.3.2 *External Resources - Qualification Requirements*

The following information will be required to register an External Resource:

- Demonstration of firm Transmission Service from the External Resource to the MISO border, and that;
- Firm Transmission Service has been obtained within MISO to deliver the Capacity Resource MWs seeking to be qualified from the External Resource(s) to the Load Zone CPNode within MISO. The Load Zone CPNode will be interpreted as the Local Balancing Authority (LBA) that MISO's OASIS reservation sinks in for Network Customers, or either;
    - The External Resource has Network Resource Interconnection Service under Attachment X.
    - The External Resource was accepted by the Transmission Provider and confirmed by a Network Customer as a designated Network Resource under the OASIS reservation process in place prior to either the initial effective date of the Energy Market in 2005 or that Transmission Owner's integration date.
- External Resources may procure firm Transmission Service (or utilize a Grandfathered Agreement) to meet the deliverability requirements.
    - Firm Transmission Service must either be in the form of a firm Point-to-Point (PTP) Transmission Service Request (TSR) or firm Network Integration Transmission Service (NITS) Scheduling Rights (SR).

        - NITS Scheduling Rights should reference the OASIS NITS Application Reference number or Assignment Reference number, and Resource Name of the Scheduling Right.
    - Firm Transmission Service (PTP TSR or NITS SR) must cover the entire applicable Season within the Planning Year in aggregate and be submitted in the MECT once approved. The resource is only deliverable to the LBA identified in the firm transmission study that grants the NITS SR or PTP TSR.
- Demonstrates that any External Resources or portions of External Resources being registered as Capacity Resources to serve the Load of the LSE are not otherwise being used as capacity resources in any other RTO/ISO or in another state resource adequacy program, is available in the event of an Emergency, and performs an annual GVTC test and reports the data via MISO's PowerGADS (or alternatively, submits a populated Non-GADS Performance Template to the MECT) by October 31 for returning resources and March 1st for new resources.
- External Resources that have been retired prior to the applicable Planning Year will not qualify as a Planning Resource.
- If External Resources used to meet Resource Adequacy Requirements retire or suspend during the Planning Year, they must be replaced effective with their change of status date.
- External Resources greater than or equal to 10 MW based on their GVTC must submit generator availability data to PowerGADS through the MISO Market Portal. This 10 MW threshold applies to individual generator sizes and not to contracted capacity values in PPAs and does not apply to Intermittent Resources or Intermittent Generation. Quarterly GADS Event and Performance Data must be submitted by the end of the month following the quarter (April for Q1, July for Q2, October for Q3, and January for Q4). The submitted data must pass Level 2 Validation without any errors. Units that fail to submit Level 2 Validated quarterly GADS data will be disqualified for participation in the PRA.
- External Resources less than 10 MW based upon GVTC that begin reporting GADS data must continue to report such information.
- Border External Resources and Coordinating Owner External Resources will be modeled, for LOLE and PRA purposes, in the LRZ where their firm Transmission Service crosses the MISO border. All remaining External Resources will be modeled in an External Resource Zone based on their associated External Balancing Authority.

- A PPA may qualify as a Planning Resource if it is valid for the entire Season or is unavailable for no greater than thirty-one (31) days in total for each Season it is being used. If an amended PPA or interim operating plan exists for the Season in which the MP seeks capacity credit, this will be used in calculating the capacity value provided the PPA or interim operating plan contains a capacity amount.
- For a PPA to qualify as a Capacity Resource, it must demonstrate that it complies with the requirements found in Section 69A.3.1.c of the Tariff.
- External Resources that are in service and registering as a Planning Resource for the first time must submit GVTC, and if greater than or equal to 10 MW based on GVTC must submit GADS data (if applicable) prior to being approved as a Capacity Resource.
- An External Resource registration needs to point to a Load Zone CPNode. Along with firm Transmission Service, this acts as verification of deliverability to the load being served by the External Resource.
- All External Resources being used as a Planning Resource are required to perform a real power test according to MISO's Generator Test Requirements and submit the GVTC data to MISO's PowerGADS no later than October 31 to qualify as a Planning Resource. The test shall be performed between September 1 and August 31 of the prior Planning Year and be corrected to the average temperature of the date and times of MISO's coincident seasonal peaks, measured at or near the generator's location, for the last 5 years, or provide past operational data that meets these requirements to determine its GVTC and submit its GVTC data to MISO's PowerGADS.
    - Resources that do not submit real power tests through GADS must submit a populated Non-GADS Performance Template via MECT as substitute. Existing resources must do this by October 31, while new resources should submit this template by March 1.
- External Resources undergoing gas conversion are not required to submit GVTC prior to returning.
- MPs who register a slice-of-system External Resource are responsible for ensuring proper outage and GVTC data is submitted to MISO through PowerGADS, unless a populated Non-GADS Performance Template is submitted via MECT for the External Resource. This information is due no later than October 31 of the prior Planning Year to qualify as a Planning Resource.

When to Perform and Submit a Generation Verification Test Capacity (GVTC)

- External Resources that qualified as Planning Resources for the current Planning Year shall submit their GVTC data no later than October 31 in order to qualify as a Planning Resource for the upcoming Planning Year. GVTC can be met by a real power test or past operational data must be provided during the test period between September 1 and August 31 prior to the upcoming Planning Year.
- A real power test is required to demonstrate a modification that increases the rated capacity of a unit, and then submit the revised GVTC to MISO by March 1. The initial GVTC should be submitted by October 31 prior to the Planning Year.
- A real power test is required when returning from a suspended state and the results of the GVTC should be submitted to MISO via the PowerGADS system.
- A real power test is required when any unit returns to MISO after an absence (including but not limited to, catastrophic events, or not qualified as a Planning Resource under Module E-1) or being qualified as a Planning Resource for the first time and must be submitted to MISO no later than March 1 prior to the Planning Year.
- The GVTC for a new External Resource is due before a Market Participant registers the new External Resource in the MECT and must be submitted by March 1 prior to the upcoming Planning Year.
- See Appendix J – GVTC Testing Requirements.
- External Resources with any new or untested additional capacity are eligible for the ICAP Deferral process as described in Section 4.5 ICAP Deferral.
- Reporting is accomplished through MISO's PowerGADS reporting system as described in MISO's Capacity Verification Manual, which is located on MISO's PowerGADS > Tools > Guide.

4.2.3.3 *Submission of new External Resource Registrations*

A Market Participant must register their new External Resource via the Registrations screen in the MECT by March 1 prior to the Planning Year. To guarantee new resources can be used in an LSE's FRAP or RBDC Opt Out, registrations must be submitted no later than February 15 prior to the Planning Year. The registering entity must be a Market Participant prior to registering an External Resource. Any entity that is not a Market Participant, but desires to register an External Resource, must contact the Client Services and Readiness team at MISO Help Center (https://help.misoenergy.org/) to become a Market Participant. The resource information submitted through the Registrations screen will require the Market Participant to

certify that the registration information is accurate, complete, and that the qualified MWs from the External Resource are not being registered by another party or used in another Balancing Area for capacity purposes. Appendix F, External Resources, contains the information that must be submitted by an MP through the MECT on the Registrations screen.

4.2.3.4 *Amendments to Accredited External Resource Registration Data*

The Market Participant can amend the registration for an External Resource for an upcoming Planning Year by providing MISO notification no later than March 1 if the original registration was submitted by the deadline.

4.2.3.5 *Renewal of External Resource for Subsequent Planning Years*

Renewed External Resource registrations must be submitted by February 1 prior to the upcoming Planning Year. MISO will review the renewed External Resource registration information for completeness and accuracy and ensure it complies with the qualification requirements for an External Resource. MISO will notify the Market Participant within 15 days after the renewed registration form has been submitted as to whether or not the External Resource has been accredited as an External Resource, or whether there are any deficiencies within the registration that must be corrected. If the External Resource is accredited as an External Resource, it will be given a unique name for tracking purposes and made available in the MECT for use by the MP during the applicable Planning Year.

4.2.3.6 *Review of Power Purchase Agreements*

Market Participants that have entered into power purchase agreement(s) for future Planning Years must provide to MISO the documentation that demonstrates the active power purchase agreement and MISO will make a preliminary determination of whether the agreement(s) would qualify as External Resources from power purchase agreement(s) as set forth in sections 69A.3.1.c.(i) through 69A.3.1.c.(v) of the Tariff. PPAs meeting these requirements are considered conforming. Market Participants must submit this documentation as part of the External Resource registration process and will be reviewed by MISO Resource Adequacy staff.

MISO Resource Adequacy and Legal staff will review the submitted agreement(s) and respond within 60 days of receipt of the request. MISO will provide written confirmation as to whether the contract meets the current Tariff requirements. Any such determination is based upon the existing version of the Tariff, which may be modified from time to time subject to the acceptance of such modifications by the Federal Energy Regulatory Commission. The Market Participant requesting an advanced review of their agreements will need to follow the procedures

applicable to the planning period for which such External Resource is intended to be relied upon to meet capacity requirements. This includes the provision of the appropriate GVTC and GADS data and other requirements then in effect for registering an External Resource as set forth in the Tariff and in Section 4.2.3 External Resources, to have the External Resource modeled in the MECT and qualified as a Capacity Resource. Any subsequent modifications to the PPA will be subject to a new confirmation determined by MISO regarding the portion of the term.

PPAs that do not meet the requirements of Section 69A.3.1.c (i) through (v) of the Tariff are considered non-conforming and must provide MISO with all the following information in order to qualify as a Capacity Resource:

a) The PPA was executed prior to October 20, 2008;
b) NERC regional entity has accredited the PPA to satisfy resource adequacy requirement provisions;
c) The PPA has provided reliable capacity to the Transmission Provider Region;
d) The supplier(s) of capacity in the PPA commit(s) to provide the capacity to an LSE in the Transmission Provider Region in a defined amount at a defined location based upon the supplier(s)' portfolio of generation assets;
e) Energy from the PPA cannot be interrupted for economic reasons and will only be interrupted for force majeure type conditions as a last resort during Emergency conditions;
f) Either the purchaser(s) or the supplier(s) of capacity in the PPA has committed to offer energy into the Day-Ahead Energy and Operating Reserves Market and all pre-Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment processes for all periods for which Energy is available under the PPA, consistent with the must offer provisions in Section 69A.5;
g) The physical resource(s) backing the PPA are identified by the supplier of the PPA;
h) The portion of the physical resources backing the PPA has not otherwise been registered by any other entity as Capacity Resources in the MISO Region or as capacity resources in any other region; and
i) If the PPA is renewed, the PPA will be modified to comply with the terms of Section 69A.3.1.c (i) through (v) and (vii).

4.2.3.7 *External Resources – SAC Determination*

The Seasonal Accredited Capacity (SAC) for External Resources will be accredited based on seasonal GVTC values and seasonal Transmission Service, and seasonal $XEFORd_d$ (where applicable) values of such External Resources, are based on the methodology documented in

Appendix H – Non-Schedule 53 Seasonal Accredited Capacity (SAC) Calculations for Planning Resources. MISO will determine SAC values for External Resources that are Intermittent Generation as described in Section 4.2.1.4 – Dispatchable Intermittent Resources and Intermittent Generation Resource – SAC Determination. External Resources, from PPAs, with varying monthly capacity values will be credited with the monthly capacity value of the contract that corresponds with the seasonal peak Demand month, unless the resource(s) supporting the PPA are considered Intermittent Generation.

4.2.3.8 *Dually Connected Border External Resources*

Border External Resources can have interconnection facilities which connect to multiple LRZs. In those instances, these resources would be modeled in a single Local Resource Zone with which the resource has the greatest connectivity. Connectivity is measured using shift factor analysis that evaluates the generator's impact on flows on the Transmission System. The analysis is performed based on the latest models and input files used in support for the upcoming PRA. The study model is created by ramping the resource up and sinking the output to the MISO footprint. Line loadings in the connected LRZs are compared with those of the base model to determine the impact of the unit. The study will include consideration of tie line flow, impact on historical constraints, and impacts on the connected LRZs as a whole. Results of the analysis will be posted on MISO's website prior to the Planning Resource Auction. Details regarding the resource's impact on individual transmission lines will not be published.

4.2.3.9 *SAC Determination – Fixed Capacity PPA*

Market Participants may register External Resources where the supplier has guaranteed delivery of a fixed MW value of capacity. Market Participants must contact MISO Resource Adequacy for a review of this type of PPA. Subsequent approval of such contracts by MISO results in an accreditation of XEFORd and the SAC will be set equal to the ICAP of the External Resource registered. PPAs backed by an Intermittent Resource do not qualify as this type of PPA.

4.2.3.10 *SAC Determination – Full Requirements PPA*

Market Participants may register External Resources to model a full requirements power purchase agreement with a counterparty. This results in the ICAP of the External Resource being increased for the Planning Reserve Margin, applicable Transmission Losses, and the Forced Outage rating. This adjusted ICAP will be used in the External Resource's SAC and Must Offer calculations. Market Participants must contact MISO Resource Adequacy for a review of these types of contracts.

$$ICAP_{Adjusted} = \sum_{GADS\ Resources} \left(\frac{ICAP_i\ x\ (1 + PRM_{LRZ})\ x\ (1 + TL_{LBA})}{(1 - XEFORd_i)} \right)$$

Where:
$ICAP_{adjusted}$: PPA Percent x Resource ICAP or amount owned by MP
$XEFORd_i$: XEFORd of selected GADS resource
PRM_{LRZ}: Planning Reserve Margin Requirement for the Local Resource Zone that the External Resource will be serving Load in
TL_{LBA}: Transmission Losses for the LBA that the External Resource will be serving load in

4.2.4 DRR Type I and Type II – Qualification Requirements

Demand Response Resources (DRR) Type I and Type II may qualify as Capacity Resources provided that the following criteria are met. (All references to generation availability and testing in this section pertain to DRRs backed by generation.):

- DRR Type I and Type II backed by behind the meter generation (that are not Intermittent Generation and Dispatchable Intermittent Resources) must submit generator availability data (including, but not limited to, NERC GADS) into the PowerGADS tool through the Market Portal.
- DRR Type I and Type II must demonstrate seasonal capability on an annual basis. Verification of DRR Type I and Type II capability will be in accordance with the guidelines established by the applicable Regional Entity, unless superseded by specific verification guidelines set by the applicable state authorities.
- DRRs may qualify as Capacity Resources if they meet the same qualification requirements in Section 4.2.1.1 Qualification Requirements.
- DRRs must demonstrate seasonal corrected GVTC on an annual basis as described in Section 4.2.1.1 Qualification Requirements. See Appendix J – GVTC Testing Requirements for additional details.
- DRRs with any new or untested additional capacity are eligible for the ICAP Deferral Process as described in Section 4.5 ICAP Deferral.

4.2.4.1 *DRR Type I and Type II – SAC Determination*

MISO will determine the SAC value for each Demand Response Resources backed by behind the meter generation based on an evaluation of GVTC value and XEFORd values of such generator. If such behind the meter generation facility is interconnected to the Transmission

System, MISO will consider the type and volume of the interconnection service when determining the Unforced Capacity. If GADS data is not required to be submitted by the MP, then a class average EFORd of the resource type will be used to calculate the forced outage rate (XEFORd) for the resource.

A XEFORd value of zero will be applied to all DRR that interrupts or controls load but is not backed by behind the meter generation.

SAC MW options for units with derates prior to the GVTC test date is further explained in Appendix J.4 – Generation Verification Test Capacity During a Derate.

4.2.5 Load Modifying Resource Obligations and Penalties

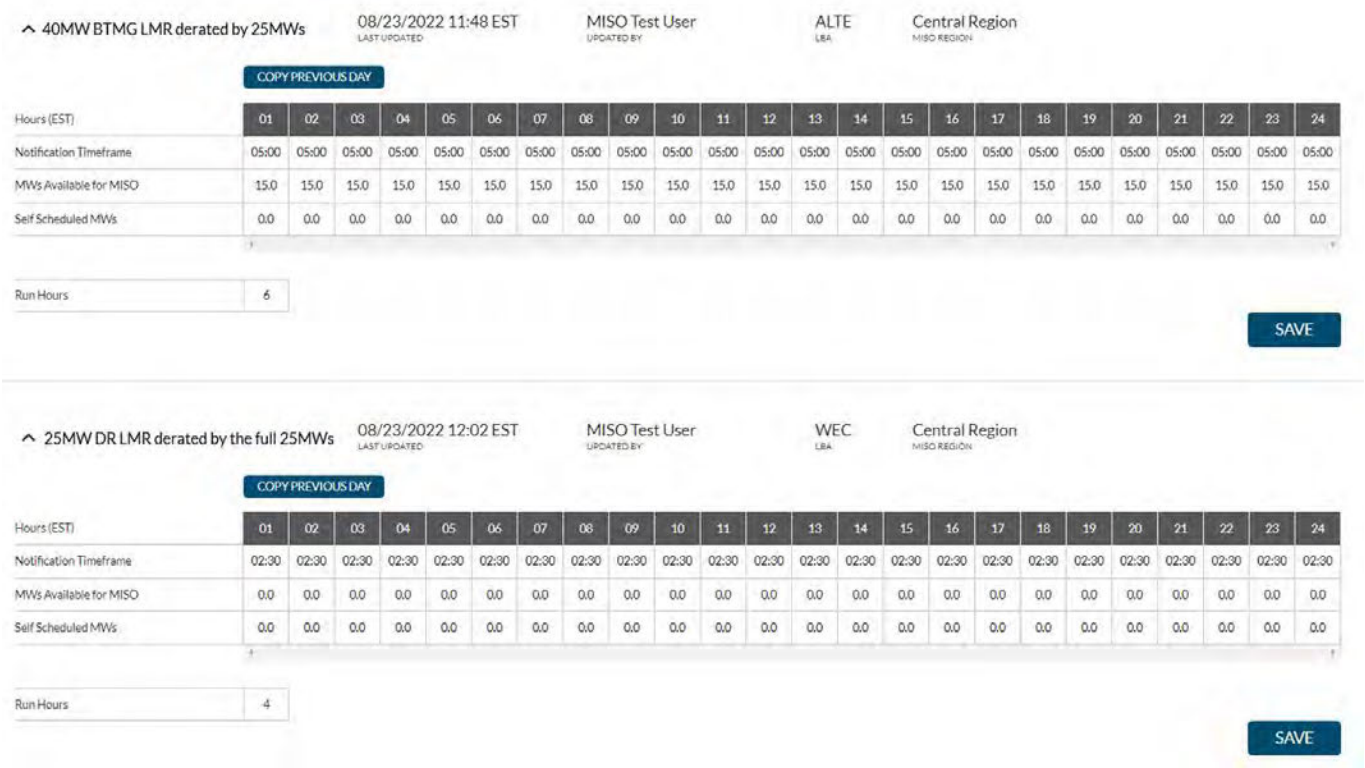
Load Modifying Resources (LMRs) consist of Demand Resources (DR) and Behind the Meter Generation (BTMG). A Demand Resource shall mean a resource registered with MISO defined as Interruptible Load or Direct Load Control Management and other resources that result in additional and verifiable reductions in end-use customer Demand during an Emergency.

Behind the Meter Generation is defined as a generation resource used to serve wholesale or retail load that is located behind a Load Zone CPNode. BTMG is not included in MISO's Setpoint Instructions. An LMR that exclusively relies only on a generator to accomplish the load reduction and remains synchronously connected to the grid, or injects onto the grid, must register as a BTMG. In scenarios where LMRs represent an interruptible program that disconnects the load from the grid and activates a local backup generator to provide power on an asynchronous island, independent from the grid, a DR registration may be used.

BTMG and DR requirements to qualify as an LMR are covered in Sections 4.2.6 - BTMG Qualification Requirements and 4.2.7 - Demand Resource (DR) Qualification Requirements of this BPM.

LMRs differ from Capacity Resources in that they do not have a must offer requirement, however, they must be available for use within MISO as defined in this BPM during Emergency events (including capacity and transmission events) declared by MISO unless unavailable because of maintenance, Force Majeure or other reasons outlined in this BPM. LMRs communicate to MISO their availability through the Demand Side Resource Interface (DSRI). MPs with LMR assets must provide updates to availability specific to each LMR that is listed in

the DSRI. The DSRI is populated with the monthly Demand Reduction Capability Forecast values provided at the time of the LMR registration. If the LMR partially clears, the value in the DSRI will be adjusted by the % of the total seasonal ZRCs a resource clears in a Planning Resource Auction (PRA) or used in a Fixed Resource Adequacy Plan (FRAP) or RBDC Opt Out times the Demand Reduction Capability Forecast. If the LMR only partially clears the PRA, MISO will grant an opportunity to adjust the monthly MW values to account for the cleared LMR ZRCs. It is critical that LMR availability always be current as the Scheduling Instructions (dispatch directives) and ultimately performance and availability review will utilize the information in the DSRI at the time the Scheduling Instruction is issued and how the Market Participant responds to the Scheduling Instruction. If the LMR is on any type of derate, outage or otherwise not available, the LMR availability should be adjusted by decrementing the availability in the DSRI by reducing the “MWs available for MISO” for the affected LMR. The following are two examples of a 40 MW BTMG LMR derated by 25 MWs, and a 25 MW DR LMR derated by the full 25 MWs and is completely in outage:



40MW BTMG LMR derated by 25MWs — 08/23/2022 11:48 EST (LAST UPDATED) — MISO Test User (UPDATED BY) — ALTE (LBA) — Central Region (MISO REGION)

COPY PREVIOUS DAY

Hours (EST)	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Notification Timeframe	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00
MWs Available for MISO	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Self Scheduled MWs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Run Hours: 6

SAVE

25MW DR LMR derated by the full 25MWs — 08/23/2022 12:02 EST (LAST UPDATED) — MISO Test User (UPDATED BY) — WEC (LBA) — Central Region (MISO REGION)

COPY PREVIOUS DAY

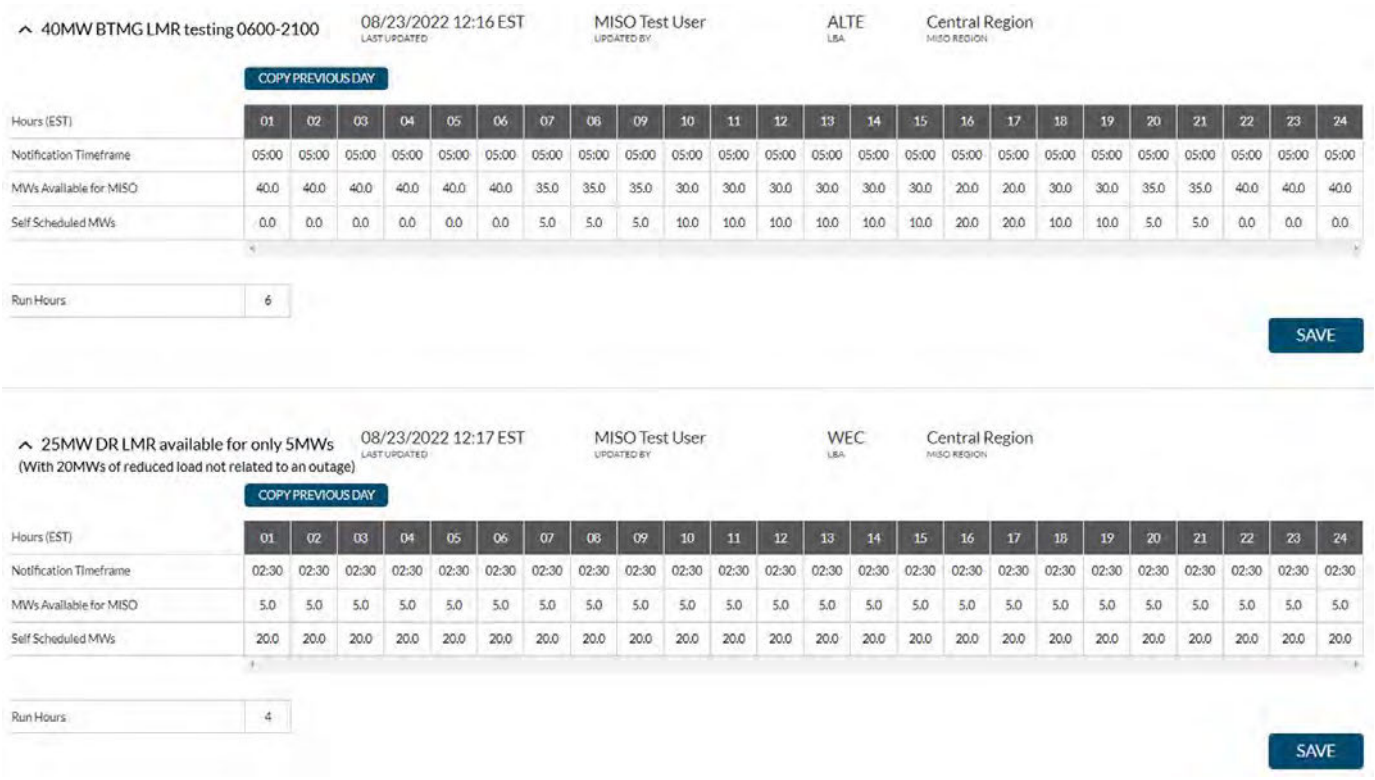
Hours (EST)	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Notification Timeframe	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30
MWs Available for MISO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Self Scheduled MWs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Run Hours: 4

SAVE

If a BTMG is scheduled to be deployed by the MP, the “Self Scheduled MWs” section in the DSRI should be increased for LMR MWs that are scheduled to be deployed and the “MWs available for MISO” amount should be reduced to reflect the remaining MWs available for additional MISO deployment. If a DR is scheduled to be deployed by the MP, or it simply has

reduced load for the end-use at the facility then the “Self Scheduled MWs” section in the DSRI should be increased for LMR MWs that are scheduled to be deployed or has been already reduced, and the “MWs available for MISO” amount should be reduced to reflect the remaining MWs available for additional MISO deployment. Derates and outages that occur where load is not reduced should not be entered as “MWs available for MISO” or “Self Scheduled MWs”. The following are two examples of a 40 MW BTMG LMR coming online for a test between 0600 – 2100, and a 25 MW DR LMR available for only 5 MWs for MISO because there is reduced load at the facility:



40MW BTMG LMR testing 0600-2100 — LAST UPDATED 08/23/2022 12:16 EST — UPDATED BY MISO Test User — LBA ALTE — MISO REGION Central Region

COPY PREVIOUS DAY

Hours (EST)	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Notification Timeframe	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00	05:00
MWs Available for MISO	40.0	40.0	40.0	40.0	40.0	40.0	35.0	35.0	35.0	30.0	30.0	30.0	30.0	30.0	30.0	20.0	20.0	30.0	30.0	35.0	35.0	40.0	40.0	40.0
Self Scheduled MWs	0.0	0.0	0.0	0.0	0.0	0.0	5.0	5.0	5.0	10.0	10.0	10.0	10.0	10.0	10.0	20.0	20.0	10.0	10.0	5.0	5.0	0.0	0.0	0.0

Run Hours: 6

SAVE

25MW DR LMR available for only 5MWs
(With 20MWs of reduced load not related to an outage) — LAST UPDATED 08/23/2022 12:17 EST — UPDATED BY MISO Test User — LBA WEC — MISO REGION Central Region

COPY PREVIOUS DAY

Hours (EST)	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Notification Timeframe	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30	02:30
MWs Available for MISO	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Self Scheduled MWs	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0

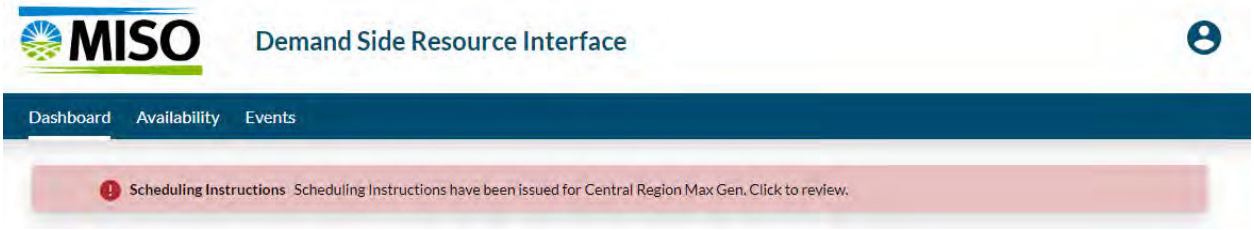
Run Hours: 4

SAVE

For specifics on DSRI functionality, please see the MP LMR Users Guide located in the Learning Center.

If an Emergency is declared by MISO that requires LMR deployment, MISO will issue Scheduling Instructions in the DSRI using the LMR availability information (“MWs available for MISO” and “Self Scheduled MWs”) provided by MPs. Self Scheduled MWs are included in a Scheduling Instruction to ensure that the MW deployed voluntarily by an MP continue to be deployed if required during an Emergency. Self Scheduled MWs are not subject to notification

times because they are already planned to be performing at those levels, as decided by the MP; however, MWs available for MISO are subject to notification times whenever Scheduling Instructions are created. The LBA and the MP will receive a notification of the Scheduling Instructions via a MISO Communications System (MCS) message (LMR Implementation MCS message type). MPs will also receive a Scheduling Instructions event banner within the DSRI application as shown below (with audible alerts until acknowledged).



Market Participants with LMRs must have personnel operating on a 24x7 basis that can receive and respond to MCS messages, Operator Interface Declarations and Messages, and LMR Scheduling Instructions events in the DSRI. The MP will need to acknowledge receipt of the Scheduling Instruction and update the remaining availability, if any, of the LMR(s) being used to meet the Scheduling Instruction in DSRI to reflect the MW amount available in the specified time(s). This update and acknowledgement should be done within one (1) hour of receiving the Scheduling Instruction from MISO. Also, before the Emergency deployment, the MP that registered the LMR(s) should submit the specific designation of LMRs and associated MWs used to meet the total MWs contained in the Scheduling Instruction via the Resource Deployment tab of the LMR Scheduling Instruction Event in the DSRI.

MPs that report LMR availability (including self-scheduled MWs) in the DSRI that is less than the performance obligation based on the MW value that is being used to meet RAR, may be requested to provide documentation and/or metering data to MISO for the dates and hours that MISO declared an Emergency. Meter data for the LMRs used to meet the MWs requested in the Scheduling Instruction mustbe uploaded in the Demand Response Tool within 103 days of the Emergency event or as requested by MISO.

MISO will not violate registration parameters (e.g., notification time) and real time availability updates provided by MPs when issuing a Scheduling Instruction. MISO does, however, rely on real time availability updates provided by MPs when issuing a Scheduling Instruction.

4.2.5.1 *LMRs with Dual Registration*

Market Participants that register LMRs are eligible to also register in the Energy market as Emergency Demand Resources and/or Demand Response Resources.

LMRs that have some capability registered as Emergency Demand Response (EDR) or Demand Response Resource (DRR) should adjust their availability in DSRI to reflect net LMR MWs available to MISO (e.g. decrement total LMR capability by EDR offer amount and DRR cleared Day-Ahead or pending Real Time offer). It is the responsibility of the Market Participant to ensure no double counting of MWs offered across the dual registration types. Double counted MWs may be subject to underperformance penalties.

1.1.1.1.3 4.2.5.1.1 LMRs Also Registered as Demand Response Resource (DRR)

DRR Type I and Type II that have converted SAC to ZRCs which were used to meet seasonal Resource Adequacy Requirements (RAR) are categorized as Capacity Resources under Module E-1 (Section 69A.3.1.b) and therefore are not LMRs. However, a DRR that does not convert all its associated SAC may also register the remaining SAC of the resource as an LMR. In this case, the SAC converted and used to meet RAR under the LMR designation would follow the respective LMR requirements and likewise the DRR SAC if converted and used to meet RAR would carry the must offer requirement. The combined SAC converted to ZRCs between the DRR designation and the LMR designation cannot exceed the assigned SAC value of the singular resource.

1.1.1.1.4 4.2.5.1.2 LMRs Also Registered as an Emergency Demand Resource (EDR)

A resource may qualify as an Emergency Demand Response (EDR) under Schedule 30 to participate in the Energy market regardless of whether it qualifies as an LMR under Module E-1. An LMR may also dually register and qualify as an EDR. In the case of a dual LMR / EDR registration, the resource may be dispatched as an EDR when there is a pending EDR offer (EDR offers are made daily). If the resource is not dispatched as an EDR, it maintains its LMR obligations, and its performance will be evaluated as such. Being dual registered requires the resource to meet the most stringent of the two designations' requirements. Also, the tolerance band allowed for an EDR does not apply when dual registered. MISO will not assign LMR penalties to Emergency Demand Response (EDR) resources that have already been assessed penalties under Schedule 30 of the Tariff.

For more information regarding the dual registration of LMRs as EDRs, please see Section 6.4 of BPM-026 Demand Response.

1.1.1.2 4.2.5.2 LMR Performance Obligations

The registered capacity of accredited LMRs that has been converted to ZRCs and has cleared in the PRA must be available as outlined above for use in the event of an Emergency declared by MISO. MISO will populate the DSRI with the monthly Demand Reduction Capability Forecast values provided at the time of the LMR registration. If the LMR partially clears, the value in the DSRI will be adjusted by the % of the total seasonal ZRCs a resource clears times the Demand Reduction Capability Forecast. MPs should keep these values up to date to ensure the availability is accurate as Scheduling Instructions will be based on the LMR Availability in the DSRI. The Available MWs for MISO should be consistent with the availability indicated in the LMR's registration. A Market Participant utilizing LMRs to meet Resource Adequacy Requirements will be subject to the penalties described in Section 69A.3.9 of the Tariff if the LMR is included in the Market Participant's response to Scheduling Instructions and the LMR fails to respond.

A Demand Resource (DR) must respond with an amount greater than or equal to the target level of load reduction or reduce Demand at or below the registered firm service level. DRs that registered with a Firm Service Level Measurement & Verification methodology that partially clear, will have the uncleared portion of the resource added to their registered firm service level (FSL) when evaluating performance. A BTMG must provide the target level of generation increase as indicated on the Market Participant's Resource Deployment tab of the LMR Scheduling Instruction Event in the DSRI when responding to Scheduling Instructions Combined, the Market Participant's DR and BTMG responses must meet the total MWs contained in their Scheduling Instruction.

This "target" level MW is indicated by the MP via the DSRI's Resource Deployment tab of the LMR Scheduling Instruction Event which outlines which LMRs were utilized and the associated MW levels to meet the total MWs contained in the Market Participant's Scheduling Instruction. An LSE shall be assessed the costs that were otherwise incurred to replace the Energy deficiency at the time the LMR was dispatched.

MISO will not assign LMR penalties to Emergency Demand Response (EDR) resources that have already been assessed penalties under Schedule 30 of the Tariff. LMR values entered in the DSRI availability will also be considered when evaluating whether target levels of generation

increase, or Load reduction have been met. For more information regarding the performance assessment of an LMR, please see BPM-026 Section 6.2.

The operators of LMRs that improperly report to MISO that an LMR is unavailable in the DSRI prior to receiving a Scheduling Instruction or the LMR does not respond when included in a Market Participant's response to Scheduling Instructions will have an opportunity to provide documentation of the specific circumstances that would justify exemption from such penalties. A penalty will not be assessed for any portion of the target level of Load reduction for a DR, or target level of generation increase for a BTMG, which had already been accomplished for other reasons (*i.e.*, for economic considerations, self-scheduling at or above the amount of BTMG committed in a Planning Resource Auction, or local reliability concerns) and properly reflected in the hourly availability in the DSRI for each resource. Likewise, for certain LMRs that are temperature dependent (*e.g.*, a Demand Resource program involving air conditioning load), the target level of Load reduction or target level of generation increase may be adjusted and the hourly availability in the DSRI should be updated to properly reflect the anticipated capability of the resource.

4.2.6 BTMG Qualification Requirements

MPs with BTMGs can qualify as LMRs by:

- Submitting monthly availability (in megawatts) and notification time (in hours) for the upcoming Planning Year.
- Intermittent BTMG (e.g., solar, wind, run-of-river hydro, etc.) are exempt from submitting the additional documentation for monthly availability and notification time as they are not dispatched via the DSRI.
- Confirming through the registration process such BTMG can be available to provide Energy with no more than 6 Hours advance notice from MISO or the LBA and sustain Energy production for a minimum of four (4) consecutive Hours.
- Confirming through the registration process that the BTMG is capable of being interrupted and available at least the first (5) times as needed during the Summer and Winter and at least the first (3) times as needed during the Spring and Fall by MISO or the LBA for emergency event purposes, consistent with the registration information of the physical capability of the BTMG.
- Confirming that the BTMG is equal to or greater than 100 kW (an aggregation of smaller resources that can produce Energy may qualify in meeting this requirement if located in the same LRZ).

- Behind the Meter Generation must demonstrate GVTC on an annual basis as described in Sec. 4.2.1.1 Qualification Requirements. See Appendix J – GVTC Testing Requirements for additional details.
- Behind the Meter Generation with any new or untested additional capacity are eligible for the ICAP Deferral Process as described in Sec. 4.5 ICAP Deferral.
- Submitting generator availability data (including, but not limited to, NERC GADS) into a database through the Market Portal for non-intermittent BTMG greater than or equal to 10 MW based on GVTC. Non-intermittent BTMG less than 10 MW based upon GVTC that begin reporting generator availability data must continue to report such information. Behind the Meter Generation that is an intermittent resource must submit information in accordance with Section 4.2.1.3 Intermittent Generation and Dispatchable Intermittent Resources - Qualification Requirements. Quarterly GADS Event and Performance Data must be submitted by the end of the month following the quarter (April for Q1, July for Q2, October for Q3, and January for Q4). The submitted data must have passed Level 2 Validation without any errors. Units that fail to submit Level 2 Validated quarterly GADS data will be disqualified for participation in the PRA.
- For wind resources being registered as BTMG, the following information is required:
    - Resources with commercial operation history of metered values during at least one Season would submit metered values in MW terms for all Hours in the test period.
    - Resources with no commercial operation history of metered values during the Season would receive class average for each Season within the Initial Planning Year.
- For solar resources being registered as BTMG, the following information is required:
    - Resources with at least 30 consecutive days of metered values for that Season would submit metered values in MW terms for all hours in the test period.
    - Resources with less than 30 consecutive seasonal days of metered values would receive class average for the Seasons within the Initial Planning Year.
- For storage resources that do not report to GADS (including but not limited to, batteries, flywheels, compressed air, and pumped storage) being registered as BTMG, the following information is required:
    - Resources with commercial operation history of metered values during no less than 30 consecutive days in a specific Season would submit historic

availability for the top 8 coincident system peak hours for a minimum of one and a maximum of three of the most recent applicable Planning Years for each Season.

- Resources with less than 30 consecutive days of metered values during a Season would receive class average accreditation for the Initial Planning Year.

- Internal purchase power agreements (PPAs) will not be qualified by MISO.
- BTMGs that have been retired prior to the Season will not qualify as a Planning Resource.
- If BTMGs used to meet Resource Adequacy Requirements retire or suspend during the Planning Year, they must be replaced effective with their change of status date.

4.2.6.1 *Submission of New BTMG Registrations*

An MP must register its new BTMG via the Registration screen in the MECT by March 1 prior to the Planning Year. The registering entity must be an MP prior to registering a BTMG. In order to guarantee new Resources can be used in an LSE's FRAP or RBDC Opt Out, registrations should be submitted no later than February 15 prior to the Planning Year. An entity that is not a MP, but desires to register a BTMG, must contact the Customer Registration team at register@misoenergy.orgMISO Help Center (https://help.misoenergy.org/) to become a MP. During the registration process the MP will be required to certify that the registration information is accurate, complete, and that the qualified MWs from the BTMG are not being registered by another party. Appendix E contains the information that must be submitted by an MP through the MECT registration screens. MISO will review the BTMG registration information for completeness and accuracy and ensure it complies with the qualification requirements for BTMG. MISO will endeavor to notify the MP within 15 days after the registration form was submitted regarding whether the BTMG has been accredited as an LMR, or whether there are any deficiencies that must be corrected. If the BTMG is accredited as an LMR, it will be given a unique name for tracking purposes and made available in the MECT screens for use by the MP.

4.2.6.2 *Termination of BTMG Accredited as LMR*

Because BTMGs need to be accredited seasonally, the "Effective Stop Date" will default to the last day of the applicable Season.

4.2.6.3 *Amendments to Accredited BTMG Registration Data*

The Market Participant can amend the registration for a BTMG for an upcoming Planning Year by providing MISO notification no later than March 1 if the original registration was submitted by February 1.

The Market Participant may modify any of the non-end date information submitted in the registration, which may affect the BTMG's qualification, including, but not limited to, a change in operation, or either an increase or decrease in MW capability. The Market Participant shall submit new or amended registration information in the MECT by March 1 prior to a Planning Year for MISO to determine whether the resource still qualifies as a BTMG. The Market Participant will still need to provide MISO with a GVTC by the original test date as outlined in the BPM. Any modifications in the capability of an existing BTMG must have updated test and registration information submitted to MISO via the MECT by March 1.

Renewal of BTMG for subsequent Planning Years

BTMG must be reviewed for accreditation as an LMR on an annual basis. An MP can request renewal of BTMG accreditation for subsequent Planning Years through the MECT registration screens. Renewal of BTMG must be requested by February 1^{sr} prior to the Planning Year.

NOTE: BTMGs must submit GVTC and/or operational data by the October 31 deadline, per Section 4.3, to have SAC values determined. MISO will review the revised BTMG registration information for completeness and accuracy and ensure it complies with the qualification requirements for BTMG. MISO will endeavor to review the registration for approval within 15 days after the revised registration form was submitted to determine whether the BTMG has been accredited as an LMR, or whether there are any deficiencies that must be corrected. If the BTMG is accredited as an LMR, then it will be given a unique name for tracking purposes and be made available in the MECT screens for use by the MP during the applicable Planning Year.

4.2.6.4 *Behind the Meter Generation (BTMG) – SAC Determination*

The SAC value for a BTMG is based on an evaluation of the applicable type and volume of interconnection service, GVTC (or historical output at peak if intermittent), line losses if not interconnected to MISO, and XEFORd value of such BTMG.

BTMG that are intermittent resources will have their SAC determined consistent with the methodology described for similar resource fuel types as described in Section 4.2.1.3,

Intermittent Generation and Dispatchable Intermittent Resources – Qualification Requirements, through 4.2.1.7, Other Intermittent Generation and Dispatchable Intermittent Resources.

4.2.6.5 *BTMG Deliverability*

Each BTMG resource owner must coordinate with their Distribution Provider (DP) to ensure local distribution service for the BTMG resource to qualify as an LMR type Planning Resource for participation in the PRA. The majority of BTMG is interconnected at distribution-level voltage; however, it is possible for BTMG to be interconnected at transmission-level voltage. Additionally, MPs with BTMG must coordinate with their LSE, DP, and Transmission Owner (TO) to determine eligibility to participate in the PRA. This section will outline the roles and responsibilities of an LSE, DP, TO, and MISO for an individual BTMG to participate in the PRA including specific methodologies available to the BTMG MP to demonstrate deliverability. Responsibilities of an entity may differ depending if the Point of Interconnection is on the distribution system or transmission system and will be noted.

1.1.1.2.1 4.2.6.5.1 Roles and Responsibilities to Determine Eligibility for PRA Participation

Additional descriptions of the role and responsibility of each entity is below. The MP owning a BTMG is responsible for providing an attestation to MISO that proper coordination has occurred with each entity.

Load Serving Entity (LSE): Collaborate with BTMG MP to establish eligibility for a BTMG to participate in the wholesale market (e.g., PRA) in accordance with the relevant state regulatory framework.

Distribution Provider (DP): Ensure reliability of distribution system and assess access to the transmission system. Typically, the DP completes an interconnection study to assess the reliability impacts on the distribution system. The DP is responsible for determining engineering studies, facility upgrades, and/or agreements required to permit access of a BTMG to the transmission system.

Transmission Owner (TO): Determine when the transmission system is utilized by a BTMG to serve load and coordinate with the DP and MISO on engineering and facility studies as appropriate. The TO typically ensures studies are completed, per their direction, to ensure

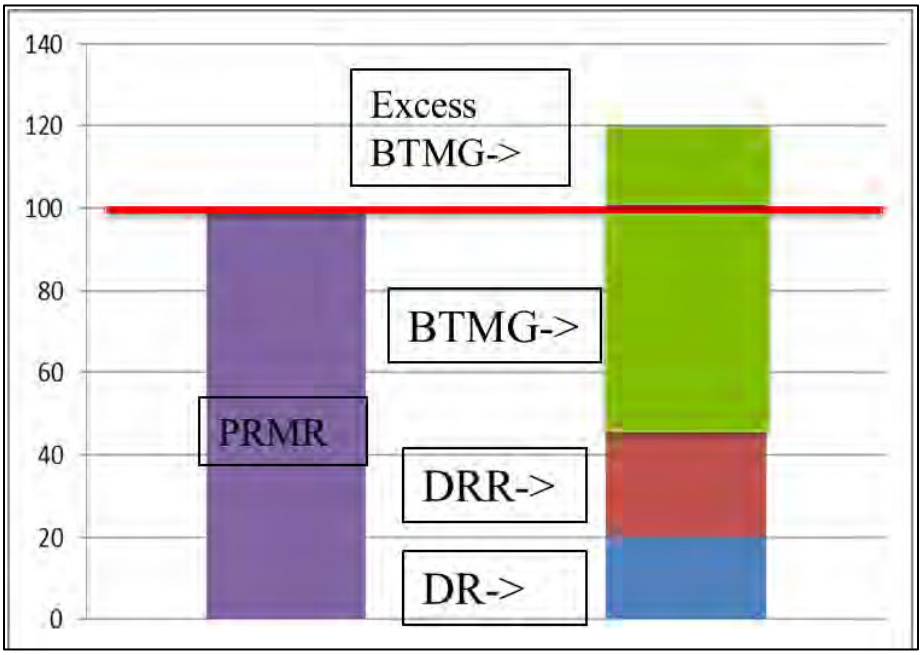
transmission facilities (including other interconnected generators) are not impacted by an additional injection of Energy from a BTMG onto the transmission system. Studies will vary depending on the specific Point of Interconnection.

MISO: Accountable for ensuring BTMG has demonstrated deliverability for use in the PRA (additional details below) and ensuring the BTMG MP has provided attestation of coordination with the LSE, DP, and TO.

1.1.1.2.2 4.2.6.5.2 Definition of "Excess BTMG"

Deliverability of BTMG is established relative to the portfolio of total BTMG assets owned or under contract by an LSE in a singular LBA. A BTMG that utilizes the transmission system or a volume of BTMG exceeding an LSE's "net PRMR" in a singular LBA is considered "Excess BTMG" and will need to demonstrate deliverability utilizing an option described in Sec. 4.2.6.5.3 – Options for BTMG to Demonstrate Deliverability. It is possible for the volume of "Excess BTMG" SAC to be less than the SAC of a singular BTMG. In this instance, the MP is eligible to demonstrate deliverability for a portion of a generator or multiple generators. MISO will collaborate with the BTMG MP to establish the specific Point of Injection onto the Transmission System.

The term "net PRMR" is utilized rather than Initial PRMR because it is possible for an LSE to have a portfolio of ZRCs that include registered Demand Resources (DR) and Demand backed Demand Response Resources (DRR_{demand}) that reduce the expected peak Demand by an LSE and result in a net injection onto the Transmission System. Net injection onto the Transmission System is "Excess BTMG" as represented by the figure below.



1.1.1.2.3 4.2.6.5.3 Options for BTMG to Demonstrate Deliverability

Below are the multiple options for a MP with BTMG to demonstrate deliverability:

Option 1: BTMG utilizing the distribution system to offset Initial PRMR. BTMG used to offset an LSE's load utilizing only the distribution system is considered deliverable up to the volume of "net PRMR" of an LSE in a singular LBA. No additional studies are required.

Option 2: Firm Transmission Service. The MP of the BTMG can apply for Point-to-Point or Network Integration Transmission Service using a type of "Monthly" or "Yearly" depending on the Point of Interconnection (POI). A BTMG with a POI on the distribution system can utilize "Yearly" type firm Transmission Service to facilitate a system impact study, if required. A BTMG with a POI on the Transmission System can use "Monthly" or "Yearly" type of firm Transmission Service since an ERIS study would have been completed. A Network Customer may designate a BTMG as a Network Resource through OATI OASIS utilizing firm Transmission Service.

Option 3: Interconnection Service of NRIS or External NRIS (E-NRIS). The MP of the BTMG can enter the Generator Interconnection Queue and apply for NRIS or E-NRIS. An MP can apply for E-NRIS with a BTMG that has a POI on the distribution system. A BTMG with a POI on the Transmission System is eligible for NRIS. The BTMG would be part of a MISO Definitive

Planning Phase (DPP) study and required to submit an application and deposits as appropriate. Refer to BPM-015 Generation Interconnection for additional details.

Option 4: Historical determination of deliverability. BTMG used to offset an LSE's Initial PRMR located in the same LBA and historically demonstrated deliverability prior to integration with MISO, as accepted by MISO or a Transmission Owner, is considered deliverable. Individual BTMGs may have demonstrated deliverability by confirmation by a Network Customer as a designated Network Resource or completion of a Market Transition Deliverability test prior to an LSE joining MISO.

4.2.6.6 *Measurement and Verification of BTMG*

See Attachment TT of the Tariff and BPM-026 Demand Response.

4.2.7 Demand Resource (DR) – Qualification Requirements

MPs with DR can qualify the DR as an LMR by:

- Submitting monthly availability (in megawatts) and notification time (in hours) for the upcoming Planning Year.
- Registering the reduction capability of the DR excluding transmission losses, consistent with conditions at MISO's seasonal Coincident Peak.
- Confirming through the registration process such DR can be available to reduce Demand with no more than six (6) Hours advance notice from MISO or the LBA and sustain the reduction in Demand for a minimum of four (4) consecutive Hours.
- Confirming through the registration process that the total DR load reduction is not exclusively accomplished and dependent on the dispatch of a BTMG owned or operated by a wholesale or retail customer.
- Confirming through the registration process that the DR is equal to or greater than 100 kW (an aggregation of smaller resources within an LBA that can reduce Demand may qualify in meeting this requirement if they are within the same Load Zone CPNode).
- Confirming through the registration process that the DR is capable of being interrupted at least the first (5) times during the Summer and Winter and at least (3) times as needed during the Spring and Fall as needed by MISO or the LBA for Emergency purposes, consistent with the registration information of the physical capability of the DR.

- Confirming that the Market Participant has the authority to reduce demand using the DR. In the case of an ARC registering a DR, this would include uploading into the MECT registration a copy of the signatory pages between the ARC and the load asset customers. MISO does not accept an attestation by the ARC as an artifact to demonstrate the Market Participant possesses ownership or equivalent contractual rights in a Demand Resource.
- Documenting in the MECT the DR's capability to reduce demand to a targeted Demand reduction level or firm service level at the MISO seasonal Coincident Peak. All DR owners should demonstrate Demand reduction capability of at least 50% of their registered capability via Scheduling Instructions from a MISO Event or conduct a real power test for accreditation and provide a procedure document detailing the steps followed to implement the Demand reduction. Additional details regarding the demonstration of Demand reduction capability are in section 4.2.7.8 below. If a DR opts not to demonstrate Demand reduction capability for accreditation, one of the following options may be used for accreditation:
    - Provide documentation from the state that has jurisdiction accrediting the DR program. Additionally, if not specified in the state documentation, provide documentation supporting the capacity of the DR being registered.
    - Verification from a third-party auditor that is unaffiliated with the MP that documents the DR's ability to reduce to the targeted Demand reduction level or firm service when called upon to perform by MISO or the LBA.
    - If past performance data does not exist to demonstrate Demand reduction capability, then a mock test can be provided. The mock test should show:
        - The Demand resource's seasonal meter data from the previous planning year. New resources can provide documentation supporting estimated seasonal Demand.
        - Documentation showing a mock execution or drill of implementing the Demand resource without implementing the Demand reduction.
    - Accreditation documentation, including past performance data, mock test, third party audit, or state commission documentation, supporting the MW being registered should be from the calendar year (January 1 to December 31) immediately preceding the applicable Planning Year. Renewed registrations must submit revised documentation on an annual basis for accreditation.
- If the DR opts out of demonstrating Demand reduction capability via Scheduling Instruction or a real power test, then the DR will be subject to three (3) times the

underperformance penalties during a MISO Emergency event. Specifically, undelivered MWs will be penalized at a rate of LMP times three (3), rather than LMP. The RSG component of the penalty will not be multiplied times three (3), nor will any capacity penalties or lost capacity revenue. Only a DR with a regulatory restriction will be eligible to waive the penalty.

- Documenting in the MECT the Measurement and Verification (M&V) protocol that will be used to determine if such DR performed when called upon by MISO or the LBA during Emergencies. A DR that is sensitive to temperature changes must identify the extent of such temperature sensitivity with sufficient detail to enable MISO to verify whether the DR would be subject to the penalties set forth in Section 69A.3.9 of the Tariff. Temperature sensitivity must at a minimum include identifying the measure used for temperature changes and elasticity of the LSE's load to weather. An MP that registers a DR as a Planning Resource must confirm that the DR is able to meet all of the requirements in Section 69A.3.5 of the Tariff.
- DR that has been retired prior to the Planning Year will not qualify as a Planning Resource.
- For every season an MP registers a DR, the underlying customer accounts for ARC registrations must be registered under a single DR registration name for every season in which it is registered. The registered capability and tested status can be different for each Season.

4.2.7.1 *Demand Resource Registration Process*

DR can be registered to be used as a Planning Resource and receive SAC MW that can be converted to ZRCs.

Submission of new DR Registrations

An MP may register new DR via the Registration screen in the MECT by March 1 prior to the Planning Year. To guarantee new Planning Resources can be used in an LSE's FRAP or RBDC Opt Out, registrations of a DR intended to be used in a FRAP or RBDC Opt Out should be submitted no later than February 15 prior to the Planning Year. The registering entity must be an MP prior to registering a DR. Any entity that is not a MP, but desires to register a DR, should contact the Customer Registration team at MISO Help Center (https://help.misoenergy.org/) to become a MP. The MP will be required to certify that the registration information is accurate, complete, and that the qualified MWs from the DR are not being registered by another party. Appendix D – Registration of DRs contains the information that must be submitted by an MP through the MECT Registrations screen. MISO will review the DR registration information for

completeness, accuracy, and ensure it complies with the qualification requirements for DR. MISO will endeavor to review the registration within 15 days after the registration was submitted to determine whether the DR has been accredited as an LMR, or whether there are any deficiencies that must be corrected. If the DR is accredited as an LMR, it will be given a unique name for tracking purposes and made available in the MECT screens for use by the MP.

Submission of ARC (Aggregator of Retail Customers) **LMR Registrations**

The LBA and LSE will verify the following:

- LBA name
- LSE name
- RERRA name
- CPNode name
- End use customer account number
- Meter identification number(s)
- Maximum level of participation (MWs)
- Address of the assets in the ARC registration.

The maximum level of participation for each asset within an LMR resource should be no greater than that asset's load as evaluated by the LBA or LSE.

The assets' load should be calculated as the average load of the assets up to the last three years' seasonal MISO system peak hours. One or two years of load data may be used if the full three years is not available, but an explanation must be submitted as to why the full three years are not available. For example, a new facility that has only been in operation for two years would be a reason less than three years of load data is accepted.

It is the responsibility of the Market Participant to provide an explanation which demonstrates why historical average peak load is not representative of expected future peak load for an asset and propose an alternative method of calculating the maximum level of participation for review and approval by MISO and the LSE.

If during registration review, the LBA or LSE is identified to be incorrect for assets in a registration, the registration will be rejected. The Market Participant can submit a new registration once the Market Participant has identified the correct LBA or LSE. This will restart the review timeline for MISO, the LBA, the LSE, and RERRA.

Any modification to the assets during the review will restart the review timeline for MISO, the LBA, the LSE, and RERRA.

Instances where the ARC LMR's customer changes LSEs:

- The LSE identified by the ARC LMR should be correct at the time of the ARC LMR's registration submitted to the Module E Capacity Tracking (MECT) tool. Otherwise, the ARC LMR Registration will be rejected.
- If the ARC LMR's LSE changes during the registration process, the ARC LMR registration can be revised. The date the registration was submitted will be sent along to the LSE for their review.
    - It is the responsibility of the ARC LMR's customers and the ARC to identify LSE changes.
    - It is the responsibility of the ARC LMR to notify MISO, the old LSE, and the new LSE when changes to the ARC LMR's customer's LSE occur.

4.2.7.2 *Termination of Demand Resource Accredited as LMR*

Because DRs need to be accredited annually, the "Effective Stop Date" will default to the last day of the applicable Planning Year.

4.2.7.3 *Amendments to Accredited DR Registration Data*

The Market Participant can amend the registration for a DR for an existing upcoming Planning Year by providing MISO notification no later than March 1, if the original registration was submitted by the February 1 due date.

The MP may modify any of the non-end date information submitted in the registration, which may affect the DR's qualification, including, but not limited to, a change in operation, number of interruptions, advisory notice period, maximum duration, or accreditation amount as either an increase or decrease in either its targeted MW level or firm service level. The MP shall submit registration information in the MECT Registrations screen by March 1 prior to the Planning Year for MISO to determine whether the resource still qualifies as an LMR.

4.2.7.4 *Renewal of DR for subsequent Planning Years*

A DR must be reviewed annually for accreditation as an LMR. A MP can request renewal of DR accreditation for subsequent Planning Years through the MECT Registrations screen. Renewal of DR must be requested by February 1 prior to the Planning Year. MISO will review the renewed DR registration information for completeness and accuracy and ensure it complies with the qualification requirements for DR. MISO will endeavor to notify the MP within 15 days after the renewed registration form was submitted regarding whether the DR has been accredited as an LMR, or whether there are any deficiencies that must be corrected. If the DR is accredited as

an LMR, it will be given a unique name for tracking purposes and made available in MECT for use by the MP during the applicable Planning Year. Section 4.2.7.3 Amendments to Accredited DR Registration Data rules also apply to renewed DRs in subsequent Planning Years.

4.2.7.5 *Demand Resources – SAC Determination*

A Demand Resource must be registered and accredited with MISO and will receive 100 percent of its capacity rating for the Planning Year. Seasonal capacity values for Demand Resources will be based on documentation from the state, third party auditor, past performance, or mock test consistent with their ability at MISO's seasonal Coincident Peak Demand. Since DR is a reduction in Demand, SAC is adjusted upward by applying the MISO PRM and transmission loss percentage for the LBA to the capacity rating.

4.2.7.6 *Demand Resource Deliverability*

The owner of ZRCs converted from DR may use them as part of a FRAP or RBDC Opt Out or offer them into the PRA. The DR ZRCs are considered deliverable regardless of the LRZ where the DR physically resides.

4.2.7.7 *Measurement and Verification of Demand Resource*

See Attachment TT of the Tariff and BPM-026 Demand Response.

4.2.7.8 *Demand Resource – Testing Requirements*

The testing period for a DR to demonstrate Demand reduction capability is the calendar year (January 1 to December 31) immediately preceding the applicable Planning Year unless a test deferral is submitted (see section 4.2.7.9 Demand Response Test Deferral). For example, the testing period for the 2025-26 Planning Year will be January 1, 2024 to December 31, 2024. DR shall demonstrate seasonal Demand reduction capability for a minimum of 1-hour duration with an attestation that the DR can continue the reduction for a minimum of 4 consecutive hours. Results should be submitted in accordance with LMR registration deadlines and attached to the LMR registration.

Test results should be adjusted to MISO seasonal Coincident Peak conditions. Upward adjustments shall not exceed +50% of each DR and may include, but not limited to, factors such as temperature, humidity, and/or other process load variations. Downward adjustments are allowed down to the 100kw minimum total for a DR registration. Adjustments to test results should be documented and submitted with the test results to support the capacity accreditation

for the DR. Adjustments to DR test results are subject to MISO review and approval during the LMR registration process each year.

DR are required to demonstrate performance of at least 50% of their registered seasonal capability via Scheduling Instructions from a MISO Event or conduct a real power test. If a DR is only able to demonstrate at 50% to 80% of their intended registered MW capability, an attestation from an officer of the Market Participant registering the DR, or from a financially responsible entity, must be provided to MISO during the registration process documenting the reasons for the difference between the registered capability and the demonstrated amount (i.e., industrial process, temperature, etc.). If demonstrating greater than 80% of the registered capability, the DR shall need to provide documentation supporting the adjustments made to normalize the MW capability to seasonal peak conditions.

Results may be uploaded to the documentation section of the LMR registration in MECT and may include: (1) test results including the meter data for the entire day of the tests, (2) historical meter data for 10 days around the MISO seasonal Coincident Peak with the MISO seasonal Coincident Peak as a midpoint, to calculate the capacity baseline, and (3) any other supporting documentation necessary for the LMR capability adjustment. The templates used for submitting the requested meter data may be found on the MISO public website under Markets and Operations > Demand Response.

If a DR is unable to demonstrate performance of at least 50% of the registered MW capability of the DR [only partially performs], the DR must retest the underperforming portion(s) of the DR or create separate registrations for the portions of the DR that did not exceed the 50% performance threshold. If the DR is unable to demonstrate performance of at least 50% of the registered MW capability during the testing period, the DR may still qualify for the PRA by opting out of the testing requirement, provided that the DR will then be subject to the three (3) times penalty provisions for underperformance described in Section 4.2.9 Electric Storage Resource.

If a DR underperforms during a MISO Emergency event and that event is chosen by the DR owner to satisfy the testing requirement, the tested portion of the DR will equal the actual reduction achieved during the event. If a DR only partially tests, the entire DR may be registered, however, separate registrations will be required. For example, the tested portion of the DR would be one registration and the untested portion of the DR would be another registration. If a DR is made up of an aggregation of different physical locations, each location can demonstrate performance—or elect not to—separately. Tested locations may be

aggregated together and untested locations may be aggregated together in registrations, as long as all locations are within the same Load Zone CP Node. Separate registrations for tested versus untested resources are required in order for MISO to accurately assess penalties for underperformance during a MISO Emergency event, as the untested DR would be subject to the three (3) times penalty, unless the untested DR is not required to test per qualification requirements in 4.2.9 Electric Storage Resource.

When testing a DR, accurate availability should be reflected in the DSRI by showing the DR as self-scheduled. If an MP plans to test DR greater than 20 MW, the MP should notify MISO operations two (2) Business Days prior to conducting a test by submitting the DR Testing Notification Template to the MISO ITOC (ITNOCRequests@misoenergy.org). The DR Testing Notification Template should include: (1) LMR name, (2) MP, (3) Load Zone CP Node, (4) expected MW reduction, (5) expected reduction date and hour(s), (6) notification time, and (7) operator contact information in case MISO Operations has questions. New DR and DR that did not clear the PRA will not be able to update the DSRI, however, these DR should still notify MISO by utilizing the DR Testing Notification Template.

4.2.7.9 Demand Response Test Deferral

The MP must provide written notification to MISO (https://help.misoenergy.org) of their intention to defer Demand Response testing by February 1 prior to the upcoming Planning Year. This DR Testing Deferral Notice must be from an officer of the company and include the following information:

- Company Name
- NERC ID of Company
- Planning Resource Name
- Local Balancing Authority (LBA) or External Balancing Authority (BA) where located
- Expected DR test value (MW)
- Estimated completion date of DR test

Once the DR test is completed, information pertaining to it must be submitted via written notification to MISO (https://help.misoenergy.org).

A Demand Resource providing such notice must satisfy credit requirements by March 1 prior to the Planning Year totaling the ICAP value registered, but not tested, multiplied by $2,400/MW, where $2,400 is the product of 3 * 4 * $200 to account for the three (3) times Energy penalty assumed under the waiver, the four (4) hours of LMR requirements, and a $200 LMP as a proxy for pricing under emergency conditions.

If the Market Participant submits the real power test results on or before the last business day of the month prior to the Season the DR was used in a FRAP or RBDC Opt Out or cleared the auction within the Planning Year that are equal to or greater than the expected DR test value, then the Transmission Provider will adjust the Market Participant's credit requirement to account for these changes within twenty (20) Business Days after that real power test is submitted.

If SAC associated with a Planning Resource for which DR testing has been successfully deferred are unconverted to ZRCs, the Market Participant may provide notice to the Transmission Provider that it wishes to forfeit the deferred DR value, in which case the Transmission Provider will adjust the Market Participant's DR value and credit requirement within twenty (20) Business Days.

A Market Participant that provides a DR Test Deferral Notice and that either (1) has not submitted any real power test result for such DR by the last business day of the month prior to the Season the DR was used in a FRAP or RBDC Opt Out or cleared the auction within the Planning Year, or (2) has submitted a real power test result by the last business day of the month prior to the Season the DR was used in a FRAP or RBDC Opt Out or cleared the auction within the Planning Year that demonstrates fewer megawatts are available than the expected DR test value submitted in the DR Test Deferral Notice, shall be subject to a penalty equal to three (3) times the Hourly Real-Time Ex Post LMP at the Load CPNode for any such deficiency and distributed pursuant to the Market Participants representing the LSEs in the Local Balancing Authority Area(s) that experienced the Emergency that required the use of an LMR. Such revenues shall be distributed on a Load Ratio Share basis. In addition, such Market Participant shall not have their credit released until a real power test result demonstrating the availability of all megawatts submitted in the DR Test Deferral Notice is submitted and verified by the Transmission Provider, or the end of the Planning Year, whichever is earlier.

4.2.8 Energy Efficiency Resources

Energy Efficiency (EE) Resources are installed measures on retail customer facilities that achieve a permanent reduction in electric Energy usage while maintaining a comparable quality of service. The EE Resource must achieve a permanent, continuous reduction in electric Energy

consumption (during the defined EE Performance Hours) that is not reflected in the peak load forecasts used for the PRA for the Planning Year for which the EE Resource is proposed. The EE Resource must be fully implemented at all times during the Season within the Planning Year, without any requirement of notice, dispatch, or operator intervention. Examples of EE Resources are efficient lighting, appliance, or air conditioning installations; building insulation or process improvements; and permanent load shifts that are not dispatched based on price or other factors.

The reduction in electric Energy consumption due to existing EE programs that is reflected in the CPD forecast cannot qualify as an EE Resource. All the requirements to offer or commit an EE Resource in MISO's capacity planning market are detailed in the sections below. One of the major requirements includes the measurement and verification of the EE Resource's Nominated EE Value for a Season within the Planning Year. The Nominated EE Value is the expected average Demand (MW) reduction, excluding transmission losses, during the defined EE Performance Hours in each Season of the Planning Year. The EE Performance Hours are between the hour ending 13:00 Eastern Prevailing Time (EPT) and the hour ending 19:00 EPT during all days of the applicable Season the EE Resource is seeking capacity accreditation, inclusive, of such Planning Year, that are not a weekend or federal holiday.

A Measurement & Verification (M&V) plan describes the methods and procedures for determining the Nominated EE Value of an EE Resource and confirming that the Nominated EE Value is achieved. The EE Resource provider must submit an initial Measurement & Verification plan for the EE Resource by February 1 prior to the PRA in which the EE Resource is to be initially offered. The EE Resource provider must submit an updated Measurement & Verification plan for the EE Resource by February 1 prior to the next PRA in which the EE Resource is to be subsequently offered. Post-installation of the EE Resource, the EE Resource provider must submit an initial Post-Installation M&V Report for the EE Resource by March 1 prior to the first Planning Year that the EE Resource is committed to PRA. The EE Resource Provider must submit updated Post-Installation M&V Reports by March 1 prior to each subsequent Planning Year that the resource is committed. Failure to submit an updated Post-Installation M&V Report by March 1 prior to a subsequent Planning Year or failure to demonstrate that post-installation M&V activities were performed in accordance with the timeline in the approved M&V Plan will result in a Nominated EE Value equal to zero MWs of seasonal ZRCs for the Planning Year.

The last Post-Installation M&V Report submitted and approved by MISO prior to the Planning Year that the EE Resource is committed will establish the Nominated EE Value that is used to

measure PRA commitment compliance during the Planning Year. Details regarding seasonal PRA commitment compliance and the associated penalty for failure to deliver the unforced value of a seasonal PRA capacity commitment are detailed below.

MISO reserves the right to audit the results presented in an initial or updated Post-Installation M&V Report. The M&V Audit may be conducted at any time, including during the defined EE Performance Hours. If the M&V Audit is performed and results finalized prior to the start of a Planning Year, the Nominated EE Value confirmed by the Audit becomes the Nominated EE Value that is used to measure seasonal PRA commitment compliance during the Planning Year. If the M&V Audit is performed and results are finalized after the start of a Planning Year, the Nominated EE Value confirmed by the M&V Audit becomes the Nominated EE Value prospectively for the remainder of that Planning Year.

Energy Efficiency installations that are installed prior to any given Planning Year are eligible to participate in seasonal PRAs or be used in a FRAP or RBDC Opt Out for that Planning Year and three subsequent Planning Years. For example, an EE Resource installed and qualified prior to June 1, 2013, could participate in the seasonal PRAs or be used in a FRAP or RBDC Opt Out for 2013/14, 2014/15, 2015/16, and 2016/17 Planning Years provided the EE Resource registers and meets the qualification requirements for each Planning Year. After four years, the EE Resource could no longer be used as a Planning Resource but would continue to be included as a reduction in the Demand forecast.

4.2.8.1 *Energy Efficiency Resource – Measurement and Verification*

See Attachment UU of the Tariff.

4.2.9 Electric Storage Resource

An Electric Storage Resource (ESR) is a resource capable of receiving electric Energy from the grid and storing it for later injection of Energy back to the grid. The ESR includes all technologies and/or storage mediums, including but not limited to, batteries, flywheels, compressed air, and pumped storage. The location of an ESR may be at any point of grid interconnection, on either the Transmission System or a local distribution system. An ESR must:

- be capable of injecting a minimum of 100 kW;
- be capable of complying with MISO's Setpoint instructions;
- have the appropriate metering equipment installed; and

- be physically located within the MISO Balancing Authority Area.

4.2.9.1 *Electric Storage Resource - Qualification Requirements*

An ESR may qualify as a Capacity Resource for the Planning Resource Auction (PRA) provided the resource is a Use Limited Resource that is able to continuously discharge for a minimum of 4 hours across the expected peak hour each Operating Day and meets the following criteria:

- An ESR must demonstrate discharge capability during each of the seasonal auctions the ESR will be used to meet RAR.
- Verification of capability will be based on the power (MW) and the Energy rating (MWh) via data included in a populated Non-GADS Performance Template and submitted to MISO through the MECT.
- For an upcoming PRA, the following data for the ESR must be submitted to the MECT by October 31 to qualify for the PRA using the Non-GADS Performance Template: Nameplate Capacity, Net Energy Rating (MWh), and Hourly Equivalent Discharge Amount (MW) from the ESR testing (minimum of 1 hour and a maximum of 4 hours).
- An ESR must demonstrate deliverability in order to qualify as a Capacity Resource for participating in the PRA. If an ESR is interconnected to the MISO Transmission System, the Resource can either obtain Network Resource Interconnection Service (NRIS) under Attachment X or procure Firm Transmission Service in conjunction with Energy Resource Interconnection Service (ERIS). If an ESR is interconnected to the Distribution System, the Resource will be subject to coordination with Distribution Provider, Transmission Owner, and MISO Transmission Service. For more information, see section "4.2.8.5.1 - Roles and Responsibilities to Determine Eligibility for PRA Participation."

4.2.9.2 *Electric Storage Resource - Hourly Equivalent Discharge Amount (MW)*

The Hourly Equivalent Discharge Amount (MW) of an ESR will be calculated as:

$$\frac{Total\ Net\ Energy(MWh)}{Total\ Hours\ tested}$$

where The Total Net Energy Rating (MWh) and the Total Hours tested are based on the data submitted to MISO through a populated Non-GADS Performance Template.

4.2.9.3 *Reporting Historical Data*

Market Participants will use MISO's Non-GADS Performance Template found on the Resource Adequacy page of the MISO website to submit the appropriate unit and operational data for the upcoming Planning Year. A populated Non-GADS Performance Template must be submitted to MISO by October 31 of each year via the Module E Capacity Tracking (MECT) tool to be eligible for accreditation in the Planning Resource Auction applicable to the following Planning Year.

Reporting availability data for an ESR is not required if the ESR has less than 10 MW of nameplate capacity and the Market Participant has never provided such data for the ESR.

4.2.9.4 *ESR Capacity Accredited Value Determination*

MISO will determine the accreditation for each ESR based upon an evaluation of its demonstrated capability, resource availability, and Interconnection Service if applicable. ESRs must demonstrate deliverability prior to participating in the PRA. Deliverability will be demonstrated by the Market Participant and verified by MISO depending upon the Point of Interconnection of the resource. A class average unavailability rate will be applied to an ESR to determine a default class average capacity accreditation value prior to being in service long enough to calculate a unit-specific forced outage rate. A 5% unavailability rate will be assumed until sufficient ESRs exist (30 or more individual units) to come up with an average value. The accreditation of an ESR with sufficient historical data is calculated through the Non-GADS Performance Template.

4.2.10 Qualifying Facilities (QF)

Certain generators may be recognized as a Qualifying Facility under PURPA. MISO offers three modeling options that facilitate market participation for QF generators. Each of the options, described below, are reflected differently in the PRA. Each QF should coordinate with its LSE to determine eligibility.[1]

Gross Modeling: Load and generation associated with a QF are modeled separately in the PRA. Load associated with the QF would be included in the LSE's Demand forecast submitted to MISO and generation is modeled as a Generation Resource with a CPNode. QF generators utilizing this option are required to meet the accreditation requirements for testing and

[1]Additional details can be found in MISO's Qualifying Facilities White Papers on the MISO website. Markets and Operations-> Markets and Operations-> Whitepapers.

deliverability as described in Section 4.2.1 Generation Resource but not Dispatchable Intermittent Resource or Intermittent Generation.

Hybrid Modeling: When QF generation exceeds the associated QF load, both load and generation may be modeled as a single Generation Resource CPNode. The expected net injection onto the transmission system (e.g., QF generation – process load served by QF generation) is modeled as the GVTC. QF generators utilizing this option are required to meet the accreditation requirements for testing and deliverability as described in Section 4.2.1 Generation Resource but not Dispatchable Intermittent Resource or Intermittent Generation.

BTMG Modeling: Load and generation associated with a QF are modeled separately in the PRA. Load associated with the QF would be included in the LSE's Demand forecast submitted to MISO and generation is modeled as a BTMG. QF generators utilizing this option are required to meet the accreditation requirements for testing and deliverability as described in Section 4.2.6 BTMG Qualification Requirements.

4.2.11 Hybrid and Co-Located Resources

For purposes of accreditation, Hybrid Resources and Co-Located Resources will be accredited in two phases: Phase I – Sum of Parts accreditation and Phase II – Availability-based accreditation. Phase I applies in the initial service life of a Hybrid Resource or Co-Located Resource before operating history is available. Phase II applies once a Hybrid Resource or Co-Located Resource has historical operating data. See Appendix X – Hybrid and Co-Located Resource Accreditation for details.

4.3 Confirmation and Conversion of SAC MW

A ZRC represents 1 MW-day of qualified Seasonal Accredited Capacity (SAC) from a Planning Resource for a specific Season of a Planning Year, tracked to the nearest tenth of a MW, pursuant to the applicable ZRC qualification procedures described herein. To create a ZRC, an MP must confirm the SAC MW and then convert SAC MW from each qualified Planning Resource to seasonal ZRCs through the Convert SAC screen in MECT. SAC confirmation and conversion must be completed per the timeline specified in appendix K.

When seasonal ZRCs are converted from SAC by the Asset Owner, the seasonal ZRCs are populated into the available ZRC account for that Asset Owner. MISO will keep track of how many ZRCs the MP has created, and how many remaining SAC MWs for each Planning Resource are available for conversion to ZRCs. Once created, MISO will track ZRCs back to the

specific Planning Resources that they were created from to assist with establishing clearing requirements, the auction clearing process, and market mitigation monitoring.

4.4 ZRC Transactions

4.4.1 Transfer of ZRCs

Available ZRCs can be transferred between MPs using the MECT. This is accomplished in the 'ZRC Transactions' tab in the MECT. Both the 'Buyer' and 'Seller' are required to account for a ZRC transaction in the MECT. The 'Seller' is required to submit the transaction in the MECT and the 'Buyer' is required to confirm the transaction reported. Once the transaction has been submitted and confirmed by both parties, the ZRC transaction volumes will be subtracted from the seller's available ZRC account and added to the buyer's available ZRC account. ZRC transactions are from the transaction date to the end of that Season. In situations where the ZRC transaction is only intended for part of a Season, the ZRCs can be transferred back to the original MP and would be effective for the rest of the Season. The Market Participant that registered the Planning Resource is responsible for complying with all Tariff requirements. The MECT allows transactions based the ZRC balance in the Seller's portfolio. ZRC transactions can occur throughout the PRA auction cycle, including during the Offer window. ZRC transactions can also be utilized during the Planning Year to facilitate ZRC replacement transactions.

a. ICAP Deferral

i. Summary

ICAP Deferrals allow Market Participants (MPs) to participate in the Planning Resource Auction (PRA) using Zonal Resource Credits (ZRCs) that have been credited to the following:

For Schedule 53 Resources:

- an untested new Planning Resource;
- new Schedule 53 Resources that have not or will not achieve the Commercial Operation Date (COD) by March 1 prior to the upcoming Planning Year, an existing Planning Resource that is returning to operation from a catastrophic outage or suspension; an existing Planning Resource where the Market Participant's GVTC extension request was denied or the Market Participant missed the GVTC submittal deadline and failed to request an extension;
- an existing Planning Resource that is returning to the MISO market.
- For Non-Schedule 53 Resources:
- an untested new Planning Resource;

- new Non Schedule 53 Resources that have not or will not achieve the Commercial Operation Date (COD) by March 1 prior to the upcoming Planning Year
- an existing Planning Resource that is returning to operation from a catastrophic outage or suspension;
- an existing Planning Resource increasing its capability through increases to GVTC or Interconnection Service (IS);
- an existing Planning Resource where the Market Participant's GVTC extension request was denied or the Market Participant missed the GVTC submittal deadline and failed to request an extension;
- an existing Planning Resource that is returning to the MISO market.
-

Schedule 53 Resources that submit ICAP Deferral will get SAC class average for the deferred season(s) while non-Schedule 53 Resources will get the lesser of GVTC or IS, multiplied by (1-class average XEFORd).

ii. Requirements and Timeline

The MP must provide written notification to MISO (https://help.misoenergy.org) of its intention to defer ICAP by February 15 prior to the upcoming Planning Year. This ICAP Deferral Notice should state that the Planning Resource will demonstrate deliverability, demonstrate commercial operation including filing a COD Notification (Appendix E to the GIA) with MISO Resource Integration (ResourceIntegration@misoenergy.org), have confirmed Transmission Service , and/or perform a real power test to submit its GVTC after March 1, but before the last Business Day, prior to the start of the deferred Season. The ICAP Deferral Notice can be found in Appendix T of this BPM. The ICAP Deferral Notice must be from an officer of the company and include the following information:

- Company Name
- NERC ID of Company
- Planning Resource Type
- Planning Resource Name/CPNode Name/Unit Number
- Local Resource Zone (LRZ) or External Resource Zone (ERZ) where Planning Resource is located
- Planning Resource Fuel Type
- Estimated ICAP Value in MW
- Estimated Completion Date of ICAP
- Reason for deferring (See Appendix U)Season(s) to be deferred

- Generator Interconnection Agreement (GIA) Number (only necessary if deferral includes upgrades to Interconnection Service)
- Expected NRIS and ERIS values
- GVTC / COD declaration for intermittent resources
- Commercial Operation Date
- TSR Number
- Other ICAP Type

Once the GVTC test is completed, information pertaining to it must be submitted via written notification to MISO (https://help.misoenergy.org/) by the last Business Day prior to a Seasons' start date for all deferred ZRCs that cleared in the PRA or were included as part of a FRAP or RBDC Opt Out. For intermittent resources COD declaration is used to meet the GVTC submittal requirement. For intermittent BTMG an attestation of COD must be submitted to MISO.

New resources must have (i) an executed GIA or an unexecuted GIA accepted by FERC and (ii) be registered in the June Commercial Model prior to the upcoming Planning Year at the time of the ICAP Deferral request. For modeling SAC in the PRA, the resource must be modeled in the March model prior to the PRA in order to offer into the PRA accordingly. For example, the resource needs to be in the March 2025 Commercial Model to participate in the 2025-2026 Planning Resource Auction.

The MP requesting the ICAP Deferral must post 90 days of credit for the ICAP value of the untested ZRCs no later than March 1 prior to the upcoming Planning Year. The credit will be based on the 90 days of daily CONE for the LRZ in which the resource is located.

MISO will adjust the Market Participant's credit requirements within ten (10) Business Days of the full ICAP being met and has been validated by MISO or when the MP provides written notification to MISO Resource Adequacy that a Planning Resource replacement has been completed.

4.5.3 Uncleared ZRCs with ICAP Deferrals

If the untested ZRCs will not be used in a FRAP or RBDC Opt Out or will not be offered into the PRA, the MP that registered the resource may provide notice to MISO by March 1 that it wishes to forfeit the deferred ICAP value. MISO will recalculate the resulting Seasonal Accredited Capacity (SAC) value and will adjust the credit requirements within ten (10) Business Days after

receiving the notice. Furthermore, if the untested ZRCs do not clear the PRA, MISO will release credit back to the MP that submitted the ICAP Deferral Notice.

4.5.4 ICAP Deferral Non-Compliance Charge

The MP that submitted the ICAP Deferral request is responsible for completing ICAP or resource replacement by the last Business Day of prior to a Seasons' start date for all deferred ZRCs that cleared in the PRA or were included as part of a FRAP or RBDC Opt Out. Any ICAP not completed or replaced by the last Business Day prior to a Seasons' start date will be subject to the ICAP Deferral Non-Compliance Charge for each day the ICAP or the Planning Resource replacement is not completed.

The ICAP Deferral Non-Compliance Charge will be based on the sum of the applicable seasonal Auction Clearing Price (ACP) and daily CONE based on the LRZ or ERZ of the Planning Resource, multiplied by the number of ZRCs that have not been replaced or tested.

The distribution of ICAP Deferral Non-Compliance Charge will be allocated pro-rata based on each LSE's share of the total seasonal Final Planning Reserve Margin Requirements (PRMR) in MISO.

Please refer to Appendix U for Examples of ICAP Deferrals.

5 Resource Adequacy Requirements

5.1 Overview

MISO's Resource Adequacy construct ensures that adequate Planning Resources are maintained for each Local Resource Zone (LRZ) to meet the MISO footprint's seasonal Final Planning Reserve Margin Requirement (Final PRMR). An LSE can meet its seasonal Final PRMR by any of the following ways:

1) Self-scheduling of ZRCs
2) Fixed Resource Adequacy Plan (FRAP)
3) Participating in the Planning Resource Auction (PRA)
4) Paying the Capacity Deficiency Charge (CDC)
5) Reliability Based Demand Curve Opt Out (RBDC Opt Out)

5.2 Local Resource Zones

MISO developed Local Resource Zones (LRZ) to reflect the need for an adequate amount of Planning Resources to be in the appropriate physical locations within the MISO Region to reliably meet Demand and LOLE requirements. MISO will provide the details of each LRZ no later than September 1 of the year prior to a Planning Year. The geographic boundaries of each of the LRZs will be based upon analysis that considers: (1) the electrical boundaries of Local Balancing Authorities; (2) state boundaries; (3) the relative strength of transmission interconnections between Local Balancing Authorities; (4) the results of previous LOLE studies; (5) the relative size of LRZs; and (6) market seams compatibility. MISO may re-evaluate the boundaries of LRZs if there are changes within the MISO Region including, but not limited to, any of the preceding factors, significant changes in membership, the Transmission System and/or Resources.

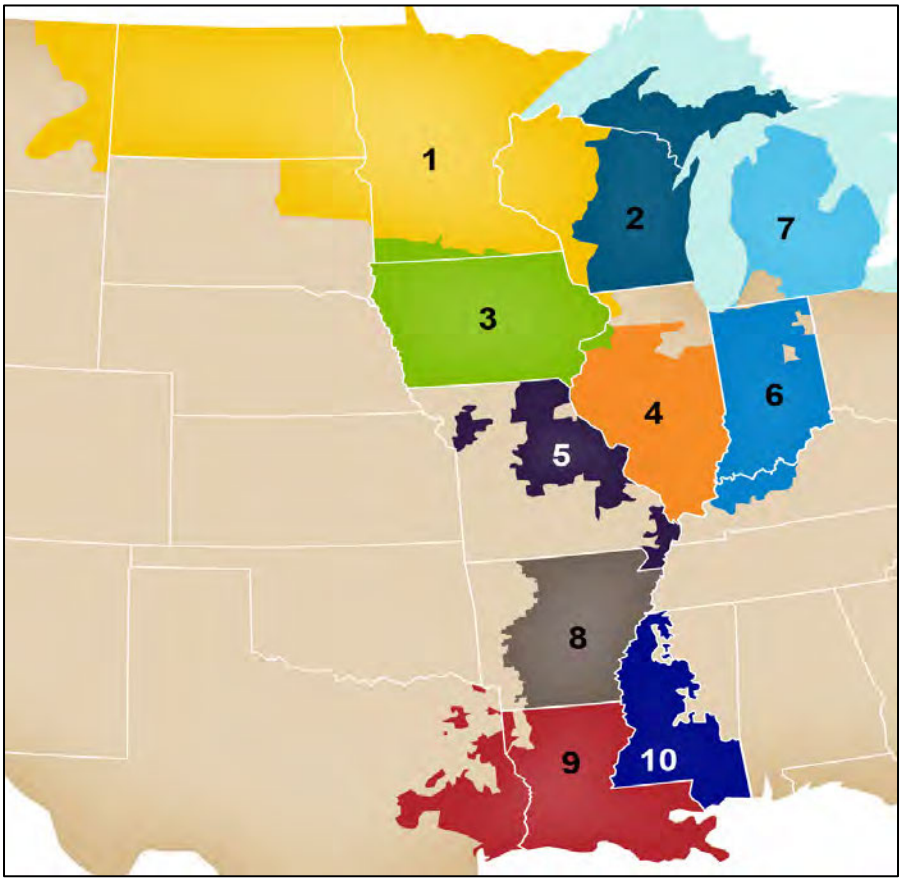


Figure 5: Local Resource Zones Map

5.2.1 Change in LRZ Configuration

MISO, after working with stakeholders and submitting a Tariff revision to Attachment VV that has been accepted by the Federal Energy Regulatory Commission, may change the configuration of the LRZs if a re-evaluation trigger has occurred and after consideration of the criteria outlined for consideration in setting LRZ boundaries. Changes to LRZ configuration will only be applicable to future Planning Years that have not already been cleared through the PRA. MISO will share any re-evaluation triggers and the results of the analysis documenting the impacts of the proposed LRZ boundary changes with stakeholders in an open and transparent manner prior to making any filings to change LRZ boundaries.

Once the boundaries of an LRZ have changed, its boundaries should stay constant for at least three years to provide stable future locational signals.

5.2.1.1 Re-evaluation Triggers

The Transmission Provider may re-evaluate the boundaries of LRZs if there are significant changes in the Transmission Provider Region. Such changes are called re-evaluation triggers, and they include, but are not limited to, the following:

1) Significant changes in membership:
   Re-evaluation may occur for LRZs where there are membership changes in the MISO system or for areas which neighbor the regions where there is a membership change. Re-evaluation may occur prior to or in the cycle immediately following the integration of new members into the MISO system.
2) Significant changes in the Transmission System:
   Transmission infrastructure must be on target to be in-service by June 1 of the year which would follow a filing for an LRZ boundary changes (i.e., the transmission must be in-service for the first summer where the zonal changes will go into effect). The changes to the transmission system should impact transmission constraints represented in the MISO Resource Adequacy construct for the zone(s) being reevaluated.
3) Significant changes in Resources:
   Changes to the resource mix may include the addition of significant new generation or the retirement of significant existing generation. The resource changes should be shown to modify the transmission system flows in the zone(s) being studied, impacting transmission constraints represented in the MISO Resource Adequacy construct.

The existence of a trigger will not guarantee that a zonal change will be implemented; the trigger will allow the analysis to proceed and will be considered as part of the final decision on whether or not to change zonal boundaries.

5.2.1.2 Re-evaluation Considerations

Once a re-evaluation trigger has been met, the geographic boundaries of the zone or zones may be re-evaluated. This re-evaluation will be based upon an analysis that considers the following factors.

1) Electrical Boundaries of Local Balancing Authorities
2) State boundaries
3) Relative strength of transmission interconnection between Local Balancing Authorities

4) Results of LOLE studies
5) Relative Size of LRZs
6) Natural geographic boundaries such as lakes and rivers

The electric boundaries of Local Balancing Authorities, state boundaries, and natural geographic boundaries will be considered by inspection. Additional information on the process used to analyze the other criteria is below.

Relative Strength of Transmission Interconnections between Local Balancing Authorities
Multiple aspects of the transmission system are considered in this portion of the evaluation. These aspects are first investigated individually, and the final assessment considers all of the factors. The assessment includes the following:

- Previously identified LOLE results (Capacity Import and Export Limit constraints)
- Constraint variation(s)
- Transmission projects
- Physical ties including post-contingency connectivity and transmission service

LOLE results identified for Capacity Import and Export Limit analysis before and after the boundary change is applied will be considered. Zonal transfer analysis yields a list of constraints. The most limiting constraint after redispatch determines a zone's limit in the LOLE study. In the re-evaluation analysis, the less limiting constraints are also considered since reconfigurations impact the transfer level at which constraints are limiting. Also, while there can only be one limiting constraint, multiple constraints can be seen at similar transfer levels. For example, assume the most limiting constraint is at a transfer level of 100 MW. There are two additional constraints at 99 MW and one at 90 MW. Since these transfer levels are very close, all four are considered in this evaluation.

Constraint variation is caused by reconfiguration of Local Resource Zones. This variation is caused by changing the generation that is used to create the transfer. Zonal definitions determine which generators are used in the transfer analysis so any change in zonal definition may result in a difference in the impact the transfer has on the constraint. It is possible that a constraint has an impact above the threshold before reconfiguration and less than the threshold afterwards which is considered in this evaluation.

The impact of approved MTEP Appendix A and Target A transmission projects is considered. If a project mitigates a constraint and the project is expected to be in service prior to the Planning

Year under consideration, then the impact of the transmission project to the LOLE results is considered.

MISO will consider the number of ties of any reconfigured zone. Generally, a reconfigured zone should have two or more ties with the rest of MISO. Two or more ties between the zones are optimal when planning for contingencies so the zones are still connected post-contingency. Any LBA being added to an existing LRZ should have two or more ties with an LBA in the new LRZ. Any other impacted LRZs should have contiguous LBAs with two or more ties. Further consideration is needed if an LBA leaving an LRZ results in an LRZ with unconnected LBAs. In addition, confirmed transmission service between zones may be considered when evaluating reconfigurations. Confirmed long-term transmission service indicates transmission capacity between the zones has been previously evaluated.

The Results of LOLE Studies
LOLE studies will be performed with the LRZ configuration being considered. The results of this analysis will be compared with the prevailing LRZ configuration. This LOLE analysis includes a MISO PRM model analysis (Section 3.5), LRZ LRR determination (Section 5.2.2.2), and capacity import and export limit analysis (Section 5.2.2.1) for the LRZ configuration being considered and for the prevailing LRZ configuration. The results of this analysis and comparison with the prevailing system results will be used as one factor in determining whether LRZ changes are warranted, in conjunction with the other LRZ considerations.

Relative size of LRZs
The relative size of an LRZ will contain no less than 2,000 MW of Demand.

5.2.1.3 Determination of LRZ Boundaries

Following the determination of an LRZ re-evaluation trigger, the conclusion of all analysis with consideration of stakeholder feedback will determine whether the LRZ boundaries will be changed. This determination will be based upon the benefits and/or risks that the LRZ boundary changes would present on the system. MISO's final determination will be shared with stakeholders and the changes will be filed with FERC.

5.2.1.4 External Resource Zones

MISO developed External Resource Zones (ERZs) to reflect the physical location of External Resources and establish Auction Clearing Prices for such External Resources (other than

Coordinating Owner and Border External Resources). An ERZ will be created for each External Balancing Authority adjacent to MISO with Planning Resources participating in the MISO PRA. Current External Resource Zones:

ERZ	Area(s)
EZ20	KCPL, OPPD, WAUE
EZ22	PJM
EZ23	OVEC
EZ24	LGEE
EZ26	AECI
EZ27	SPA
EZ28	TVA

External resources ZRCs are counted toward the MISO North/Central region and the MISO South region based on transmission shift factors that are calculated annually.

5.2.1.5 Establishing Sub-Regional Resource Zones (SRRZ)

MISO will also establish SRRZs applicable for each Planning Year. A SRRZ is a zone, comprised of an LRZ or combination of two or more LRZs, to administer constraints in accordance with applicable seams agreements, coordination agreements, or transmission service agreements.

Currently, MISO has two SRRZs: MISO South, defined as LRZs 8, 9 and 10, and MISO Midwest, defined as LRZs 1-7. These SRRZs are a result of the settlement agreement between MISO, SPP, and the other Joint Parties. This agreement established Regional Directional Transfer Limits (RDTL) that limit the amount of total transfer between these two SRRZs in the PRA. The RTDL from South to Midwest is 2,500 MW and the RTDL from the Midwest to South is 3,000 MW.

MISO shall establish the Sub-Regional Export Constraint (SREC) and Sub-Regional Import Constraint (SRIC) for each Season by March 1 prior to the Planning Year. The methodology for determining the SREC and SRIC for each SRRZ is described below.

1.1.1.2.4 5.2.1.5.1 Determination of Seasonal SREC and SRIC

The following steps describe the steps MISO will utilize to calculate the SREC and SRIC.

1. Begin with the Regional Directional Transfer Limits (RDTL) between the two SRRZs

2. Complete a feasibility analysis to review operational events from the previous seasonal peaks to determine if a further reduction to the Regional Directional Transfer Limit is warranted for reliability.
3. Decrement the initial RDTL (from step 1) based upon completed feasibility analysis
4. Subtract from the net RDTL (from step 3) the sum of Firm Reservations on MISO OASIS that utilize the contract path between South and Midwest and are exporting the MISO BA for the applicable Season of the Planning Year. This difference determines the SREC and SRIC to be utilized for that Season of the Planning Year.

Example from the 2016-2017 Planning Year

1. The RDTL from South to Midwest is 2,500 MW and from Midwest to South is 3,000 MW.
2. MISO's feasibility analysis for the 2016-2017 Planning Year determined that no additional reduction of the RDTL was required; 0 MW.
3. The net RDTL for 2016-2017 is equal to the initial RDTL; South to Midwest is 2,500 MW and from Midwest to South is 3,000 MW.

4. The MISO OASIS Reservations, in each direction, that exported from the MISO BA for the 2016-2017 Planning Year were summed:
   South to Midwest Direction: 1,624 MW
   Midwest to South Direction: 206 MW

Final SREC and SRIC applied for the 2016-2017 Planning Year:
South SRRZ SREC: 876 MW
South SRRZ SRIC: 2,794 MW
North SRRZ SREC: 2,794 MW
North SRRZ SRIC: 876 MW

1.1.1.2.5 5.2.1.5.2 Regional Directional Transfer Limit Feasibility Analysis

On an annual basis, prior to administrating the PRA, MISO will review operational data from the previous seasonal peaks to determine if operational events experienced in the past and forecasted expected conditions for the applicable Planning Year Season warrant a reduction in the initial RDTL between the MISO South and Midwest Regions. MISO will review the results of the feasibility analysis with stakeholders prior to implementing in a PRA.

The following data sources are considered for the feasibility analysis:

- Studies that assess MISO transfer capability between Regions
- Studies that assess load diversity between Balancing Authorities
- Transmission system constraints
- Congestion history on relevant transmission constraints
- Capacity or Transmission Emergency alerts, warnings, or events

5.2.2 Local Requirements and Transfer Capability

5.2.2.1 Calculation of Transfer Limits for the Planning Resource Auction(s)

MISO will determine the seasonal import and export limits for each LRZ by performing a transfer analysis study. The study produces Zonal Import Ability (ZIA) and Zonal Export Ability (ZEA) values which represent a zone's ability to import and export capacity in every Season, respectively. The seasonal ZIA and ZEA values are adjusted by the amount of exports (Controllable Exports (CE)) to non-MISO load from the zone to determine a zone's seasonal CIL and CEL. Seasonal CIL and CEL determine the maximum amount of ZRCs that can be imported or exported respectively to/from that zone in that Season. The seasonal ZIA is an input to the calculation of the seasonal Local Clearing Requirement (LCR) for each LRZ, as described in Section 5.2.2.3 (Establishment of Local Clearing Requirement). Seasonal LCR, CEL, and CIL are inputs to the Planning Resource Auction clearing process. Transfer analysis will be performed on seasonal Powerflow models appropriate for the upcoming Seasons in the next planning year.

Transfer analysis is not required to calculate an ERZ CEL; instead, MISO will determine the seasonal CEL of each ERZ by determining the volume of SAC for External Resources within that zone. The seasonal CEL will be set to the MW SAC in the ERZ no later than eight (8) business days before the last business day in March.

Transfer Analysis

Transfer capability is the measure of the ability of interconnected electric systems to reliably transfer power from one area to another under certain system conditions. The incremental amount of power that can be transferred will be determined through First Contingency Incremental Transfer Capability (FCITC) analysis. First Contingency Total Transfer Capability

(FCTTC) indicates the total amount of power able to be transferred before a constraint is identified. FCTTC is the base power transfer plus the incremental transfer capability.

$$Total\ Transfer\ Capability\ (TTC) = Base\ Power\ Transfer + \ FCITC$$

Linear FCITC analysis will identify limiting constraints with a minimum Distribution Factor (DF) cutoff of 3%, meaning the transfer and contingency must increase the loading on the overloaded element by 3% or more. In addition, facilities must have loadings 100% or more of the normal rating for system-intact conditions and loadings 100% or more of the emergency rating for N-1 contingencies.

Export and import capabilities of subsystems will be respected and machine limits are enforced. Exporting an LRZ's available capacity will include offline units. A pro-rata dispatch is used which ensures all available generators will reach their max dispatch level at the same time. The pro-rata dispatch is based on the MW reserve available for each unit and the cumulative MW reserve available in the subsystem. The MW reserve is found by subtracting a unit's base dispatch from its maximum dispatch, which reflects the available capacity of the unit. Refer to Table 2 and the equation below for an example of how one unit's dispatch is set, given all machine data for the source subsystem.

Machine	Base Model Unit Dispatch (MW)	Minimum Unit Dispatch (MW)	Maximum Unit Dispatch (MW)	Reserve MW (Max dispatch – Unit Dispatch)
1	20	20	100	80
2	50	10	150	100
3	20	20	100	80
4	450	0	500	50
5	500	100	500	0
			Total Reserve	310

Table 2: Example Subsystem

$$Machine\ 1\ Post\ Transfer\ Dispatch = \frac{(Machine\ 1\ Reserve\ MW)}{(Source\ Subsystem\ Reserve\ MW} \times Transfer\ Level\ MW$$

$$Machine\ 1\ Post\ Transfer\ Dispatch = \frac{80}{310} \times 100 = 25.8$$

$$Machine\ 1\ Post\ Transfer\ Dispatch = 25.8$$

General Assumptions

Power flow models and input files are required to determine the import and export limits of each LRZ in each Season. Input files (subsystem and contingency) from MTEP studies built for timeframes matching the effective period of the transfer limit study will be used. Single-element contingencies in MISO and seam areas are evaluated. Other than the power flow model, all other input files will be the same across all Seasons within the Planning Year.

Subsystem files will be modified to include required source and sink definitions, details are provided in the next two sections (Import and Export Limit Determination Sections). The monitored file will include all facilities under MISO functional control and Seam facilities 100 kV and above.

Power flow models will contain approved MISO MTEP Appendix A and Target A projects with effective dates on or before the effective date of the study model. Planning Resources, internal and external to MISO will be dispatched in the base model according to the Generator Modeling and Transactions/Interchanges sections of the Transmission Planning Business Practices Manual, or BPM-020. The following generators are excluded from the incremental transfer analysis dispatch:

- Nuclear
- Generators with negative dispatch
- Hydro
- Wind
- Solar

Wind and solar will be ramped down for transfers and will not be ramped up. Maximum wind output will be limited to base dispatch in the power flow model which is set by the wind capacity credit. MISO and external area interchange in the base case will be set to the net of the expected firm transactions with its neighbors.

If a Transmission Owner has identified a zonal import limit that is binding as a result of the exclusion of nuclear (headroom) or other resources in the sink of the transfer study, the TO may inform MISO of the limitation and MISO will evaluate the ZIA and update accordingly, at MISO's sole discretion.

Seasonal Zonal Import Ability (ZIA) and Seasonal Capacity Import Limit (CIL) Determination

To determine an LRZ's seasonal limits, a generation-to-generation transfer is modeled from a source subsystem to a sink subsystem. For import limits, the limit is determined for the sink subsystem. Import limits are found by increasing MISO generation resources in adjacent Local Balancing Authorities (LBAs) while decreasing generation inside the LRZ under study. LBAs that are interconnected with the LRZ under study are considered adjacent. Tiers are used to define the generation pool used for import studies and are comprised of the adjacent systems of the zone being studied.

- Tier 1 – Generation in the MISO LBAs adjacent to the LRZ under study
- Tier 2 – Tier 1 plus generation in MISO LBAs adjacent to Tier 1

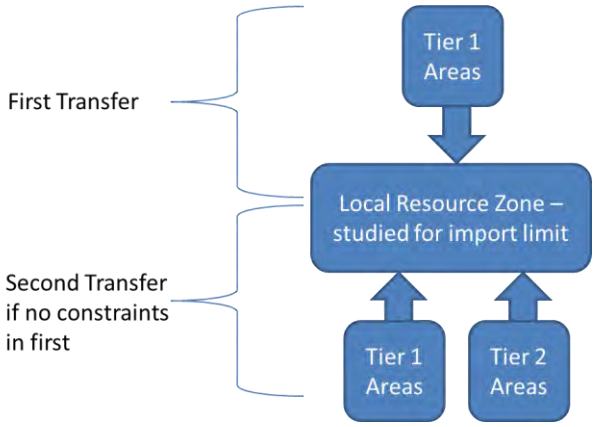


Figure 5.1: Tiered import illustration

Import limit studies are analyzed first using Tier 1 generation only. If no constraint is identified, the source is expanded to include Tier 2 and the transfer is retested. If a constraint is identified, redispatch is tested. If redispatch mitigates the constraint completely and an additional constraint is not identified, the source is expanded to include Tier 2 and the transfer is retested. If constraints are identified using Tier 1 generation, Tier 2 generation is not needed to determine the zone's import limit.

The results of the analysis produce the seasonal Zonal Import Ability. This value will be used to determine the seasonal CIL after accounting for exports to non-MISO load.

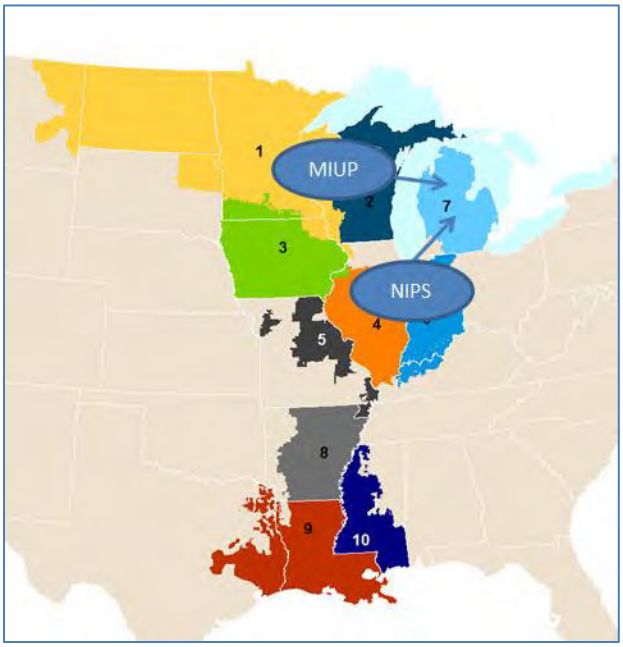


Figure 5.2: Example - MISO LBAs Used for First Test of LRZ 7 import limits

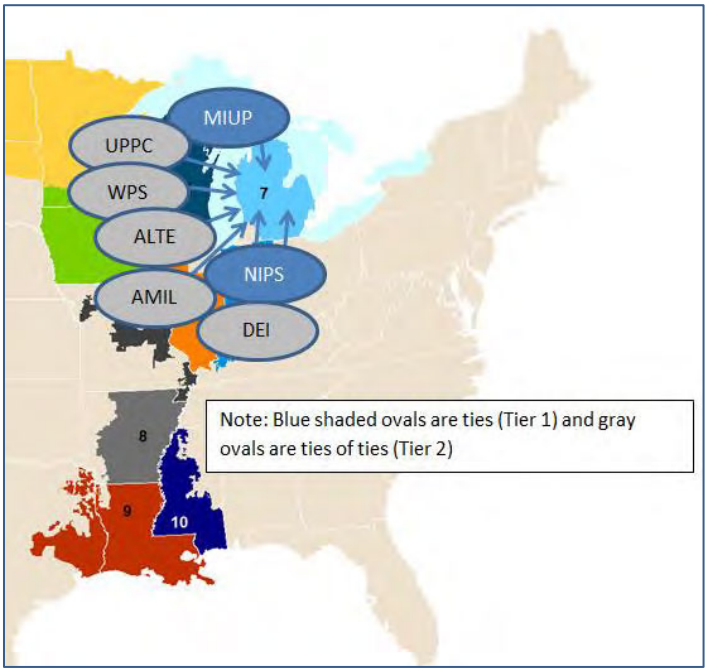


Figure 5.3: Example - MISO LBAs Used for Second Test of LRZ 7 import limits

Seasonal Zonal Export Ability (ZEA) and Seasonal Capacity Export Limit (CEL) Determination

The LRZ being studied for a seasonal export limit, is the source subsystem for the transfer. Available generation within the LBA(s) contained in that particular LRZ is increased proportionately while all generation dispatched, except for nuclear, wind and other intermittent resources, in all other MISO LBAs is decreased proportionately. This method produces the seasonal ZEA which is used to determine the seasonal CEL after accounting for exports to non-MISO load.

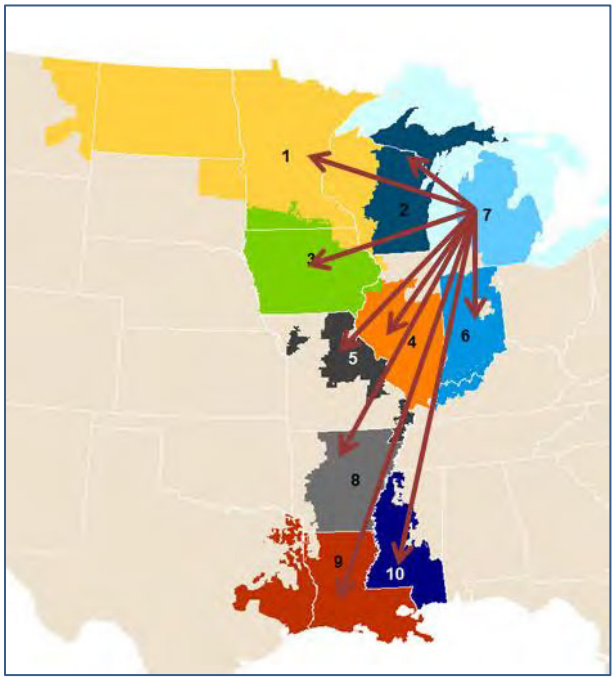


Figure 5.4: Example - MISO LBAs Used for LRZ 7 export limits

Redispatch

LOLE study redispatch is based on prior MTEP study methods. The base assumptions are as follows:

- No more than 10 conventional plants or wind plants will be used
- Redispatch limited to 2,000 MW total (1,000 MW up and 1,000 MW down)
- Nuclear units are excluded
- Wind and other intermittent resources can only be ramped down

For import redispatch scenarios, all generation resources in the zone being studied and adjacent systems (Tier 1 or Tiers 1 & 2) used for the transfer will be eligible to be ramped up. All MISO generation resources will be eligible to be ramped down. If the limiting constraint is a Reciprocal Coordinated Flowgate (RCF), MISO will work with the Seam entity to determine if an adjustment to external dispatch is appropriate and impactful.

For export redispatch scenarios, only MISO generation resources within the zone being studied are eligible to be ramped up. All MISO generation resources are eligible to be ramped down. As with import redispatch, if the limiting constraint is a Reciprocal Coordinated Flowgate (RCF), MISO will work with the Seam entity to determine if an adjustment to external dispatch is appropriate and impactful.

Adjustment for Exports to Non-MISO Load

FERC issued an order on December 31, 2015 which required studies to be neutral to units within MISO areas that are exporting to non-MISO load. MISO identifies and removes the impact of these exporting units on zonal area interchange. These adjustments result in an increase to CIL and decrease to CEL for zones with exports to non-MISO load.

Generation Limited Transfer

When conducting transfer analysis, the source subsystem might run out of generation to dispatch before identifying a constraint caused by a transmission limit. MISO has developed a process referred to as Generation Limited Transfer, or GLT, to identify transmission constraints in these situations.

After running the FCITC analysis to determine import and export limits for each LRZ, MISO will determine whether a zone is experiencing a GLT. If the LRZ is experiencing a GLT, MISO will adjust the base model dependent on whether the analysis is an import or export study and re-run the transfer analysis.

For an export study, when a transmission constraint has not been identified after dispatching all generation within the exporting system (LBAs under study) MISO will decrease load and generation dispatch in the study zone. The objective of the adjustment is to create additional capacity to export from the zone. After the adjustments are complete, MISO will perform transfer analysis on the adjusted model to be in line with section 5.2.2.1 (Calculation of Transfer Limits for the PRA). If a GLT is observed again, further adjustments will be made to the load and generation of the study zone.

For an import study, when a transmission constraint has not been identified after (a) decreasing all generation within the LRZ under study, (b) or dispatching all generation within Tiers 1 & 2, MISO will adjust load and generation in the source subsystem, Tiers 1 & 2. This will increase the capacity available to import into the study zone. After the adjustments are complete, the transfer analysis will be completed on the adjusted model to be in line with section 5.2.2.1. If a

GLT is observed again, further adjustments to the model would be made to the load and generation in Tiers 1 & 2.

FCITC could result in the transmission system supporting large thermal transfers for some zones which might result in some additional considerations. First, large GLT adjustments for export limits could result in reactive-power issues in the zone. Additionally, any load scaling beyond 50% of the zone's load in the base model could result in unrealistic modeling for a summer peak scenario and could lead to unreliable limits and constraints. Therefore, load scaling for both import and export studies will be limited to 50% of the zone's load.

If the GLT does not produce a limit for a zone(s), whether due to a valid constraint not being identified or due to other considerations as listed in the prior paragraph or in the case of a Zone where no valid limit is found in a particular Season, then the seasonal CIL or seasonal CEL will use the following equation where Capacity is the amount available to export or import from Tier 1 & 2 LBA's in the Base Case and where Base Case Flows is the Area Interchange for the study LRZ in the base Powerflow model.

ZIA/ZEA = Capacity + Base Case Flows

MISO shall report that LRZ as having no seasonal CIL/CEL limit and ensure that the transfer amount in the PRA will not bind in the first iteration of the Simultaneous Feasibility Test (SFT).

Voltage Limited Transfer for import studies

Zonal imports may be limited by voltage constraints due to a decrease in the generation dispatch in the zone being studied. Voltage constraints might occur at lower transfer levels than thermal limits that are determined by linear FCITC. As such, LOLE studies may include evaluation of Power-Voltage curves for major disturbances for LRZs with known voltage-based transfer limitations. Known transfer limitations will be identified through existing MISO or member Transmission Owner studies. Additionally, a study could be considered if an LRZ's import reaches a level where the majority of the zone's load would be served using imports from non-zonal resources. MISO will coordinate with stakeholders as these scenarios are encountered.

Processing and Reporting Results

The transfer analysis results for each LRZ consist of a list of constraints and their corresponding FCITC and FCTTC values up to the requested transfer level. The constraint with the smallest

FCTTC will be used to determine each Seasons' ZIA, ZEA, CIL and CEL. The limits are the total transfer capability of the corresponding limiting constraint. Refer to Section 5.2.2.3 Establishment of Local Clearing Requirementregarding how the seasonal ZIA impacts the seasonal Local Clearing Requirement (LCR) calculation. Stakeholder review of the constraints will occur through the LOLE working group.

If a zone's seasonal Local Clearing Requirement (LCR) is greater than the zone's seasonal Initial Planning Reserve Margin Requirement (PRMR) and an existing MTEP project is not expected to increase the seasonal ZIA, MISO will follow the process outlined in section 4.5.1 of the Transmission Planning BPM to identify a project to increase the zone's seasonal CIL.

Timeline and Posting of Results
Posting of power flow models and input files will be completed before analysis begins, if stakeholders have feedback for the models, it should be provided to MISO in a timely manner. The models and associated input files will be made available to the same location where MTEP Powerflow models are shared (https://misoenergy.sharefile.com/).

The outcome of this process will identify a ZIA, ZEA, CEL and CIL for each of the LRZs for each Season within the next Planning Year. MISO will publish the values for each LRZ by November 1 preceding the applicable Planning Year.

5.2.2.2 Establishment of Local Reliability Requirement

Each LRZ's seasonal Local Reliability Requirement (LRR) is the amount of SAC MWs required, located within the specific LRZ, to yield a 0.1-day-per-year LOLE at the load level for the LRZ at the time of the LRZ peak, without assistance from resources outside the respective LRZ (other than Border External Resources and Coordinating Owner External Resources modeled in the zone as described in section 4.2.3.2 (External Resource Qualification Requirements)). The LOLE study process is further described in the annual LOLE Study report posted on MISO's website.

Each Seasons' LRR will be established using the following iterative process:

- Use the LOLE model to determine the resources required in the LRZ to maintain 1 day in 10 years LOLE, representing the LRZ as isolated from the rest of MISO with no transmission ties to the outside world.
- Each LRZ contains the same load and internal resources from the PRM Analysis.

- For each LRZ, the model will initially be run with no adjustments to the capacity. If the LOLE is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year for the LRZ. This is comparable to adding Coincident Peak seasonal Demand. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the LRZ until the LOLE reaches 0.1 day per year for the LRZ.
- After solving for 0.1 day per year on an annual basis, risk-deficient Seasons will have a minimum reliability criteria set to 0.01 LOLE and adjustments to capacity in the model will be made until the LOLE reaches 0.01 day per Season.

The minimum amount of capacity above the zonal seasonal Coincident Peak Demand required to meet the reliability criterion of a 0.1 day per year LOLE value will be utilized to establish the Local Reliability Requirement (LRR) for each Local Resource Zone for each Season within the Planning Year. The LRR study utilizes the Year 2 zonal seasonal Coincident Peak Demand supplied by LSEs in the prior Planning Year PRA cycle. The per-unit LRR values are annually calculated by MISO and reviewed with stakeholders through the Loss of Load Expectation Working Group. The zonal per-unit seasonal LRR values are multiplied by the total zonal seasonal Coincident Peak Demand forecast (which is the sum of all CPD forecasts submitted by LSEs in each LRZ) for the prompt Planning Year PRA(s), inclusive of transmission losses, to calculate each Local Resources Zone's Local Reliability Requirement that will be enforced in each annual and Transitional Planning Resource Auction.

5.2.2.3 Establishment of Local Clearing Requirement

The final steps in calculating an LRZ's seasonal LCR is to account for the external transmission ties and controllable exports to non-MISO systems, by reducing the seasonal LRR by the seasonal ZIA determined in accordance with Section 5.2.2.1 (Calculation of Transfer Limits for the PRA) and by controllable exports. Controllable exports are firm capacity commitments from MISO units to non-MISO load and may be committed and dispatched by MISO during emergencies. All 10 LRZs have LCRs for each season and they must be met by resources internal to the zone, or by Border External Resources. For example, an LSE with Initial PRMR in LRZ 1, must meet that with ZRCs originated in LRZ1 to meet LRZ1's Local Clearing Requirement. ZRCs from other zones can be used to meet the incremental PRMR greater than LCR up to that zone's Initial PRMR subject to CIL/ CEL and SRIC / SREC.

The formula for determining the seasonal LCR is as follows:

$$\text{Seasonal LCR}_{z1} = \text{Seasonal LRR}_{z1} - \text{Seasonal ZIA}_{z1} - \text{controllable exports}_{z1}$$

MISO will publish preliminary seasonal LCR determinations as part of the preliminary PRA data. These values will be updated no later than mid-March with final, updated controllable export values and seasonal ZIAs.

5.3 Pre-PRA arrangement of capacity scheduling

5.3.1 Fixed Resource Adequacy Plan ("FRAP")

The FRAP will identify resources for which an LSE has ownership or contractual rights that will be relied upon to meet the LSE's Planning Reserve Margin Requirement while also conforming to the Local Clearing Requirement ("LCR") in each LRZ where the LSE has a Initial PRMR in each Season within the Planning Year. An LSE must submit its FRAP for applicable Season(s) via the MECT by the 7th business day of March prior to each Planning Year. MISO will review the FRAP and endeavor to notify the LSE of any issues by March 15. LSEs will have until the PRA(s) offer window opens to resolve any issues identified by MISO.

An LSE can designate its seasonal ZRCs in the FRAP up to the LSE's seasonal Initial PRMR. The seasonal ZRCs used in a FRAP will be deducted from the available seasonal ZRC balance of Planning Resources in the MECT. Any portion of an LSE's seasonal Initial PRMR not covered by the FRAP (or met through paying the Capacity Deficiency Charge) will be cleared in the seasonal PRA.

An LSE submitting a FRAP may be subject to a Zonal Deliverability Charge (ZDC). The ZDC is the difference between the seasonal ACP in the LRZ where the LSE has Initial PRMR obligation and the ACP in the LRZ or ERZ where the ZRC associated with the FRAP is physically located multiplied by the volume of the ZRC associated with the FRAP. An LSE can obtain a ZDC Hedge as a hedge against zonal price differences in each Season within the Planning Year.

Seasonal ZRCs and seasonal obligation included in a FRAP will be modeled in the PRA for the applicable Season.

5.3.2 RBDC Opt Out

An LSE may elect to use the RBDC Opt Out for the upcoming and the next two years' PRAs with an obligation (Final PRMR) that is calculated as shown in section 3.1, and with the RBDC Opt Out Adder determined at the first year of RBDC Opt-Out utilizing the following formula:

$$Final\ PRMR_{LSE} = \sum_{LBA}[(CPDf_{LBA} - FRP_{LBA} + FRS_{LBA}) \times (1 + TL_{LBA}\%) \times \left(1 + PRM_{RTO} + Adder_{RBDC\ Opt\ Out}\right)]$$

Where attributes are seasonal for the following:
Final $PRMR_{LRZ}$ = Final Planning Reserve Margin Requirement per LSE
$CPDf_{LBA}$ = Coincident Peak Demand forecast per LBA
FRP_{LBA} = Full Responsibility Purchase per LBA
FRS_{LBA} = Full Responsibility Sale per LBA
$TL_{LBA}\%$ = Transmission Loss Percentage of LBA
PRM_{RTO} = Planning Reserve Margin in Unforced Capacity set by LOLE Studies
$Adder_{RBDC\ Opt\ Out}$= RBDC Opt Out Adder (Defined in Module A 72.0.0)

In MECT, the LSE's choice of RBDC Opt Out is administrated at the granularity of Asset Owners that have load obligations.

5.3.2.1 Establishment of RBDC Opt Out Adder

MISO will use the systemwide and regional RBDCs, and historical market clearing data (e.g., last three Planning Years's market data) to determine the initial RBDC Opt Out Adder that will be applicable to LSEs that elect the RBDC Opt Out starting with Planning Year 2025-2026. MISO will post the determination of the RBDC Opt Out Adder on the MISO website per the timeline defined in Appendix K.

5.3.2.2 Request for RBDC Opt Out and ZRC designation

A Market Participant representing an LSE that plans to use the RBDC Opt Out must submit its initial intent to do so through the MECT. Such request must include the name and contact information of the RERRA(s) (email, phone number), where its load is subject to jurisdiction, and must be submitted no later than January 15 prior to the upcoming Planning Year. Market Participants representing the LSE need to contact MISO if there are complexities regarding the RERRA-LSE relationship (e.g., an LSE is subject to the jurisdiction of multiple RERRAs). MISO will verify the information and notify the RERRA(s) within five (5) business days following deadline of the LSEs initial submission. The RERRA(s) has up to twenty (20) Business Days to notify MISO whether the requested RBDC Opt Out has been authorized, on or before timeline listed in Appendix K.

If the RERRA(s) notifies MISO that the LSE is not authorized to use the RBDC Opt Out in the upcoming PRA, MISO will deny the LSE's initial submission in MECT. If the LSE is subject to the jurisdiction of more than one RERRA, MISO will deny the LSE's initial submission proposing to use the RBDC Opt Out if any one RERRA indicates that the LSE is not authorized to use the RBDC Opt Out. The LSE may withdraw its initial submission even if it receives authorization from RERRA(s). Otherwise, the LSE must submit its final confirmation to use the RBDC Opt Out in the MECT and must demonstrate that the LSE has designated ZRCs for each Season to meet the LSE's Final PRMR, and its share of LCR, by the 7th business day of March prior to each Planning Year. An LSE that elects the RBDC Opt Out may not use any other options to participate in the PRA (e.g., self schedule, FRAP, participating auction) to meet its Final PRMR, but may offer any ZRCs in excess of its Final PRMR into the PRA that is consistent with Section 64.1.1.d of Module D.

MISO will notify the LSE prior to March 15th before the applicable Planning Year whether the ZRCs submitted for the RBDC Opt Out meets the LSE's final PRMR and share of LCR for each LRZ requirement for each Season during the applicable Planning Year. An LSE that does not demonstrate sufficient ZRCs to meet its seasonal Final PRMR and share of LCR on LRZ basis before the PRA offer window opens will be subject to the Capacity Deficiency Charge based on the amount of shortfall in each Season.

An LSE that elects the RBDC Opt Out may be subject to a Zonal Deliverability Charge (ZDC). The ZDC is the difference between the seasonal ACP in the LRZ where the LSE has Final PRMR obligation and the ACP in the LRZ or ERZ where the ZRC associated with RBDC Opt Out is physically located, multiplied by the volume of the ZRC associated with the RBDC Opt Out. An LSE can obtain a ZDC Hedge as a hedge against zonal price differences in each Season within the Planning Year.

Seasonal ZRCs and associated seasonal obligations related to the RBDC Opt Out will be modeled in the PRA for the applicable Season.

5.3.3 LSE's Local Clearing Requirement for LSE's Using a FRAP or RBDC Opt-Out

LSEs that choose to use a FRAP or RBDC Opt Out must designate a sufficient volume of Planning Resources located in the same LRZ to meet the LRZ's LCR requirement in each Season individually. The amount of resources that must be sourced from within the LRZ to satisfy the LSE's seasonal LCR share is equal to the load ratio share of the LSE multiplied by

the total seasonal LCR for its LRZ. The following formula is used to determine each LSE's FRAP or RBDC Opt Out LCR requirements for each Season.

$$LSE\ LCR = \left[\frac{LSE\ PRMR'}{Zonal\ PRMR'}\right] * Zonal\ LCR$$

$$Minimum\ LSE\ \ ZONE\ = \max\left(0, \left[\frac{LSE\ LCR * LSE\ \ NON\ ZONE}{(LSE\ PRMR' - LSE\ LCR)}\right]\right)$$

$$for\ the\ given\ LSE\ \ NON\ ZONE$$

$$Maximum\ LSE\ \ NON\ ZONE\ = \max\left(0, \left[\frac{LSE\ \ ZONE * (LSE\ PRMR'\ -\ LSE\ LCR)}{LSE\ LCR}\right]\right)$$

$$for\ the\ given\ LSE\ \ ZONE$$

Where:

LSE LCR:	Amount of ZRCs that must be supplied from the same LRZ where the LSE's Initial PRMR is located
LSE ZONE:	ZRCs that are in the same LRZ as the Initial PRMR that is being met through a FRAP or RBDC Opt Out by the LSE
LSE NON ZONE:	ZRCs from an ERZ or that are not in the same LRZ as the Initial PRMR that is being met through a FRAP or RBDC Opt Out by the LSE
LSE PRMR':	Total Initial PRMR the LSE has in the LRZ
ZONAL PRMR':	Total Initial PRMR for all LSEs in the LRZ
Zonal LCR:	The minimum amount of ZRCs that are located within an LRZ that is required to meet the LOLE while fully using the Capacity Import Limit for such LRZ.

EXAMPLE :

All LSE Initial PRMR in following example is calculated based on the MISO-established PRM, even if the LSE is subject to the jurisdiction of a state that has established its own PRM

LSE Initial PRMR = 100 MW in LRZ 1
LSE LCR = 80 MW in LRZ 1

To apply ZRCs from other LRZs or an ERZ in the FRAP (or RBDC Opt Out), the following condition must be satisfied when the LSE LCR≤ LSE Initial PRMR:

$$\left[\frac{(LSE\ ZONE + LSE\ NON\ ZONE)}{LSE\ PRMR}\right] \leq \left[\frac{LSE\ ZONE}{LSE\ LCR}\right]$$

When the LSE LCR>LSE Initial PRMR, the LSE should only use ZRCs inside the resource zone to meet its Initial PRMR:

$$LSE\ NON\ ZONE = 0$$

Substituting the value for *LSE LCR* from above, the above formula can be rearranged and rewritten as:

$$\min(1, \left[\frac{Zonal\ LCR}{Zonal\ PRMR}\right]) \leq \left[\frac{LSE\ ZONE}{(LSE\ ZONE + LSE\ NON\ ZONE)}\right]$$

Where *LSE Total* is simply the sum of the FRAP from within and outside of the zone. To state more simply, an LSE must maintain a balance of FRAP (or RBDC Opt Out) in zone to total FRAP (Or RBDC Opt Out) greater than or equal to the ratio of the zone's LCR and Initial PRMR.

Case 1: LSE ZONE = 40MW in LRZ 1
LSE NON ZONE = 10 MW from LRZ 2

$$\left[\frac{(40+10)}{100}\right] \leq \left[\frac{40}{80}\right] \Rightarrow \left[\frac{1}{2}\right] \leq \left[\frac{1}{2}\right] \Rightarrow Pass: 10\ MW\ of\ ZRCs\ from\ other\ LRZ\ is\ allowed\ for\ the\ given\ LSE\ \ NON\ ZONE\ of\ 10\ MW,$$

$$Minimum\ LSE\ \ ZONE\ = \left[\frac{80 * 10}{(100-80)}\right] = 40\ MW$$

NOTE: 40 MW represents the minimum amount of FRAP (or RBDC Opt Out) that must be fulfilled by the ZRCs in LRZ 1 in this case.

Case 2: LSE ZONE = 60 MW
LSE NON ZONE = 20 MW

$$\left[\frac{(60+20)}{100}\right] \leq \left[\frac{60}{80}\right] \Rightarrow \left[\frac{4}{5}\right] \leq \left[\frac{3}{2}\right] \Rightarrow Fail: 20\ MW\ of\ ZRCs\ from\ other\ LRZ\ is\ not\ allowed$$

for given LSE ZONE of 40 MW,

$$Maximum\ LSE\ \ NON\ ZONE\ = \left[\frac{60 * (100 - 80)}{80}\right] = 15\ MW$$

NOTE: 15 MW represents the maximum amount of ZRCs from other zones which can be used to FRAP or RBDC Opt Out LSE's Initial PRMR in LRZ 1 in this case.

5.4 Hedges and Zonal Deliverability Benefit

5.4.1 Zonal Deliverability Benefit

Price separation between Local Resource Zones (LRZs), External Resource Zones (ERZs), or groupings of LRZs, including Sub-Regional Resource Zone (SRRZs) occurs due to constraints binding in the Planning Resource Auction(s) (PRA). Zonal Resource Credits (ZRC) will receive the Auction Clearing Price (ACP) based upon the LRZ or ERZ where the Planning Resource underlying the ZRC is physically located for each Season within the Planning Year.

As a result of price separation, the Transmission Provider may collect more debits from LSEs than it credits the owners of the seasonal ZRCs. Excess amounts will be distributed as follows:

1. Historical Unit Considerations (HUCs) and Zonal Deliverability Charge (ZDC) Hedges owed payment.
2. Any remaining excess revenue shall be distributed on a *pro rata* basis to Deliverability Benefit Zones (DBZs). A DBZ is a group of one or more LRZs with equal ACPs driven by the same auction constraint.

5.4.1.1 Zonal Deliverability Benefit Pro Rata Allocation Methodology

The *pro rata* distribution is applied to each applicable Season and is based upon the LSE's eligible Adjusted Final PRMR. . Adjusted Final PRMR is the Final PRMR minus HUCs and ZDC Hedges.

MPs with Fixed Resource Adequacy Plans or RBDC Opt Out are eligible to receive ZDB.

The *pro rata* methodology to allocate ZDB uses a weighted average approach to calculate the benefit, in dollars, to importing DBZs of all exports within MISO – a weighted average exporting ACP. This weighted average pool of dollars is then allocated to importing DBZs within MISO on a *pro rata* methodology based upon the difference between the importing DBZ ACP and the

weighted average exporting ACP and the MW amount of imports into a DBZ. The ACP for each LRZ within an importing DBZ is adjusted by dividing the benefit dollars allocated to the DBZ by the total PRMR of all LRZs within a specific DBZ. The specific steps to allocate ZDB are described below.

1. Subtract Final PRMR and ZRCs associated with HUCs and ZDB Hedges to derive an adjusted Final PRMR (Adjusted Final PRMR) and ZRC (Adjusted ZRC).
2. Create a DBZ for each group of LRZs that have equal ACPs which result from the same auction constraint.
3. For each DBZ, subtract the sum of Adjusted Final PRMR for each LRZ within the DBZ from the sum of Adjusted ZRCs for each LRZ within the DBZ. A DBZ will be considered a net importing DBZ if the sum of Adjusted Final PRMR is greater than the sum of Adjusted ZRCs. A DBZ will be considered a net exporting DBZ if the sum of the Adjusted Final PRMR is less than the sum of Adjusted ZRCs. A net exporting DBZ shall not receive any ZDB credit. A net importing DBZ shall receive a ZDB credit allocation based upon this weighted average approach.
4. Calculate the weighted average ACP of all net exporting DBZs (Weighted Average Export ACP) to determine a financial value of export capacity within the Transmission Provider region per the formula below:

$$\text{Weighted Average Export ACP} = \frac{\sum(\text{Net Export}_j \times \text{ACP}_j)}{\sum \text{Net Export}_j}$$

Where j = Each net exporting DBZ

5. Calculate the ZDB credit allocation, in dollars, for each net importing DBZ:

$$\text{ZDB Credit}_k = \text{Net Import}_k \times (\text{ACP}_k - \text{Weighted Average Export ACP})$$

Where k = Each net importing DBZs

6. Distribute the ZDB credit in each DBZk by dividing the ZDB credit by the sum of Adjusted Final PRMR of the LRZs within each DBZk. Subtract this amount from the initial ACP calculated for each LRZ from the PRA.

FRAP or RBDC Opt Out Contribution to ZDB

Furthermore, ZDB includes credits collected from FRAPs or RBDC Opt Out that contain ZRCs located in LRZs that have a greater ACP than the respective PRMR's LRZ. This ZDB will be allocated on a *pro rata* basis by Adjusted Final PRMR to all LSEs within the DBZ where the ZRC associated with the FRAP or RBDC Opt Out is physically located.

Allocation of Zonal Deliverability Charge ("ZDC")

A FRAP will be subject to a ZDC if the ACP of the LRZ where the ZRC is physically located is less than the ACP of the LRZ where the Final PRMR associated with the FRAP or RBDC Opt Out is physically located. ZDC collected by the Transmission Provider that is not associated with a ZDC Hedge will be allocated on a *pro rata* basis by Adjusted Final PRMR to all LSEs within the DBZ where the Final PRMR associated with the FRAP or RBDC Opt Out is physically located.

A detailed example of ZDB *pro rata* allocation methodology is in Appendix P.

5.4.2 Historical Unit Considerations (HUCs)

A HUC is a financial hedge against ACP differentials between LRZs or between an LRZ and an ERZ. HUCs for existing capacity agreements hold LSEs harmless from price separation to the extent that excess auction funds are sufficient. HUCs for existing LSEs will be eligible until the end of the original term of the arrangement, not including any evergreen extensions, or for two years – whichever is longer.

The following criteria must be satisfied for HUC approval:

- LSE must have ownership or contractual rights to the resource
- Must have resource and load located in two different LRZs or a resource located in an ERZ
- Must have either NRIS or firm transmission service from the resource LRZ to the load LRZ
- Contracts and its associated NRIS or firm transmission service must be valid through the entire Planning Year
- Contracts must be a) Grandfathered Agreements, b) arrangements executed and in place on or before July 20, 2011, or c) arrangements that predate March 26, 2018 and pertain to External Resource represented in External Resource Zones
- For both new and existing LSEs, HUCs will expire at the end of the contract term, unit ownership change or unit retirement date, whichever is sooner. Contracts expiring during the upcoming Planning Year are not eligible for a HUC covering the planning year. Contracts that have been renewed by evergreen contract provisions are only valid for two Planning Years from the date of the HUC registration

- A HUC must be registered in the MECT by November 1 prior to each Planning Year[2]. HUC Registrations will need to have all information populated except for the Planning Resource, Asset Owner, Resource Zone and TSR and/or NITS identification number(s). Once the SAC MW for Planning Resources is published, MISO will allow Market Participants to update the Planning Resource, Asset Owner, Resource Zone, and TSR and/or NITS ID number information only. Updates will need to be completed by February 1 prior to the Planning Year
- A separate HUC registration is required for each Planning Resource and load within each LRZ or a resource located in an ERZ
    - One Planning Resource in a registration can only select one LRZ or ERZ
- The MW in HUC registrations that are paid will not exceed the LSE's seasonal Final PRMR minus their LCR.
- If there are more HUCs than a DBZ's Final PRMR minus its LCR, then HUC payments will be pro-rated by multiplying the difference between Final PRMR and LCR divided by the total HUCs.
- If Market Participants enter a seasonal ZRC transaction to fulfill contracts that meet the criteria for a hedge, MISO must be able to determine the source of the ZRCs in order to apply the HUC financial hedge to the auction results
    - ZRCs transacted to fulfill existing contracts will need to have specific unit identifiers from aggregate deliverable generators
- Based on the ZRCs transacted, MISO will work with the MP that qualified the HUC to determine in which LRZ or ERZ the Planning Resource is located

If a Load is in an LRZ with a higher ACP than the LRZ or ERZ where the Resource is located, the MP serving the Load will pay an amount equal to the difference of the ACPs between the LRZ and the LRZ or ERZ where the Resource is located, multiplied by the amount of the unhedged load if a HUC Hedge does not exist. This distribution will be limited by the excess auction revenue collected in a given PRA.

A combination of capacity agreements that require the delivery of capacity throughout the Planning Year will qualify for treatment as HUCs, provided that the agreements otherwise satisfy the criteria.

[2]

Facilities under construction on or before July 20, 2011 that subsequently become Planning Resources will be eligible for the HUC Hedge provided that the HUC criteria is satisfied.

Firm resources that meet HUC Hedge criteria may be included as part of a FRAP or RBDC Opt Out or offered into the annual auction. Any MWs of ZRCs in a FRAP or RBDC Opt Out that are qualified under a HUC will not be subject to a Zonal Deliverability Charge assessment and will not receive a HUC payment

5.4.3 Zonal Deliverability Charge Hedge

LSE can obtain a ZDC Hedge as described herein as a financial protection from zonal price differences. Market Participants will be eligible for a hedge against congestion in the auction if the LSE invests in new or upgraded transmission to serve the LSE's load if located in a different LRZ. Network upgrades made for interconnection service (NRIS/ERIS) do not qualify for a ZDC Hedge. Also, any cost shared upgrades would not be eligible for a ZDC Hedge. The participant that funds the upgrades and submits the transmission service request is the participant who is eligible for the ZDC Hedge. However, Network upgrades associated with a Transmission Service Reservation (TSR) from the new resource to load located in a different LRZ would qualify. The volume of a ZDC Hedge will be the incremental increase in the CIL that resulted from the Network Upgrades identified in the approved firm transmission service request. Market Participants must register the ZDC Hedge and provide supporting documentation in the MECT by November 1 prior to the Planning Year to demonstrate eligibility. ZDC Hedges will be granted only to LSEs that have Planning Resources that cleared in a PRA.

5.5 Planning Resource Auction (PRA)

5.5.1 Timing of Auctions

Seasonal Planning Resource Auctions will be conducted in the first 20 business days of April, with results posted near the end of April which is approximately one month before the beginning of the first Season of the associated Planning Year (PY). All four seasonal (Summer, Fall, Winter and Spring) PRA's will be conducted in April prior to the PY.

5.5.2 Amount of Capacity Cleared in Each Auction

The seasonal PRA(s) and Transitional PRA shall clear seasonal ZRC offers in order to satisfy 100% of the seasonal Final PRMR for each LSE, less the amount of seasonal Initial PRMR associated with the Capacity Deficiency Charge and inclusive of any resources used in a seasonal FRAP or RBDC Opt Out, in each LRZ. For a Season, if the total volume of seasonal

ZRC offers is less than total seasonal Final PRMR, MISO will clear the total volume of offered ZRCs for that Season respecting established CIL, CEL, SRIC and SREC.
For LSEs not selecting the RBDC Opt Out, the Final PRMR is established as a result of the PRA clearing using RBDCs. For LSEs selecting the RBDC Opt Out, Final PRMR is the same as Initial PRMR, which is based on the sum of the applicable PRM plus the applicable RBDC Opt Out Adder, as demonstrated in section 3.1. LSEs under state jurisdiction where the state has elected to establish its own planning reserve margin will have a Final PRMR based on the planning reserve margin established by the state.

5.5.3 Conduct of the PRA

The seasonal Planning Resource Auctions shall be sealed bid auctions, which will determine the seasonal Auction Clearing Prices (ACP) for each Local Resource Zone (LRZ) and External Resource Zone (ERZ) modeled in that auction. The auction shall determine the outcome of all seasonal ZRC offers accepted during the qualification process and submitted during the auction offer window.

Step 1: Compilation of Offers
Offers for each of the seasonal auctions must be submitted in the MECT's Submit Offer screen for each specific seasonal auction during the auction offer window period. The offer window for the auction will be opened during the last four business days in the month of March prior to the start of the new Planning Year. Owners of jointly owned facilities can individually offer their share of any such resources into the seasonal PRAs, either as self-schedule price takers or with specific offers or use their share of such resources as part of a seasonal FRAP or RBDC Opt Out.

MISO shall compile all of the offers for each Season, as follows: The MP acting on behalf of any Planning Resource accepted in the qualification process for participation in the auction may submit an offer consisting of price and quantity pairs, indicating the minimum acceptable price and the associated quantity of seasonal ZRCs that the MP would commit to provide from the Resource in the associated modeled LRZ and/or ERZ during the Season within the Planning Year. An offer shall be defined by the submission of up to five price and quantity pairs, each having a strictly greater price than the previous price in the submission. Each price shall be expressed in dollars per megawatt-day, and each quantity shall be expressed in 0.1 MWs. The MW/Price pairs must be monotonically increasing for each price. Each segment of each offer is separately evaluated.

Step 2: Determination of the Outcome

MISO shall use the seasonal ZRC offers to determine the aggregate supply curves for each MISO modeled LRZ and/or ERZ. MISO will use the seasonal offers in conjunction with the seasonal import and export constraints, seasonal local clearing requirements, and other inputs to determine the least cost set of offers that respects the various constraints expressed as described in the Tariff. The Transmission Provider will clear offers based on the needs of the LRZ and not the size of a Resource (i.e., if an LRZ needs 50 MW, but a Market Participant has a 100 MW Resource; only 50 MW will clear). At any non-zero clearing price, a pro-rated clearing from tied bids will be applied in conjunction with need, location of resources subjected to tied bids, and import and export limits of respective LRZs. At a zero-clearing price, all zero-price and price-taking offers will be accepted.

Inadequate Supply

While the auction process will endeavor to select seasonal ZRC offers sufficient to meet the seasonal requirements of each LRZ, it is possible that sufficient resources are not available in the LRZ and the LRZ would thus be short of Planning Resources for that Season within the Planning Year. In such cases, the auction will clear all seasonal ZRC offers in the LRZ for that Season and, if the LRZ is short ZRC's to meet the seasonal requirements, the entire LRZ will clear at the LRZ's seasonal CONE value. If the LRZ is short of ZRC's to meet the requirements for more than one Season within the Planning Year, then the ACP for such Seasons will be determined as described in section 69A.7.1 of Tariff Module E-1.

5.5.4 Market Monitoring

All participation by Market Participants is subject to the market power mitigation rules regarding physical and economic withholding of capacity as described in Module D of MISO's Open Access Transmission Tariff and Market Monitoring BPM-009. All Planning Resources except for External Resources, Load Modifying Resources, and Energy Efficiency Resources are subject to physical and economic withholding monitoring. Below are additional details regarding the application of these market monitoring provisions. In addition to these details, please refer to Module D and BPM-009 Market Monitoring and Mitigation for additional details.

5.5.4.1 Physical Withholding

Sec. 64.1.1.d of Module D describes the Physical Withholding Provisions in the PRA. The IMM has established a Physical Withholding Threshold Limit of 50 MW per LRZ that is applied as a sum to a Market Participant (MP) and its Affiliates. Thus, there is a total of 50 MW of deliverable

SAC (ZRCs) whose rights are owned by an MP and its Affiliates in each LRZ that are not required to submit an offer into the PRA or be part of a FRAP or RBDC Opt Out. If the sum of deliverable SAC MW withheld exceeds the Physical Withholding Threshold Limit, the MP and its Affiliates would fail for conduct (Conduct Test) for physical withholding and be subject to the Impact Test described in Module D.

5.5.4.2 Economic Withholding

Sec. 64.1.2.d of Module D describes the Economic Withholding Provisions in the PRA. By default, each Planning Resource subject to economic withholding has an initial Reference Level for their PRA offer of $0/MW-Day. A Conduct Threshold equal to 10% of the LRZ Daily CONE (Daily CONE = LRZ CONE / 365) is allowed for a PRA offer without failing conduct (Conduct Test) for economic withholding and be subject to the Impact Test described in Module D.

An MP may submit a request for a Facility Specific Reference Level (FSRL) to the IMM. The request must be accompanied by evidence and documentation of Going Forward Costs (operating and capital) to operate the Planning Resource for the next Planning Year. Going Forward Costs must be sufficient detail to specify costs specific to suspension or retirement. Refer to BPM-009 Market Monitoring and Mitigation for additional details.

Market Participants have the option to use Default Technology Specific Avoidable Costs (DTSAC) calculated by the IMM as specified in Module D for operating cost recovery in lieu of submitting their own documentation for operating costs. The DTSAC values in Module D are broken down by different generator classifications for suspension and retirement requests. Refer to BPM-009 Market Monitoring and Mitigation for additional details.

5.5.5 Target Reliability Value

The resultant target reliability value for each Season for each LRZ will be the greater of the system-wide seasonal Planning Reserve Margin Requirement based on MISO's seasonal PRM or the seasonal LCR value. The sum of these seasonal LRZ target reliability values will be the system's target seasonal reliability value, that is, the amount of SAC MW that must be obtained, if available, from the auction.

5.5.6 Resource Offers

Any seasonal ZRCs that were not used in a FRAP or RBDC Opt Out can be offered into the seasonal PRA during the auction window period. The following business rules are applied to the seasonal ZRC offers for the seasonal PRA:

- Offer cannot be changed or withdrawn after the auction window is closed.
- Smallest Offer MW = 0.1 MW.
- Offer Segment defined as a price-quantity pair.
- Up to 5 Offer Segments per Planning Resource.
- Lowest Offer price is $0.00/MW-Day.
- Highest Offer Price for each Season and zones (LRZ and ERZ) is the annual LRZ/ERZ CONE divided by the total number of days in the Season.
- The Transmission Provider will clear offers based on the needs of the LRZ and not the size of a Resource (i.e., LRZ needs 50 MW, but Market Participant has a 100 MW Resource; only 50 MW will clear). At a zero-clearing price, all zero-price and price-taking offers will be accepted.

Self-Scheduling

LSEs that "self-schedule" ZRCs by submitting offers into the PRA(s) with a price of $0.00 will always clear the auction.

Sub-Regional Constraints

The Sub Regional Import Constraint (SRIC) and the Sub Regional Export Constraint (SREC) for each Sub Regional Resource Zone (SRRZ) are the transmission constraint parameters which must be respected, in addition to CILs and CELs for each LRZ, when conducting the PRA or in the Resource Replacement process. A SRRZ consists of more than one LRZ. The North/Central SRRZ consists of LRZs 1-7, and the South SRRZ consists of LRZ 8-10.

The Transmission Provider will establish and publish, on the Transmission Provider's public website, SRRZs, seasonal SRECs and seasonal SRICs as soon as practical but no later than the first business day of March for the following Planning Year.

5.5.7 Seasonal Simultaneous Feasibility Test (SFT)

Background

The test identifies transmission constraints resulting from power transfers between LRZs and imports to the MISO system from ERZs. To the extent transmission constraints cannot otherwise be mitigated via redispatch of seasonal Planning Resources while holding LRZ imports and exports constant, new seasonal CIL and CEL values (as applicable) are established. Resulting transfers in the auction will be simultaneously reliable and feasible. The seasonal SFT is completed after the seasonal auction clears and is driven by section 69A.7.1 of Tariff Module E-1.

Base Model

Base modeling represents the transmission topology and associated transmission ratings, Demand, and anticipated net interchange for the associated Season: summer, fall, winter, and spring. This is accomplished by the following modeling assumptions:

- Base model
  - Latest available MISO model with expected generation and transmission topology for the effective date of each Season within the Planning Year
- Transmission Topology
  - Includes Appendix A and other Model On Demand projects in-service by the effective date of the specific Season within the Planning Year
- Load
  - Final PRMR cleared through seasonal auction
  - LMRs are modeled as reduction of seasonal Final PRMR where LMRs are physically located
- Dispatch
  - Seasonal FRAP
  - Seasonal RBDC Opt Out
  - Seasonal ZRC offers cleared through the auction
- External representation
  - Latest Eastern Interconnection Reliability Assessment Group Multiregional Modeling Working Group series model matching Planning Year timeframe for each Season where applicable within the Planning Year

The latest seasonal models from the annual MISO series model build provides the best representation of the system and is a better representation than the one-year-old LOLE model used to establish the seasonal CIL and CEL limits. The latest model contains up-to-date topology and has gone through more recent stakeholder review.

Interchange Detail

External units that clear the auction are accounted for by Balancing Authority Area and then the interchange between MISO and the Balancing Authority Areas with cleared units is adjusted to represent the cleared amount. Units within MISO with an external capacity commitment will be dispatched to external load. Interchange will be adjusted to reflect the transaction.

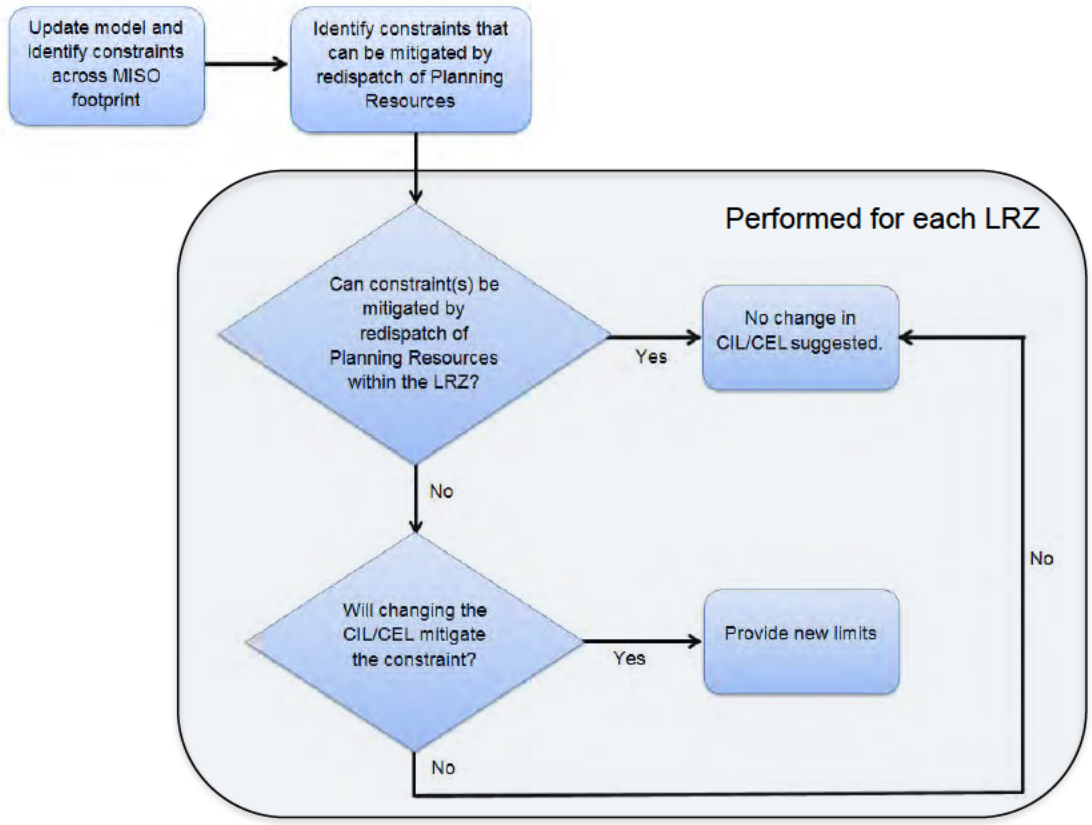
Topology Validation

Model checks are performed prior to the SFTs and PRAs. First, the ratings of facilities found to be limiting in the LOLE study are checked for rating changes. If the facility ratings are updated, the impact on seasonal CEL, CIL and/or ZIA must be determined and included as inputs to the PRAs. Transmission projects included in the LOLE models that were supposed to be in service by the effective date of the model, are validated and updated accordingly if a project's in-service date changes.

Power flow Analysis

The only controllable elements of the auction are the seasonal CIL and CEL. The seasonal SFT determines if any changes to CIL and CEL are required. The initial limits are determined in the annual LOLE study where seasonal CIL and CEL limits are established. These limits are an input to the initial auction clearing process. The SFT process is outlined in Figure 5.5 below.

Figure 5.5: SFT Process Flow



Seasonal CIL and CEL may be modified when the dispatch of Planning Resources within that Season outside the LRZ is the only action to mitigate constraints. To determine if changes are required, it must first be determined if the LRZ is an exporter or importer from the auction results of that Season. If the LRZ is an exporter within the seasonal CEL bounds, no change to limits should cause the LRZ to export more. Similarly, no change to limits should cause an importing LRZ to import more. The changes to limits that are impactful for exporters and importers are outlined as:

- Potential change if Planning Resources outside an LRZ is the only mitigation identified
- Decrease export or import limit if Planning Resources outside LRZ can be ramped up or down respectively to mitigate the constraint
- Decrease limit by MW amount needed to mitigate constraint

The Tariff allows for up to three iterations of the auction clearing process. The first iteration uses the seasonal CIL and CEL values from the LOLE study while the second and third iteration use any updated CIL and CEL values as determined by the seasonal SFT. The second and third iterations are performed only if needed. The clearing iterations are outlined as:

1st Pass

- Inputs to the auction clearing process are seasonal CILs and CELs from LOLE study, seasonal LCR, seasonal SRECs, and seasonal SRICs as applicable
- If all LRZs pass the SFT in that Season, auction results are final and the 2nd and 3rd iteration of auction clearing is not required.

2nd Pass

- Inputs to the auction clearing process are updated. Seasonal CILs and CELs from the 1st Pass and
- If all LRZs pass the SFT, results are final.

3rd Pass

- Inputs to the seasonal auction clearing process are updated. Seasonal CILs and CELs from the 2nd Pass if all zones pass the SFT, results are final. If at least one LRZ does not pass the SFT, the iteration with the fewest MWs of network violations will be deemed as the final auction result.

5.5.8 Auction Results Posting

MISO will post the summary of the Planning Resource Auction results on its website twenty (20) Business Days after the auction offer window is closed. The summary includes the following information for MISO system wide and each LRZ for each Season within the Planning Year: Final PRMR, Total Offer + FRAP+RBDC Opt Out, Offer Cleared + FRAP+RBDC Opt Out, LCR, Import Limit (CIL), Export Limit (CEL), Import/Export amount, ACP, deficient amount, and Total Offer Cleared volume for the system.

One month following the completion of any PRA, MISO will post the ZRC Offers in price/quantity pairs on its website without revealing the names of the Market Participants submitting such offers and the names of the Planning Resources offered.

Resource Adequacy Settlement

Transmission Provider will settle each PRA using the following steps:

1. Determine the ACP for ZRCs within each LRZ for every Season.
2. Determine each LSE's Final PRMR. For details see 5.6.

3. Provide HUC credits equal to the zonal ACP differential to Load subject to HUCs in every Season in the Planning Year.
4. Provide ZDC Hedge credits equal to the zonal Auction Clearing Price differential to ZDC Hedge Load amounts in every Season in the Planning Year.
5. Provide ZDB credits to all remaining Final PRMR in the LRZ. The ZDB is a credit against the ACP paid by LSEs with Final PRMR in each LRZ in every Season in the Planning Year.

Settlement calculations for each Season in the PRA will be conducted on a daily basis and the results will be shown under the Real Time Settlements statement. Please refer to the Market Settlements BPM for further details. Below are charge types under the PRA(s) Settlement:

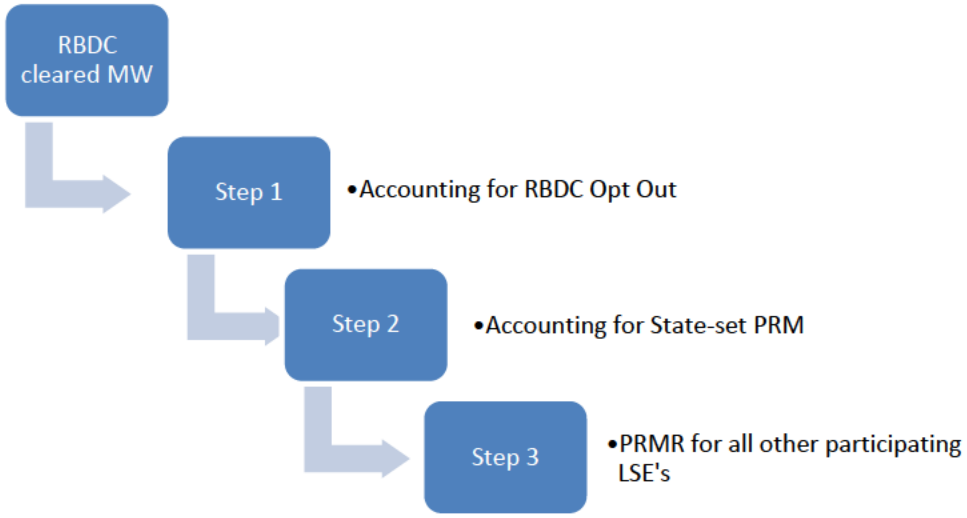
- PRA Charge
- Distribution of PRA Charge
- Zonal Deliverability Charge (ZDC) (*Only applies to the FRAP or RBDC Opt Out)
- Distribution of ZDC
- Capacity Deficiency Charge (Covered outside of the daily settlements)

Cleared seasonal ZRCs from Diversity Contracts that are not self-scheduled or in the LSE's seasonal FRAP or RBDC Opt Out will receive reduced payment based on the total number of days the external resource identified in the Diversity Contract are dedicated to MISO load when an LSE clears more seasonal ZRC in the PRA than its seasonal Final PRMR. The LSEs that converted SAC MW to seasonal ZRCs will receive the seasonal auction clearing price for the entire Season for those seasonal ZRCs that cleared in the seasonal PRA.

5.6 Final PRMR Allocation Process

The Final PRMR of an LSE is determined based on RBDC clearing and the LSE's participation option (such as RBDC Opt Out, market participation, etc.) in the PRA. The RBDC cleared MWs determined during the PRA clearing process will be allocated to determine LSE's Final PRMR using the steps outlined below (Figure 5.6).

Figure 5.6: Overview of Final PRMR allocation process



Step 1: Accounting for RBDC Opt Out

First, determine cumulative MWs corresponding to PRMR obligation of LSEs choosing the RBDC Opt Out option as per Section 5.3.2. Then, deduct this cumulative MWs from the total cleared MW from the PRA clearing. Remaining cleared MWs, if any, are then passed on to step 2.

Step 2: Accounting for State-set PRM

Then, the Final PRMR for LSEs who are under State jurisdiction with the State defined PRM is determined. For such LSEs, their Final PRMR is calculated based on the PRM defined by the respective State. Then, the sum of Final PRMR of LSEs who are under State jurisdiction with the State defined PRM is deducted from the remaining cleared MWs that were calculated in step 1. At the end of step 2, remaining cleared MWs, if any, are determined and then passed on to step 3.

Step3: Determine Final PRMR for other LSEs (Neither RBDC Opt Out nor under State-set PRM)

If the remaining cleared MWs after step 2 of the Final PRMR allocation process are greater than zero, then step 3 of the Final PRMR allocation process will be executed. In this step, remaining cleared MWs, determined in step 2 of the Final PRMR allocation process, will be distributed across remaining LSE's not covered under step 1 or step 2 on a pro-rata basis with respect to their Coincident Peak Load Forecast including transmission losses.

For LSEs participating using FRAP provisions, the quantity that is covered through FRAP provisions will be considered after step 3 of the Final PRMR allocation process. Any additional ZRCs that such LSEs need to procure from the market to meet their share of Final PRMR, will be charged the applicable ACP.

Example 1: RBDC Out Out, No State setting PRM, & Final PRMR higher than Initial PRMR

Consider a system with three LSEs (LSE A, LSE B, and LSE C) and a system peak demand of 100 MW (accounting for the CPD forecast plus transmission losses).

PRA Participation:

- LSE A has a 15MW load and participates in the PRA using RBDC Opt Out provisions.
- LSE B has 50 MW load, and
- LSE C has 35 MW load.

Assumptions:

- No State has defined PRM for its jurisdictional entities
- MISO defined PRM to be 9%
- RBDC Opt Out Adder to be 4%
- Systemwide RBDC clearing in the PRA to be 112 MW (indicating RBDC clearing at 12% above load forecast)
- No SRIC/SREC binding

Final PRMR allocation calculation:

Step 1: Accounting for RBDC Opt Out

In this example, LSE A has 15 MW of load participating in the PRA using RBDC Opt Out provisions. Given a PRM of 9% and an RBDC Opt-Out Adder of 4%, the final PRMR for LSE A will be **16.95 MW**, calculated as 15 * (1 + 9% + 4%). After this allocation, 95.05 MW of cleared RBDC capacity will remain (112 MW - 16.95 MW) for further distribution in the following steps.

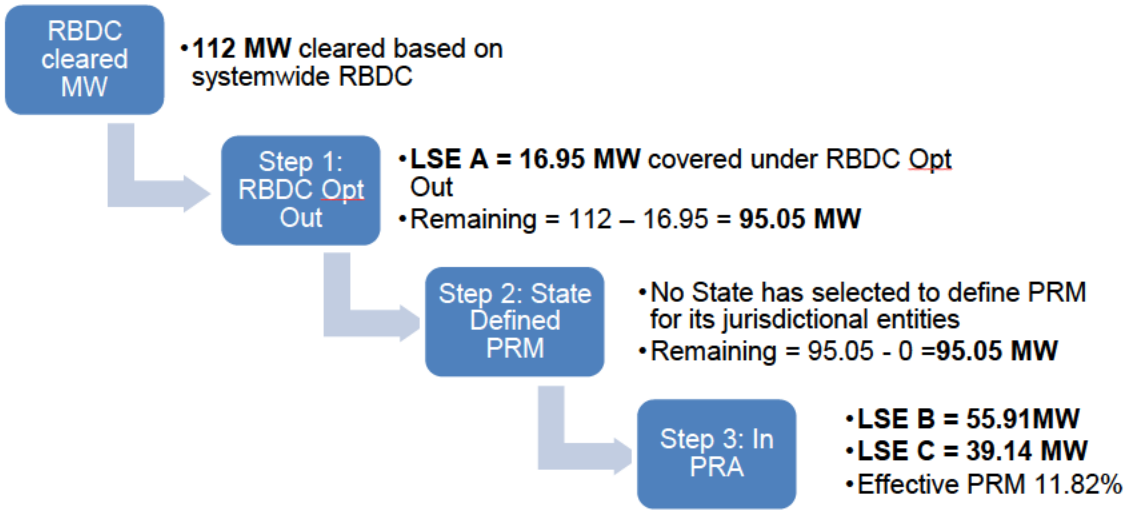
Step 2: Accounting for State-set PRM

In this example, there is no load subjected to State defined PRM. Hence, no Final PRMR is allocated in this step and 95.05 MW of cleared RBDC capacity will still remain (112 MW - 16.95 MW) for further distribution in the following step.

Step 3: Determine Final PRMR for other LSEs (Neither RBDC Opt Out nor under State-set PRM)

In step 3, remaining RBDC cleared 95.05 MW, determined after step 2 of the Final PRMR allocation process, will be distributed across remaining load which is not covered under step 1 or step 2 on a pro-rata basis. In this example, the remaining load after step 1 and step 2 is 85 MW. Hence, the Final PRMR for LSE B will be **55.91 MW**, calculated as 50 * (95.05/85), and the Final PRMR for LSE C will be **39.14 MW**, calculated as 35 * (95.05/85). The effective PRM for load participating in the PRA outside of RBDC Opt Out and State defined PRM is 11.82%.

The example is graphically summarized ahead.



Example 2: RBDC Opt Out, State setting PRM, & Final PRMR higher than Initial PRMR

Consider a system with three LSEs (LSE A, LSE B, and LSE C) and a system peak demand of 100 MW (accounting for the CPD forecast plus transmission losses).

PRA Participation:

- LSE A has a 15 MW load and participates in the PRA using RBDC Opt Out provisions
- LSE B has 50 MW load and subjected to State defined PRM of 10%
- LSE C has 35 MW load

Assumptions:

- MISO defined PRM to be 9%
- RBDC Opt Out Adder to be 4%

- Systemwide RBDC clearing in the PRA to be 112 MW (indicating RBDC clearing at 12% above load forecast)
- No SRIC/SREC binding

Final PRMR allocation:

Step 1: Accounting for RBDC Opt Out

In this example, LSE A has 15 MW of load participating in the PRA using RBDC Opt Out provisions. Given a PRM of 9% and an RBDC Opt-Out Adder of 4%, the final PRMR for LSE A will be **16.95 MW**, calculated as 15 * (1 + 9% + 4%). After this allocation, 95.05 MW of cleared RBDC capacity will remain (112 MW - 16.95 MW) for further distribution in the following steps.

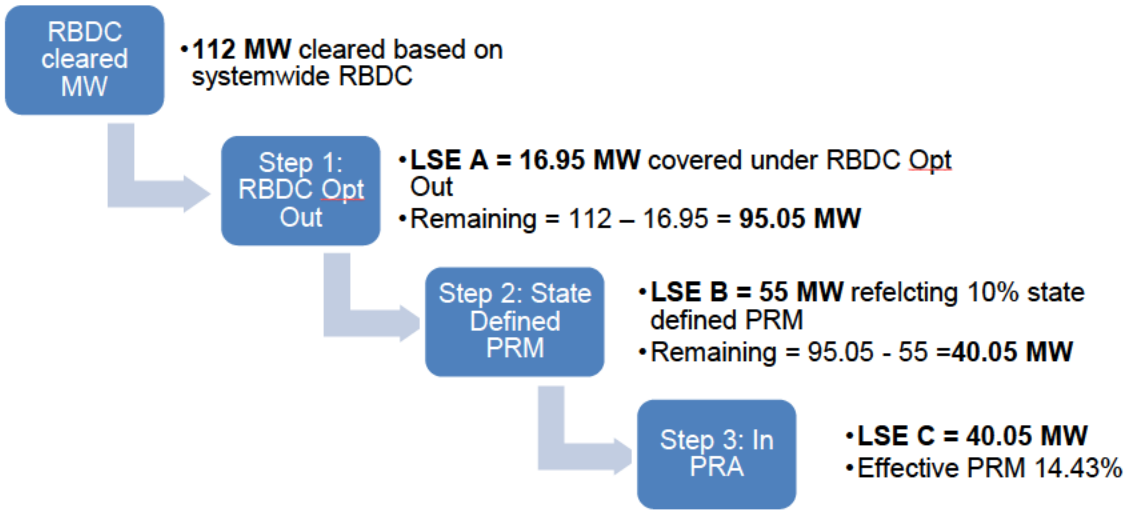
Step 2: Accounting for State-set PRM

In this example, LSE B's load is subjected to State defined PRM of 10%. Hence, the Final PRMR for LSE B is **55 MW**, calculated as 50*(1 + 10%). After this allocation, 40.05 MW of cleared RBDC capacity will remain (95.05 MW – 55 MW) for further distribution in the following step.

Step 3: Determine Final PRMR for other LSEs (Neither RBDC Opt Out nor under State-set PRM)

In step 3, the remaining RBDC cleared 40.05 MW, determined after step 2, will be distributed across remaining load which is not covered under step 1 or step 2 on a pro-rata basis. In this example, the remaining load after step 1 and step 2 is 35 MW. Hence, the Final PRMR for LSE C will be **40.05 MW**, calculated as 35 * (40.05/35). The effective PRM for load participating in the PRA outside of RBDC Opt Out and State defined PRM is 14.43%.

The example is graphically summarized ahead.



Example 3: RBDC Opt Out, State setting PRM, & Final PRMR lower than Initial PRMR

Consider a system with three LSEs (LSE A, LSE B, and LSE C) and a system peak demand of 100 MW (accounting for the CPD forecast plus transmission losses).

PRA Participation:

- LSE A has a 15 MW load and participates in the PRA using RBDC Opt Out provisions.
- LSE B has 50 MW load and subjected to State defined PRM of 10%.
- LSE C has 35 MW load.

Assumptions:

- MISO defined PRM to be 9%
- RBDC Opt Out Adder to be 4%
- Systemwide RBDC clearing in the PRA to be 108 MW (indicating RBDC clearing at 8% above load forecast, lower than PRM)
- No SRIC/SREC binding

Final PRMR allocation:

Step 1: Accounting for RBDC Opt Out

In this example, LSE A has 15 MW of load participating in the PRA using RBDC Opt Out provisions. Given a PRM of 9% and an RBDC Opt-Out Adder of 4%, the final PRMR for LSE A will be **16.95 MW**, calculated as 15 * (1 + 9% + 4%). After this allocation, 91.05 MW of cleared RBDC capacity will remain (108 MW - 16.95 MW) for further distribution in the following steps.

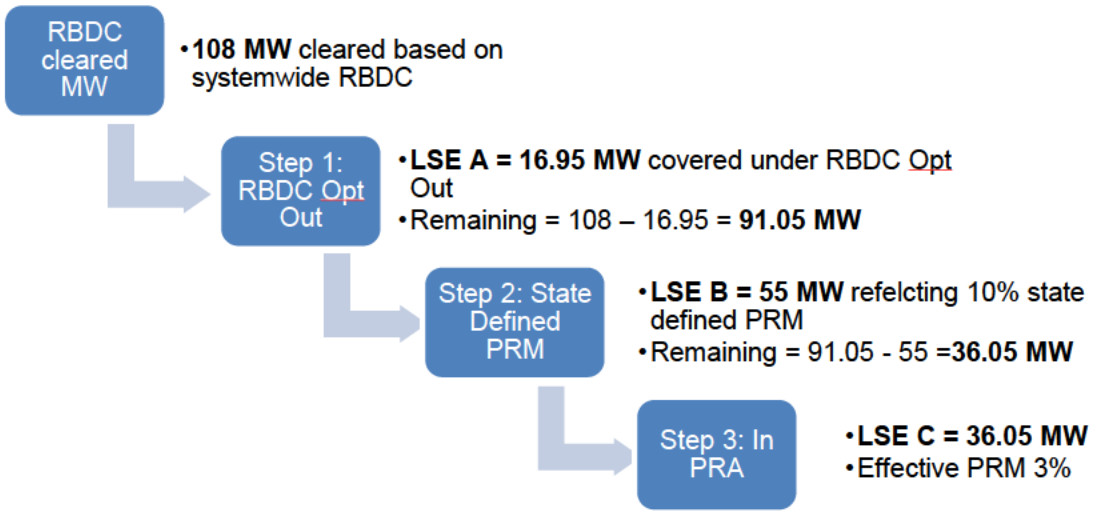
Step 2: Accounting for State-set PRM

In this example, LSE B's load is subjected to State defined PRM of 10%. Hence, the Final PRMR for LSE B is **55 MW**, calculated as 50*(1 + 10%). After this allocation, 36.05 MW of cleared RBDC capacity will remain (91.05 MW – 55 MW) for further distribution in the following step.

Step 3: Determine Final PRMR for other LSEs (Neither RBDC Opt Out nor under State-set PRM)

In step 3, the remaining RBDC cleared 36.05 MW, determined after step 2 of the Final PRMR allocation process, will be distributed across remaining load which is not covered under step 1 or step 2 on a pro-rata basis. In this example, the remaining load after step 1 and step 2 is 35 MW. Hence, the Final PRMR for LSE C will be **36.05 MW**, calculated as 35 * (36.05/35). The effective PRM for load participating in the PRA outside of RBDC Opt Out and State defined PRM is 3%.

The example is graphically summarized ahead.



5.7 Retail and Wholesale Load

Retail and Wholesale Load switching between LSEs can be tracked through the MECT after the start of the in each Season within the new Planning Year. As a result of load switching, the seasonal Final PRMR of the LSEs involved in the load switching will change. Switching of seasonal Retail load will not change an Electric Distribution Company's (EDC) total area

seasonal Final PRMR. Similarly, wholesale seasonal load transaction will not change the total MISO seasonal Final PRMR.

5.7.1 Retail Load Switching

By January 15 11:59 p.m. EST prior to the start of the new Planning Year, retail supplier LSEs will confirm their share (e.g. PLC) of the EDC's area seasonal Initial PRMR. After the Planning Year starts, the Retail LSE's seasonal Final PRMR will change during each Season within the Planning Year when the load from one LSE is switched to another LSE within the EDC area.

Market Participants with Demand in areas subject to retail choice are required to provide the name of the EDC and the CPNode names associated with the LSEs within the EDC area at the time of registration. The CPNode to EDC mapping information is important for determining LSEs' retail load switching method.

EDCs are responsible for updating the seasonal Final PRMR associated with each retail choice LSE in the MECT. The Retail Load screen in the MECT is provided for EDCs in Retail Choice states to track the Retail LSE's day-to-day migration of loads at the Asset Owner (AO) level.

Using the daily retail load switching information in the MECT, MISO Settlements calculates each retail choice LSE's new seasonal Final PRMR. The LSEs' PRMR are subject to resettlement calculations based on the resubmission of load switching information.

The daily retail load switching information includes:

- Name of the EDC
- Name of the LBA
- Operating Date of Retail load switching
- Season (Summer, Fall, Winter or Spring)
- Name of AO(s)
- AO's new Retail MW (with granularity of tenth of a MW)

5.7.2 Wholesale (Non-Retail) Load Switching

A Wholesale Load obligation can be switched from one LSE to another using the Wholesale Load Switching screen in the MECT during each Season of the Planning Year. When Wholesale Load switching occurs, the daily capacity charges of the Wholesale Load will be transferred from the current LSE to the new LSE. The seasonal Final PRMR for affected LSEs will be

decreased or increased, as appropriate, by the amount of the wholesale load plus the seasonal PRM. Procedures for billing, settlement, and credit requirements will be as specified in the appropriate BPMs. LSEs with wholesale contracts that change during the Season within the Planning Year may enter a Wholesale Load switching contract representing seasonal Final PRMR in the MECT.

For the case of Wholesale Load switching, the amount of the seasonal Final PRMR transferred via the wholesale load transaction process will transfer the Final PRMR of the current LSE to the new LSE starting with the effective date specified in the wholesale transaction for the applicable Season. The transaction must be confirmed in the MECT by both parties before the start of the effective date.

5.7.3 Peak Load Contribution (PLC)

The EDC calculates each retail LSE's load ratio share of the retail LSEs peak Demand of the EDC's peak Demand at the MISO seasonal Coincident Peak Load prior to the Planning Year. The aggregate PLCs will be set equal to the seasonal Initial PRMR of the EDC. Specific methods used by the EDC to calculate each Retail LSE's PLC must be provided to both MISO and LSEs no later than December 15 prior to the upcoming Planning Year. LSEs will have until January 15 prior to the upcoming Planning Year to verify the seasonal EDC provided data in the MECT.

5.7.4 Settlements of Wholesale and Retail Switching

All confirmed load switching information submitted by the Settlements deadline (per the Market Settlements BPM) will be transferred to Market Settlements for settlement calculation purposes.

An LSE's seasonal Final PRMR will change based on the information submitted in the MECT for both Wholesale and Retail Load Switching.

MISO will calculate the new charges and credits by applying the seasonal Auction Clearing Price ("ACP") for the applicable LRZ to the new daily seasonal Final PRMR for each AO.

At the end of each weekly billing cycle, MISO will sum up the daily charges for each LSE for the weekly invoicing. The Market Settlements BPM provides more information regarding this process. An LSE's seasonal Final PRMR will change if Retail Load switching information in the

MECT or daily load data for Settlements is resubmitted per the Settlement's rerun process (i.e., S55, S105). Please see Market Settlements BPM for the Market Settlements Timeline.

5.8 Capacity Deficiency Charge

LSEs are allowed to opt out all or a portion of their seasonal Initial PRMR from participating in the auction by paying the Capacity Deficiency Charge. This is achieved by making a voluntary entry into the "Capacity Deficient Amount (MW)" field of the MECT equal to the MW amount of seasonal Initial PRMR opting out of the seasonal auction before the auction window opens. The Capacity Deficiency Charge for an LSE is the MW amount in the "Capacity Deficient Amount (MW)" field multiplied by 2.748 times the seasonal Cost of New Entry ("CONE") which is calculated by Annual CONE/365 multiplied by the days in the Season for the LRZ where the LSE's seasonal Initial PRMR is located.

LSEs that choose the RBDC Opt Out must demonstrate sufficient ZRCs to meet their seasonal Final PRMR (equal to the Initial PRMR) before the PRA auction window opens. Otherwise, the shortfall is subject to the Capacity Deficiency Charge by multiplying 2.748 times the seasonal CONE price.

Capacity Deficiency Charge revenues received by the Transmission Provider will be distributed on a *pro rata* basis based upon the cleared MW of seasonal Final PRMR to other LSEs in the Transmission Provider's footprint who did not opt to pay the Capacity Deficiency Charge. If the LRZ where the LSE opted to pay the Capacity Deficiency Charge failed to meet its seasonal LCR, then seasonal Capacity Deficiency Charge revenues will be allocated solely to LSEs within that LRZ that did not opt out of the seasonal auction by paying the seasonal Capacity Deficiency Charge. MISO will assess the seasonal Capacity Deficiency Charge on the first business day after the results of the seasonal PRA have been published.

6 Performance Requirements

6.1 Must Offer Requirement

The must offer requirement applies to any Market Participant who converts the SAC of a Capacity Resource to seasonal ZRCs, and those ZRCs are used in a seasonal FRAP or RBDC Opt Out or clear in a seasonal auction within the Planning Year. The must offer volume is the effective ICAP times the % of the total seasonal ZRCs a resource clears (for example, a unit eligible for 10 ZRCs that clears 5 will have a must offer of 50% of its ICAP), except for

Intermittent Resources. The effective ICAP equals the lesser of GVTC or Interconnection Service (NRIS+ERIS) for each Season (e.g. effective ICAP = Min(GVTC, IS)). The must offer obligation for Intermittent Resources is based on the cleared seasonal ZRCs, or ZRCs used in a FRAP or RBDC Opt Out, divided by the seasonal Resource credit (e.g. wind capacity credit for a wind resource) as described in Section 4.2.1.5 – Wind and Solar Capacity Credit. Additionally, no must offer requirement will exceed the resource's firm level of transmission service. LMRs do not have a must offer requirement, their obligations are covered in section 4.2.5 - Load Modifying Resource Obligations and Penalties.

6.1.1 Generation Resource but not Dispatchable Intermittent Resource or Intermittent Generation

MPs that own a Capacity Resource with ZRCs that clear in the PRA or are identified in a Fixed Resource Adequacy Plan (FRAP) or RBDC Opt Out must offer the ICAP equivalent of the cleared and FRAP or RBDC Opt Out ZRCs into the Day-Ahead Energy Market and the first post Day-Ahead Reliability Assessment Commitment (RAC) for every hour of every day, except to the extent that the Capacity Resource is unable to provide Energy, Contingency Reserve, or Short-Term Reserve due to a forced or planned outage or other physical operating restrictions consistent with MISO's Tariff. Outages and derates must be reported in the MISO Outage Scheduler (CROW).

Compliance with "must offer" requirements will be evaluated by MISO on a non-discriminatory basis. MISO will analyze compliance with "must offer" requirements in both the Day-Ahead and RAC by considering information provided by the MISO Outage Scheduler (CROW) and operational limitations, including, but not limited to, those related to fuel limited, Energy output limited or Intermittent Generation and Dispatchable Intermittent Resources.

6.1.2 Dispatchable Intermittent Resource and Intermittent Generation

An MP that owns a Capacity Resource that has ZRCs identified as part of a Fixed Resource Adequacy Plan (FRAP) or RBDC Opt Out or ZRCs which clear in a PRA must submit the ICAP equivalent MW value of the cleared ZRCs into the Day-Ahead Energy Market, and each pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment (RAC) for every hour of every day, except to the extent that the Intermittent Resource is unable to provide Energy, Contingency Reserve, or Short-Term Reserve due to a forced or planned outage or other physical operating restrictions consistent with MISO's Tariff.

The must offer requirement applies to the effective ICAP of the Intermittent Generation and Dispatchable Intermittent Resources, and not to the SAC amount. The must offer obligation for Intermittent Resources is replaced with the forecast in the DA market based on the weather forecast and performance of the Intermittent Resources.

For wind resources, the ICAP-equivalent must offer obligation is cleared ZRCs and/or ZRCs used in a Fixed Resource Adequacy Plan divided by the wind capacity credit. For non-wind Intermittent Generation and Dispatchable Intermittent Resources, the XEFORd will be set equal to the SAC divided by the ICAP, where the ICAP shall be the maximum value registered in the Commercial Model. For non-wind Intermittent Resources not modeled in the Commercial Model, the ICAP will be the nameplate capacity value as provided by the MP.

DA Reliability Forecast submissions for Intermittent Generation and Dispatchable Intermittent Resources received by the close of both the DA and Forward Reliability Assessment Commitment (FRAC) market offer periods will be used to monitor compliance with the must offer requirement when the unit's availability is affected by non-mechanical and/or non-maintenance reasons. The must offer monitoring process for Intermittent Generation and Dispatchable Intermittent Resources that submit a DA Reliability Forecast by DA Market close and FRAC close will check that the offers submitted are greater than or equal to the volumes submitted via the DA Reliability Forecast. The same Intermittent Forecast data file used in Day-Ahead Must Offer compliance shall be utilized in FRAC if no further update is provided. If a DA Reliability Forecast is submitted on time and in the correct format, it replaces the cleared Installed Capacity as the mustoffer requirement. Intermittent Resource Generation cannot submit a DA Reliability Forecast if being registered as a Use Limited Resource.

When submitting data to the Intermittent Resource Forecast Update tool, a header row should be included at the beginning of the file in this format; Resource, Day, Hour Ending (HE), and MW. The must offer monitoring process for Intermittent Generation and Dispatchable Intermittent Resources that do not to provide the DA Reliability Forecast by the DA Market close and the FRAC close, will be based on offers submitted and outages or derates submitted in MISO's Outage Scheduler (CROW). The must offer process will be based on the daily and hourly offers submitted by the Asset Owner. Additionally, maintenance and mechanical outages to Intermittent Forecasts will be based on the forecasts only. The thresholds established in Section 6.1 will not be used for Intermittent Generation and Dispatchable Intermittent Resources that provide the DA Reliability Forecast.

6.1.3 Use Limited Resource

An MP that commits a Capacity Resource that has ZRCs which clear in a Planning Resource Auction (PRA) or are used in a Fixed Resource Adequacy Plan must submit the ICAP value of ZRCs which either clear the PRA or is used in a Fixed Resource Adequacy Plan in the Day-Ahead Energy Market, each pre Day-Ahead, and the first post Day-Ahead Reliability Assessment Commitment (RAC) for every hour of every day, except to the extent that the Generation Resource is unable to provide Energy, Contingency Reserve, or Short-Term Reserve due to a forced or planned outage or other physical operating restrictions consistent with MISO's Tariff.

A Use Limited Resource is required to submit into the Day-Ahead Market to satisfy the must offer requirement of at least four (4) continuous hours daily across MISO's forecasted daily peak (including weekends). The must offer period of four (4) hours includes the two (2) hourly intervals prior to the forecasted peak hour, the peak hourly interval, and one (1) hourly interval after the forecasted peak load. This approach enables MISO to have an opportunity to schedule the Resource for the period in which the Use Limited Resource will not be recharging or replacing depleted resources. MISO's peak period will be based on the forecast published one day prior to the operating day in the Market Report section of the MISO website: https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports >Select "Summary" under Navigator to find the latest reports.
All outages and derates for Use Limited Resources need to be reflected in MISO's Outage Scheduler (CROW) or SDX. Thresholds for Use Limited Resources will only be applied during the four continuous hours across MISO's peak. MISO will not call upon a Use Limited Resource during its recharge hours, except in the case of an Emergency.

6.1.4 External Resources

The maximum must offer requirement applies to the registered capacity of the External Resource.

An MP that owns a Capacity Resource that has ZRCs which are identified in a Fixed Resource Adequacy Plan (FRAP) or RBDC Opt Out or clear in a PRA must submit the ICAP-equivalent value of FRAP or RBDC Opt Out or cleared ZRCs as Energy offers into the Day-Ahead Energy Market for every hour of every day, except to the extent that the Generation Resource is

unavailable due to a full or partial forced scheduled outage or the offers are from a Use Limited Resource. The must offer requirement will be capped at the resource's ICAP value.

Offers in the Day-Ahead Energy Market can only be Normal Energy type, with the transaction type of either fixed or dynamic. Dispatchable and market type of Day-Ahead cleared schedules are accounted for in the first post Energy and Operating Reserve Market. In addition, the Normal Energy type with the transaction type of either Fixed or Dispatchable offers with market type of Real-Time Energy and Operating Reserve Market only will also be considered in Day-Ahead Forward Reliability Assessment Commitment (FRAC).

Therefore, the must offer requirement for External Resources in FRAC is met by being available for declared capacity emergencies via MISO Market Capacity Emergency SO-P-EOP-00-002.

The MP that has either identified ZRCs from a FRAP or RBDC Opt Out or cleared ZRCs in a Planning Resource Auction (PRA) from an External Resource shall ensure the resource operator is reporting its outages and derates with their respective reliability coordinator. External Resources must be available to schedule Energy into MISO during Emergencies if needed by MISO. MISO Market Capacity Emergency SO-P-EOP-00-002 includes a mechanism to schedule all External Resources into MISO's Balancing Authority Area. BPM 007 Physical Scheduling Systems Section 15 explains how External Resources should be identified as Capacity Resources. External Resources should select "YES" in the Miscellaneous (MISC) field of the E-tag and the Token field must contain "MISOCR" in all capital letters with no spaces. In the Value field, the MP should list the Capacity Resource name that matches the Module E External Resource registration name in the MECT.

External Resources that are Use Limited Resources must follow the Day-Ahead must offer requirements for Use Limited Resources as documented in Section 4.2.2.1 of this BPM.

Compliance with must offer requirements will be evaluated by MISO on a non-discriminatory basis. MISO will analyze the compliance with must offers in both the Day-Ahead and RAC by considering information provided by MISO's CROW Outage Scheduler, and operational limitations, including, but not limited to, those related to fuel limited, Energy output limited, or Intermittent Generation.

6.1.5 DRR T*ype I and Type II*

The same must offer requirement described in Sec. 6.1 applies to the Installed Capacity of DRR Type I and Type II, (and not the SAC rating) used to meet Resource Adequacy Requirements. Installed Capacity refers to the amount of ZRCs cleared in an PRA and/or used in a Fixed Resource Adequacy Plan divided by (1 – XEFORd) of the Capacity Resource.

6.2 Must Offer Monitoring

MISO will monitor whether the offers submitted by the Asset Owner of each Capacity Resource in the Day-Ahead Energy and Operating Reserve Market, and first post Day-Ahead RAC process meets the seasonal must offer requirements. The must-offer requirements are in terms of Installed Capacity (ICAP) of the resource, where ICAP is the minimum of GVTC and Total Interconnection Service.

The offers should be greater than or equal to the seasonal must offer requirement minus approved outages or derates minus the applicable threshold as detailed in this section, but not to exceed the firm level of established Transmission Service. This excludes Capacity Resources that submit Intermittent Forecasts that have been accepted by MISO including DIR- registered Hybrid Resources.

[Firm Service] > [Offer] ≥ [Offer requirement] – [Outage or Derate] – [tolerance threshold]

If the offer amount is greater than or equal to the must offer requirement minus the approved outage or derate in CROW minus the appropriate threshold, then the MP will have passed the must offer monitoring check. Otherwise, the MP will not pass the must offer monitoring check. MISO will notify MPs through a report published on the market portal of their must offer status.

Outages & Derates

If the Offers for Day-Ahead and first post Day-Ahead RAC are less than the must offer requirement, then MISO will compare the difference to approved outages or derates in MISO's Outage Scheduler (CROW) for such resources. Approved outages, approved derates, and offers will be captured based on the information provided at both the Day-Ahead Energy Market close and first post Day-Ahead RAC close. DA Market close and first post Day-Ahead RAC close times are addressed in the Energy and Operating Reserve Markets BPM.

Tolerance Threshold

MISO will apply a tolerance threshold to all resources based on the must offer requirement listed in the MECT for the applicable Season. The thresholds were developed to recognize that data entry errors could occur when providing derate volumes through MISO's Outage Scheduler (CROW). Importantly, this does not relieve the MP of the obligation to meet the overall seasonal must offer requirement. The tolerance threshold volume will be applied at the CPNode level except for those resources noted otherwise in this BPM. The thresholds are as follows:

- The lesser of 10 MW or 10% for Capacity Resources greater than or equal to 50 MW
- The greater of 1 MW or 10% for Capacity Resources less than 50 MW

Market Participant Review

If a Market Participant believes there is a discrepancy in their must offer report, the Market Participant can notify MISO via the MISO Help Center of the discrepancy and submit supporting documentation. Outage information should include all revisions from the outage submission to the completion of the outage.

MISO will review the information submitted and notify the Market Participant within seven (7) Business Days via email of the outcome of the review.

IMM Access

The IMM also has access to the reports published on the market portal and may contact Market Participants directly on any compliance issues.

6.3 Annual Calculation of CONE

MISO will work with the Independent Market Monitor (IMM) to recalculate the CONE value for each LRZ annually by September 1 of each year for the following Planning Year. The CONE value for each individual LRZ will be the same in every Season (Summer, Fall, Winter and Spring).

In calculating CONE values, the IMM and MISO will consider the following factors:

- Physical factors: type of resource, location, costs for fuel
- Financial factors: debt/equity ratio, cost of capital, ROE, taxes, interest, insurance
- Other factors: permitting, environmental, Operating and Maintenance costs, etc.

MISO and the IMM will not consider anticipated net revenues from the sale of capacity, Energy, or Ancillary Services as factors in the annual recalculation of the CONE.

Once the IMM and MISO have calculated the CONE for each LRZ, MISO will make a filing with the Commission under Section 205 of the Federal Power Act seeking approval from the Commission for the re-calculated CONE. CONE values approved by FERC are posted on the MISO website.

Net CONE will be determined as per the section 69A.8 of Tariff Module E-1.

6.4 Replacement Resources

6.4.1 Maximum Outage & Derate Threshold (Greater than 31 day rule)

If a Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs is unable to meet the applicable performance requirements for the cleared ZRCs as described in Section 69A.5 for greater than thirty-one (31) Days in total due to full or partial Generator Planned Outage during the Season of the Planning Year in which the ZRCs cleared, or for Planning Resources that are subject to Diversity Contracts or Power Purchase Agreements for greater than one (1) Month during any Season of the Planning Year in which the ZRCs cleared, such Market Participant must replace the cleared ZRCs with uncleared ZRCs or new resources per Section 6.4.5 (On Ramping New Resources Mid-Planning Year for ZRC Replacement) to transfer the performance requirements applicable to the planning Resource or pay the Capacity Replacement Non-Compliance Charge (Tariff Module E-1 Section 69A.3.1.h). The CRNCC charge will be calculated after the completion of the season in the timeliest manner by MISO and the IMM.

The Must Offer Monitoring threshold described in section 6.2 (Must Offer Monitoring) will not apply when evaluating charges and ZRC replacement regarding the 31-day outage rule. The performance obligation is in terms of effective ICAP and thus the amount of ZRCs needed to be replaced will back calculate to ZRC values.

For example, a wind resource that has a 100 MW ICAP and 20 MW SAC and clears 20 ZRCs in the market will have a must offer requirement of 100 MW. The forecasts submitted to the DA market will overwrite the 100 MW requirement based on projected wind performance on an hourly basis. If the wind resource undergoes planned maintenance or repowering and planned

derates the facility to 80 MW ICAP for an entire Season, they will need to replace ZRCs when outages in a Season exceed 31 days since derate ICAP (must offer requirement – derates of facility 100-80=20MW) is greater than zero, and the amount of ZRCs to be replaced will be in SAC/ZRC terms. The original ICAP is 100 MW which resulted in 20 MW SAC, the resource is on a derate of 20 MW down to 80 MW, thus resulting in only 4 ZRCs needing replacement. 20 MW SAC / 100 MW ICAP = 20%, 20MW derate ICAP *20% = 4ZRCs. To complete the example, 80 MW ICAP*20% = 16 MW SAC. The cleared SAC obligation is 20 ZRCs, and the derate results in 16 ZRCs, therefore 4 ZRCs must be replaced, or charges assessed for any days over 31 in that Season.

$$\frac{20\ ZRC}{100\ ICAP} = 20\%\ Original; 20MW\ ICAP\ derate * 20\% = 4\ ZRC$$

Similarly, for conventional resources the conversion process is the same. For example, a 100 MW ICAP thermal resource has 50 MW SAC, if they clear all 50 ZRCs in the auction for that Season the must offer obligation is still 100 MW. If the resource is derated to 80 MW, the ZRCs needing to be replaced will be: 80 MW *50% = 40 MW, with a 50 MW SAC obligation, so 10 ZRCs would need to be replaced or charges assessed when the outage exceeds 31 days within that Season.

For resources that are completely offline due to planned or reasonably known outages for greater than 31 days, the penalty would be assessed on the cleared ZRCs of that resource, regardless of resource type. The CRNCC would be charged to the asset owner who converted SAC to ZRCs.

6.4.2 Attachment Y Retirement or Suspend Status

A Planning Resource used to meet seasonal RAR must be replaced by the registering Market Participant prior to the effective date of a status change to ‘retired’ or ‘suspend’ via an Attachment Y filing.

6.4.3 Transfer of Resource Adequacy Requirement and Performance Requirements through ZRC Replacement

ZRC replacement is available for use by Planning Resources that cleared a Season in the Planning Year and that go on suspension, retirement, catastrophic outage, ICAP Deferral, or that experience a Generator Planned Outage or derate greater than 31 days in that Season. Planning Resources already on a forced outage or knowingly offline during the effective date, cannot be used for ZRC Replacement. ZRC replacements are not allowed for any other reason.

In the event of such ZRC Replacement any performance requirements associated with the Resource that is being replaced (e.g., must offer obligation) will be transferred to the substituting Resource(s) for the duration of the ZRC Replacement period. ZRC Replacement is forward looking, MPs cannot replace ZRCs retroactively.

A Resource being used for ZRC replacement must not be on a full or partial Generator Planned Outage during the term of the ZRC replacement and must otherwise meet the applicable performance requirements set forth in section 69.A.3.1.h of Module E-1 of the Tariff.

6.4.4 ZRC Replacement Transactions

Replacement transactions in each Season can be entered at any time during the Planning Year and, unless otherwise modified, are valid through the end of the applicable Season within the Planning Year.

Replacement ZRCs may be sourced from any LRZ or ERZ subject to LCR, CIL, CEL, SREC, and SRIC constraints from the associated seasonal PRA. A replacement calculator is available in the MECT to check for any constraint violation. Planning Resource replacement transactions should be entered into the MECT tool at least seven (7) Calendar Days prior to effective date of replacement to ensure it has been entered and validated properly. This ensures adequate time for MPs and MISO staff to review and confirm accurate and proper entry of the ZRC replacement.

Replacement ZRCs can be from the Market Participant's own Planning Resources or ZRCs procured through a bilateral transaction from another Market Participant in the same seasonal auction These ZRCs can be sourced from other LRZ's provided they do not violate any LCR, CIL, CEL, SRIC or SREC. ZRC replacements from LRZs other than the original resource will be processed in accordance with the following parameters:

- ZRC replacement shall be processed on a first come, first served basis.
- The amount of cleared seasonal ZRCs in each LRZ at the time of a ZRC replacement shall be based upon the current amounts of cleared seasonal ZRCs, including any previous replacement transactions.

Replacement ZRCs should be input in the MECT with an intended effective date. The termination date of a Replacement ZRC transaction will be set as end of the Season by default. Market Participants can update the termination date to a different date before end of the

Season, provided that replacement capacity must be designated for RAR until at least 95% of its ZRCs have been replaced.

ZRC replacement shall have no impact on settlements from the PRA and FRAPs and RBDC Opt Out. The “Replacement Calculator” option is available in the MECT which can be used for verifying if the Planning resource being used for the replacement will meet all of the required LRZ parameters including LCR, CIL and CEL, as well as ERZ CEL.

6.4.5 On Ramping New Resources Mid-Planning Year for ZRC Replacement

If a new resource is expected to be available at the start of a Season within the Planning Year, the preferred course for the Market Participant would be to enter the ICAP Deferral process.

However, if a new resource is unable to utilize the ICAP Deferral Process, the new resource may be eligible to receive uncleared Zonal Resource Credits (ZRCs) in the middle of the Planning Year and prior to the start of a Season only under the following conditions:

i. Market Participant must coordinate with the IMM to obtain confirmation the new resource did not physically withhold capacity from a particular seasonal auction.
ii. The new resource must be in Commercial Model at time of request.
iii. The new resource must submit applicable testing (i.e. GVTC into MISO PowerGADS or Non-GADS Performance Template into MECT, DR tests, etc.).
iv. The new resource must become commercially operable as of date of replacement.
v. Requests must be submitted at least 3 weeks prior to start of replacement.
vi. If the new resource is an LMR no part of the Behind-The-Meter Generation (BTMG) or Demand Response (DR) assets can have been previously registered for the Planning Resource Auction by the registering Market Participant.
vii. If the new resource is an ARC LMR the contract with the customer/asset must have been signed after the March 1 Registration deadline.

6.4.6 MECT ZRC Replacement Calculator

The Replacement Calculator screen in the MECT is used to help MPs assess whether the ZRCs being used for the replacement will meet all of the required parameters including seasonal LCR, CIL, CEL, SREC, and SRIC.

For each Local Resource Zone, the Replacement Calculator screen displays the seasonal Final PRMR, LCR, CIL, CEL, sum of cleared Offers, sum of FRAP and sum of RBDC Opt Out, , Total Import and Total Export for each LRZ, and Total Export for each ERZ from the seasonal PRA.

Import Available and Export Available numbers are updated each time the Resource Replacement process is completed.

- Import Available number represents the maximum ZRCs allowed to import into the LRZ without violating the CIL in that Season. Import Available for the LRZ is calculated as:
  Seasonal Import Available = CIL – Total Import from PRA + (Sum of all Export* - Sum of all Imports*)
- LRZ Export Available number represents the maximum seasonal ZRCs allowed to export out of the LRZ without violating the CEL. Export Available for the LRZ is calculated as:
  LRZ Export Available = CEL – Total Export from PRA + (Sum of all Import - Sum of all Exports*)
  ERZ Export Available represents the maximum ZRCs allowed to export out of the ERZ without violating the CEL. It is calculated as: ERZ Export Available = ERZ CEL – ZRCs cleared, including FRAPs and RBDC Opt Out, in ERZ

Example:

LRZ 1 has an LCR of 15,070 MW; and Import Available of 4,628.7 MW
LRZ 2 has an Export Available of 1,023.7 MW
LRZ 3 has an Export Available of 1,759.4 MW
ERZ 1 has an Export Available of 1,000 MW

Total MW needing replacement in LRZ 1: = 200 MW (Original Resource = AAA1)

Replacement ZRCs from LRZ 1: Of that 200 MW, 100 MW will be replaced by other Planning Resources located in LRZ 1 (Substitution Resource = AAA2)

ZRCs in LRZ 1 (after same LRZ replacement): LRZ 1's total ZRCs from LRZ 1 after replacement = Offers Cleared + FRAP +RBDC Opt Out - Total MW needing replacement + Replacement ZRCs from the same LRZ = 18,522.3 – 200 + 100 = 18,422.3

LCR Test: Since 18,422.3 > LRZ 1's LCR of 15,070, the LCR Test result is "Pass"

Amount Exported: Remaining Replacement ZRCs of 100 MW are imported from LRZ 2 and LRZ 3:

o LRZ 2's Exported ZRCs = 40 MW (Substitution Resource = BBB3)
o LRZ 3's Exported ZRCs = 60 MW (Substitution Resource = CCC4)

Import Test: LRZ 1's total Imported ZRCs = 100 MW (40 MW + 60 MW). Since 100 MW < Import Available of 4,628.7, the Import Test result is "Pass"

Export Test: Since LRZ 2's Export of 40 MW < Export Available of 1,023.7 MW and LRZ 3's Export of 60 MW < Export Available of 1,759.4 MW, the Export Test results for LRZ 2 and 3 are "Pass".

This scenario will require the following 3 separate Resource Substitution Registrations to replace AAA1 for the full amount of 200 MW in LRZ 1:

o First 100 MW of AAA1: replaced by AAA2 for 100 MW from LRZ 1
o Second 40 MW of AAA1: replaced by BBB3 for 40 MW from LRZ 2
o Remaining 60 MW of AAA1: replaced by CCC4 60 MW from LRZ 3
o No change for ERZ 1

6.4.7 Capacity Replacement Non-Compliance Charge and Distribution

Any combination of cleared or replaced ZRCs that are on full or partial Generator Planned Outage for greater than thirty-one (31) Days in total during a Season, or for any other reason including full or partial Generation Outages that were not planned but were known or could have been reasonably anticipated at the time of the PRA, as set forth in the Market Monitoring and Mitigation Business Practices Manual, or unavailable because subject to a Diversity Contract that is not available for greater than one (1) Month during a Season, will be assessed a Capacity Replacement Non-Compliance Charge. The charges will be applied to the asset owner that converted the SAC to ZRCs for the resource . MISO's Control Room Operations Window (CROW) includes the following 4 categories of out of service (OOS) and derates: Planned, Urgent, Emergency and Forced. For purposes of calculating CRNCCs, MISO will use CROW outages prioritized as Planned. In addition, all outages not prioritized as Planned in CROW, but that were: (1) known or reasonably known at the time of the PRA, or (2) were determined by the IMM to be incorrectly prioritized in CROW shall be included in calculation of the CRNCC. See BPM-008 and the CROW users guide for outage prioritization codes and definitions.

Capacity Non-Compliance Charge = [# days failure to comply with replacement] * [# ZRCs failed to be replaced] * [Seasonal Zonal ACP + Daily Zonal CONE]

The number of Days counted will be on an hourly basis (31 days x 24 hours = 744 hours) since outages may only cover a portion of some Days. The number of hours that failed to comply or replace will be determined by ranking generator performance across the Season and applying charges to hours with the least violations in the Season beyond 744 hours. The charges assessed will round down to the number of whole Days in excess of 31 Days. For example, 815 hours minus 744 hours and then divided by 24 hours = 2.96 Days. In this case, the penalty charged for will be for two days.

Capacity Replacement Non-Compliance Charge revenues received by the Transmission Provider will be distributed to Market Participants representing LSEs that have met their Final PRMR during the applicable Season of the Planning Year on a pro rata basis, based upon their respective LSEs' share of total Final PRMR for the Transmission Provider Region.

6.5 LMR performance

6.5.1 BTMG Performance

When a BTMG that either is used in a seasonal FRAP or RBDC Opt Out or cleared in a seasonal PRA fails to perform during an Emergency when included in a Market Participant's Resource Deployment response to a Scheduling Instruction, the penalties are calculated for each hour in which a BTMG fails to respond in an amount greater than or equal to the target level of generation increase entered in the Resource Deployment screen of the LMR Scheduling Instruction Event in the DSRI as the sum of: (1) the product of (a) the amount of increased generation not achieved and (b) the LMP at the CPNode associated with the BTMG; and (2) applicable Revenue Sufficiency Guarantee (RSG) Charges. The amount of increased generation not achieved for BTMG is equal to the greater of: (1) the difference between (a) the target level of generation increases and (b) actual increased generation; and (2) zero. The applicable RSG Charges are equal to the product of: (1) the difference between (a) the target level of increased generation and (b) actual increased generation; and (2) the applicable RSG charges.

If advanced reporting is not entered in response to Scheduling Instructions into the Resource Deployment screen of the LMR Scheduling Instruction Event in the DSRI, then the full amount of Scheduling Instructions will be penalized.

The revenues from charges resulting from BTMGs that fail to respond in an amount greater than or equal to the MP responses to Scheduling Instructions shall be allocated, *pro rata*, to MPs representing LSEs in the LBA area(s) that experienced the Emergency, on a load ratio share basis.

For any situation where a BTMG does not increase generation in response to a Scheduling Instruction or where the resource is claimed to be unavailable as indicated in the DSRI as a result of maintenance requirements or for reasons of Force Majeure, MISO shall initiate an investigation into the cause of the BTMG not being available as needed during Emergency and may, if deemed appropriate, disqualify that resource from receiving ACP payments for that Planning Year. The BTMG may be called but not required to respond if the Emergency call is outside the resource's registration limitations (i.e. less than the registered time to respond, the event lasts longer than the registered duration, is made outside the BTMG's registered availability period; or the resource has reached its registered maximum number of deployments for that Season). However, should a BTMG resource indicate availability in the DSRI at any time in any Season of the Planning Year, it is considered available in the event of an Emergency during that Season and may receive Scheduling Instructions.

In the event the same BTMG does not sufficiently respond or is unavailable, except for reasons of Force Majeure or other acceptable reasons defined in the Tariff or in this BPM on a second occasion during a Season within the Planning Year (with a separation period of at least 24 hours), the MP that registered the BTMG will be subject to the penalties described herein (if that BTMG fails to increase generation to the level instructed). Such BTMG shall be assessed the same penalty as indicated above for its first performance failure, and the BTMG will no longer be eligible to receive ACP payments for the current Planning Year and for the next Planning Year.

If, in review of the BTMG's measurement and verification data following an Emergency, MISO determines that the MP has committed fraud to receive excess payments or to avoid penalties, MISO will have the right to ban the MP or its customers from participation in the wholesale electricity markets, as well as, pursue other legal options at the sole discretion of MISO.

6.5.2 DR Performance

If a DR that either is used in a seasonal FRAP or RBDC Opt Out or cleared in the seasonal PRA fails to perform during an Emergency when included in a Market Participant's Resource

Deployment response to Scheduling Instructions, penalties will be calculated for each hour in which a DR fails to respond in an amount greater than or equal to the target level of Load reduction entered in the Resource Deployment screen of the LMR Scheduling Instruction Event in the DSRI as the sum of: (1) the product of (a) the amount of load reduction not achieved, including Load above the registered firm service level for those DR registered as such and (b) the LMP at the CPNode associated with the DR; and (2) applicable Revenue Sufficiency Guarantee (RSG) Charges. The amount of Load reduction not achieved for DRs is equal to the greater of: (1) the difference between (a) the target level of Load reduction and (b) actual Load reduction; and (2) zero. The RSG Charges are equal to the product of: (1) the difference between (a) the target level of Load reduction and (b) actual Load reduction; and (2) the applicable RSG charges.

If advanced reporting is not entered in response to Scheduling Instructions into the Resource Deployment screen of the LMR Scheduling Instruction Event in the DSRI, then the full amount of Scheduling Instructions will be penalized.

Unless already entered as Self Scheduled for the event, DRs registered with a firm service level must still show a load reduction. Advanced Reporting should reflect the best estimate of load reduction available (i.e. load above the firm service level) during the event. Penalties will still be measured as load above the registered firm service level.

The revenues from charges resulting from DRs that fail to respond in an amount greater than or equal to the MP responses to Scheduling Instructions shall be allocated, *pro rata*, to MPs representing LSEs in the LBA area(s) that experienced the Emergency, on a load ratio share basis.

For any situation where a DR does not respond in an amount greater than or equal to the target level of Load reduction or registered firm service level or the resource is unavailable, including those circumstances where the resource is unavailable for maintenance reasons or Force Majeure, MISO shall initiate an investigation into the cause of the DR not being available when called upon, and may, if deemed appropriate, disqualify that resource from ACP payments for that Planning Year. The DR may be called but not required to respond if the Emergency call is outside the resource's registration limitations (i.e. less than the registered time to respond, the event lasts longer than the registered duration is made outside the DR's registered availability period, or the resource has reached its registered maximum number of deployments for that Season). However, should a Demand Resource indicate availability in the DSRI at any time in a

Season within the Planning Year, it is considered available in the event of an Emergency during that Season and may receive scheduling instructions.

In the event the same DR is not sufficiently responsive, including being unavailable, on a second occasion during a Season within the Planning Year (with a separation period of at least 24 hours) when included in a Market Participant's response to Scheduling Instructions; except when unavailable due to maintenance reasons, Force Majeure or other acceptable reasons as outlined in the Tariff or this BPM, the MP that registered the DR that was used to meet Resource Adequacy Requirements will be subject to the penalties described herein. The MP using the DR shall be assessed the same penalty as indicated above for a first performance failure, and the DR will no longer be eligible to receive ACP payments for the remainder of the current Planning Year and for the next Planning Year (s).

If, in review of the DR's measurement and verification data following an Emergency, MISO determines that the MP has committed fraud to receive excess payments or avoid penalties, MISO will have the right to ban the MP or its customers from participation in the wholesale electricity markets, as well as pursue other legal options at the sole discretion of MISO.

7 Integration of New LSEs

This section serves as a guide for those new Load Serving Entities (LSEs) integrating into MISO's region between the time MISO has completed the PRA(s) and the next Planning Year starts.

Once the integration date is set, MISO will work with both existing and new LSEs to ensure that the newly integrating LSEs have sufficient Planning Resources to meet their anticipated Coincident Peak Load Forecast plus an appropriate planning reserve margin.

To ensure the PRMR for new LSEs is met, MISO may conduct a Transitional PRA following the same registration requirements and auction protocols as the PRA.

MISO may provide the following when integrating new LSEs for applicable Season(s):

1. Define, as needed, new Local Resource Zone and their associated zonal parameters including:
    - Calculate CONE for the LRZ
    - Determine ZIA, ZEA, CIL and CEL

- LOLE Analysis (Section 3.4.2)
- Establishment of Local Reliability Requirement (Section 5.2.2.2)

2. Calculate Seasonal Planning Reserve Margin and Transmission Losses for the new LBAs
    - Determination of Seasonal Planning Reserve Margin (Section 3.4.1)
    - Review of CPD Forecasts (Section 3.2.5)
3. Conduct Transitional Planning Resource Auction
    - Amount of Capacity Cleared in Each Auction (Section 5.5.2)
    - Conduct of the PRA (Section 5.5.3)
    - Auction Results Posting (Section 5.5.8)

MISO may coordinate the proper timing of the data collection effort with the new LSEs for the successful completion of the Transitional PRA. The Transitional PRA will ensure that sufficient Planning Resources are procured to meet the Final PRMR of the newly integrating MISO region for the applicable Seasons in the remaining Planning Year.

The Resource Adequacy Timeline for the seasonal PRAs is shown in Appendix K. MISO will determine the Resource Adequacy timeline for the Transitional PRA and will publish it on the Resource Adequacy webpage under the Planning Section of the MISO public website. The Resource Adequacy timeline for the Transitional PRA will be reviewed by stakeholders prior to publishing on the MISO public website.

8 Testing Procedures and Requirements

8.1 Generator Real Power Verification Testing Procedures

MISO has developed generator test standards as documented in Appendix J that apply for Planning Years 2011-2012 and beyond.

9 Appendices

Appendix A – Wind Capacity Credit

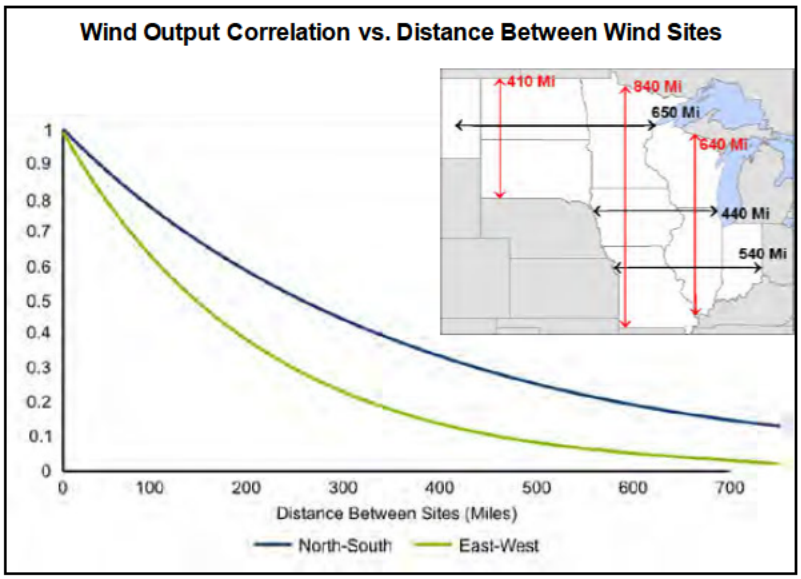
The goal of establishing wind accreditation is to estimate the reliable output of wind as a percentage of the Installed Capacity (ICAP), for each Season, for the MISO system and by Commercial Pricing Node (CPNode). The data driving wind accreditation includes the following:

- The hourly load and the hourly wind output for the sampled peak load period for each Season. This concurrent load and wind data, along with the normal complement of generator data in an LOLE simulation, is essential for determining the system-wide seasonal Effective Load Carrying Capacity (ELCC) of the wind fleet.
- The hourly wind output for the top 8 seasonal MISO coincident daily peak hours for the most recent 3 years' worth of operational data per Season, both for the MISO system and by individual wind CPNodes. The system-wide and individual CPNode performance and ICAP data is used to allocate the system-wide seasonal wind ELCC among the individual wind CPNodes currently in operation.
- The hourly amounts by which individual wind CPNodes are dispatched downward are part of Dispatchable Intermittent Resources (DIR) activity in the market. Non-DIR resources are not required to submit Day-Ahead Energy Market offers—subsequently, curtailments are only considered for DIR wind resources that do offer into the Day-Ahead Energy Market.

Since 2009, MISO has embarked on a process to determine the capacity value for the increasing fleet of wind generation in the system. The MISO wind accreditation process, as developed and vetted through the MISO stakeholder community, consists of a two-step method. The first step utilizes a probabilistic approach to calculate the MISO seasonal system-wide ELCC value for all wind resources in the MISO footprint. The second step employs a deterministic approach using unit-specific metrics to allocate the single seasonal system-wide ELCC value across all wind CPNodes in the MISO system, resulting in an individual wind capacity credit for each wind node in operation for the sampled peak load period for each Season.

As the geographical distance between wind generation increases, the correlation in the wind output decreases. This leads to a higher average output from wind for a more geographically diverse set of wind plants, relative to a closely clustered group of wind plants. Due to the increasing diversity and the inter-annual variability of wind generation over time, the process

needs to be repeated annually to incorporate the most recent historical performance of wind resources into the analysis. For each upcoming Planning Year, the wind capacity credit values in MISO are updated to account for both the stochastic nature of wind generation and the increasing integration of new resources into the system. The sections of this appendix and current results illustrated here are broken down to provide an example detailing the two-step method adopted by MISO for determining wind accreditation from the 2012-13 Planning Year.



Step-1: MISO System-Wide Wind ELCC Analysis

Probabilistic Analytical Approach

The probabilistic measure of load not being served is known as Loss of Load Probability (LOLP) and when this probability is summed over a time frame, e.g. one year; it is known as Loss of Load Expectation (LOLE). The accepted industry standard for what has been considered a reliable system has been the “Less than 1 Day in 10 Years” criteria for LOLE. This measure is often expressed as 0.1 days/year, as one year is the period for which the LOLE index is calculated.

Effective Load Carrying Capability (ELCC) is defined as the amount of incremental load a resource, such as wind, can dependably and reliably serve, while considering the probabilistic nature of generation shortfalls and random forced outages as driving factors to load not being

served. Using ELCC in the determination of capacity value for generation resources has been around for nearly half a century. In 1966, Garver demonstrated the use of loss-of-load probability mathematics in the calculation of ELCC [1].

To measure ELCC of a particular resource, the reliability effects need to be isolated for the resource in question, from those of all the other sources. This is accomplished by calculating the LOLE of two different cases: one “with” and one “without” the resource. Inherently, the case “with” the resource should be more reliable and consequently have fewer days per year of expected loss of load (smaller LOLE).

The new resource in the example shown in Fig. 1 made the system 0.07 days/year more reliable, but there is another way to express the reliability contribution of the new resource besides the change in LOLE. This way requires establishing a common baseline reliability level and then adjusting the load in each case “With” and “Without” the new resource to this common LOLE level. A common baseline that is chosen is the industry accepted reliability standard of 1 Day in 10 Years (0.1 days/year) annual LOLE criteria.

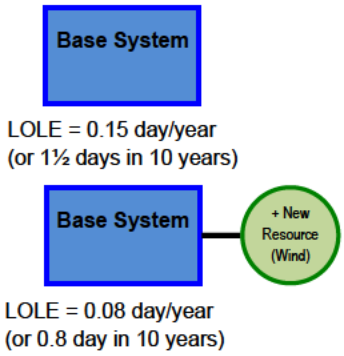


Figure 1: Example System “With” and “Without” New Resource

With each case being at the same reliability level, as shown in Fig. 2, the only difference between the two cases is that the load was adjusted. This difference is the amount of ELCC expressed in load or megawatts, which is 300 MW (100 minus -200) for the new resource in this example. This number may be divided by the ICAP of the new resource and then expressed in percentage form. ICAP for a wind resource is defined as the lesser of a wind resource’s Maximum Output as it is registered in the Commercial Model and its total Interconnection

Service. The new resource in the ELCC example Fig. 2 has an ELCC of 30 percent of the resource's nameplate capacity, assuming nameplate capacity is equivalent to ICAP.

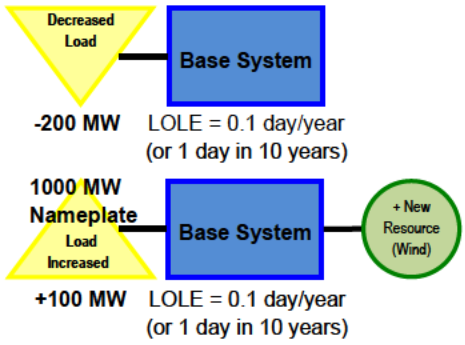


Figure 2: ELCC Example System at the same LOLE

The same methodology illustrated in the simple example of Fig. 2 was utilized as the analytical approach for the determination of the seasonal system-wide ELCC of the wind resource in the much more complex MISO system. For each historic year studied, there were two types of cases analyzed: cases with and cases without the wind resources included in the model. Each case was adjusted to the same common baseline LOLE and the ELCC was measured off those load adjustments. [2]

LOLE Model Inputs & Assumptions

To apply the ELCC calculation methodology, MISO uses an LOLE model capable of sequential Monte Carlo simulation to calculate LOLE values with and without the wind resource modeled. This analysis primarily considers three major inputs:

- Generator Forced Outage Rates (EFORd)
- Actual Historic Hourly Load Values
- Actual Historic Hourly Wind Output Values

Forced outage rates are used for the conventional type of units in the LOLE model. These EFORd are calculated from the Generator Availability Data System (GADS) that MISO uses to collect historic operation performance data for all conventional types units in the MISO system.

To incorporate historical performance, the actual historical hourly concurrent load and wind output at the wind CPNodes is used to calculate the historic seasonal ELCC values for the wind generation in the MISO on a system-wide basis.

Step-2: Wind Capacity Credit by CPNode Calculation

Deterministic Analytical Technique

Since there are many wind CPNodes throughout the MISO system, a deterministic approach involving a historic-period metric is used to allocate the system-wide seasonal ELCC values of wind to all the registered and in-service wind CPNodes. While evaluation of all CPNodes captures the benefit of the geographic diversity, it is important to assign the capacity credit of wind at the individual CPNode locations, because location relates to deliverability due to possible congestion on the transmission system in the MISO market. Also, in a market it is important to convey the correct incentive signal regarding where wind resources are relatively more effective. The location and relative performance are valuable inputs in determining the tradeoffs between constructing wind facilities in high-capacity factor locations, that in the case of the MISO system are located in more remote locations far from load centers, and requiring more transmission investment versus locating wind generating facilities at less effective wind resource locations that may require less transmission build-out.

The fleet-wide wind ELCC value (%) for a particular Season multiplied by the total ICAP for registered and in-service wind resources results in the total seasonal fleet-wide allocatable wind accreditation (MW). The total seasonal fleet-wide wind accreditation is then allocated to the applicable wind CPNodes in the MISO system.

Allocation considers the historic output, both in terms of with and without curtailments, for each wind CPNode over the top 8 daily peak hours for each Season included in the analysis. A capacity factor for each CPNode during all historical daily peak hours is represented in the Wind CPNode Equations contained in this appendix by "$PKmetric_{CPnode}$" for a particular CPNode, which is also referred to as the peak performance capacity factor.

This peak capacity factor for each Season is calculated using two methods:

- one method includes (adds back in) megawatts of a wind resource that were curtailed
- a second method excludes (does not add back in) those same curtailed megawatts

The larger of the two methods above, for each individual resource, forms the basis for allocating the total seasonal fleet-wide wind accreditation to the CPNodes.

New wind CPNodes that do not have sufficient historic output data will receive the seasonal fleet-wide wind capacity credit percentages applied to their ICAP as their default seasonal capacity accreditation for their first year in operation.

Tracking the top 8 daily peak hours in a Season is sufficient to capture the peak load times that contribute to the annual LOLE of 0.1 days/year. For example, in the LOLE run for year 2011, all of the 0.1 days/year LOLE occurred in the month of July, but only 4 of the top 8 daily peaks occurred in the month of July. Therefore, no more than 4 of the top daily peaks contributed to the LOLE. Other years have LOLE contributions due to more than 4 days, however 8 days was found sufficient to capture the correlation between wind output and peak load times in all cases. If many more years of historical data were available, one could simply utilize the single peak hour from each year as the basis for determining the $PKmetric_{CPnode}$ over multiple years.

Wind CPNode Equations

The relationship of the wind accreditation to a CPNode's ICAP and Capacity Credit (%) is expressed as:

$$(\text{Wind Capacity Rating})_{\text{CPNode n}} = \text{ICAP}_{\text{CPNode n}} \times (\text{Capacity Credit \%})_{\text{CPNode n}} \quad (1)$$

Where $ICAP_{CPnode\ n}$ = Installed Capacity of the wind facility at the CPNode level.

The right most term in equation (1) above, the $(\text{Capacity Credit \%})_{CPNode\ n}$, can be replaced by the expression (2):

$$(\text{Capacity Credit \%})_{\text{CPNode n}} = \text{K} \times (\text{PKmetric}_{\text{CPNode n}}\%) \quad (2)$$

Where "K" for was found by obtaining the PKmetric at each CPNode over the time period, and solving expression (3):

$$K = \frac{ELCC}{\sum_{1}^{n} (ICAP_{CPNoden} \times PKmetric_{CPNoden})} \quad (3)$$

This results in the sum of the Wind Capacity Rating (MW) calculated for the CPNodes approximately equal to the total fleet-wide seasonal wind ELCC.

References

[1] Garver, L.L.; "Effective Load Carrying Capability of Generating Units," Power Apparatus and Systems, IEEE Transactions on, vol. PAS-85, no. 8, pp. 910-919, Aug. 1966

[2] Keane, A.; Milligan, M.; Dent, C.J.; Hasche, B.; D'Annunzio, C.; Dragoon, K.; Holttinen, H.; Samaan, N.; Soder, L.; O'Malley, M.; "Capacity Value of Wind Power," Power Systems, IEEE Transactions on, vol. 26, no. 2, pp. 564-572, May 2011

Appendix B – GADS Events Outside Management Control (OMC Codes)

There are a number of outage causes that may prevent the Energy coming from a power generating plant from reaching the customer. Some causes are due to the plant operation and equipment while others are outside plant management control. Such outages include (but are not limited to) ice storms, hurricanes, tornadoes, poor fuels, interruption of fuel supplies, etc.

A list of GADS causes and their cause codes for OMC events are listed on the following page. MISO has generated a list of OMC codes accepted by MISO for GADS purposes. For more detailed information regarding OMC outages and codes please refer to Appendix K of the NERC GADS Data Reporting Instructions.

The lists of GADS Cause Codes applicable to reporting outages to MISO are as follows:

GADS Cause Codes Outside Plant Management Control (OMC)

3600	Switchyard transformers and associated cooling systems – external
3611	Switchyard circuit breakers – external
3612	Switchyard system protection devices – external
3619	Other Switchyard equipment – external
3710	Transmission line (connected to powerhouse switchyard to 1st Substation)
3720	Transmission equipment at the 1st Substation (see code 9300 if applicable)
3730	Transmission equipment beyond the 1st Substation (see code 9300 if applicable)
9000	Flood
9001	Drought
9010	Fire, not related to a specific component
9015	Pandemic
9020	Lightning
9025	Geomagnetic disturbance
9030	Earthquake
9031	Tornado
9035	Hurricane
9036	Storms (ice, snow, etc.)
9040	Other catastrophe

9130	Lack of fuel (water from rivers or lakes, coal mines, gas lines, etc.) where the operator is not in control of contracts, supply lines, or delivery of fuels
9132	Wet Fuel – Biomass
9135	Lack of water
9139	Ground water or other water supply problems
9150	Labor strikes company-wide problems or strikes outside the company's jurisdiction such as manufacturers (delaying repairs) or transportation (fuel supply) problems
9200	High ash content
9210	Low grindability
9220	High sulfur content
9230	High vanadium content
9240	High sodium content
9250	Low Btu coal due to low BTU vane of coal not expected (Outside Management Control)
9260	Low Btu oil
9270	Wet coal
9280	Frozen coal
9290	Other fuel quality problems
9300	Transmission system problems other than catastrophes (do not include switchyard problems in this category; see codes 3600 to 3629, 3720 to 3730)
9320	Other miscellaneous external problems
9500	Regulatory (nuclear) proceedings and hearings - regulatory agency initiative
9502	Regulatory (nuclear) proceedings and hearings - intervener initiated
9504	Regulatory (environmental) proceedings and hearings - regulatory agency initiated
9506	Regulatory (environmental) proceedings and hearings - intervener initiated
9510	Plant modifications strictly for compliance with new or changed regulatory requirements (scrubbers, cooling towers, etc.)
9520	Oil spill in Gulf of Mexico
9590	Miscellaneous regulatory (this code is primarily intended for use with event contribution code 2 to indicate that a regulatory-related factor contributed to the primary cause of the event)

Appendix C – Registration of Energy Efficiency Resources

Energy Efficiency	
Registration Requirements	**Explanation**
Name	Enter the name of the Energy Efficiency Resource
Plan Year	The Auction you are registering your Energy Efficiency Resource for displays in this field.
Description	Enter type of resources and additional names and sizes if registering more than one unit.
Asset Owner	Select the name of the entity that owns or has rights to this asset.
Local Resource Zone (LRZ)	The LRZ where this Energy Efficiency Resource is located displays once the Asset Owner and LBA is selected and the registration is saved.
Local Balancing Area (LBA)	Select the LBA where this Energy Efficiency Resource is located.
Documentation	Attach supporting documentation.
Program Information	Indicate if this is a new program or previously registered program.
Program Inception Auction	Select auction program began
Program Name	Name of program that is being registered.
Added Capability	Enter MW capability of program for given Auction
Total Capability	Total cumulative MW capability of program.
Eligible Capability	Sum of MW capability of 4 most recent Planning Years.
Forecast Capability	Total Capability minus Eligible Capability.
Energy Efficiency Capability at MISO Peak	MW value of program at MISO Peak.
Certify that registrant possesses ownership or equivalent contractual rights	Indicate whether registrant has all necessary rights to register this resource.
Comments	Submit any comments for this registration.

Appendix D – Registration of DRs

Demand Resource (DR)	
Registration Requirements	**Explanation**
Auction	The Season(s) in the PY you are registering your DR for displays in this field.
Name	Enter Name of the DR.
Description	Enter type of resources, additional names, and sizes if registering more than one unit.
Asset Owner	Select the name of the entity that owns or has rights to this asset.
Local Resource Zone (LRZ)	The LRZ where this DR is located displays once the Asset Owner and LBA is selected and the registration is saved.
Local Balancing Area (LBA)	Select the LBA where this DR asset is located.
Load Zone CP Node	Enter the CP Node where the DR asset is located.
CP Node Override	Check box if the Load Zone CP Node and Asset Owner combination that is needed, is not in the dropdown. MECT would allow then any Load Zone CPNode to be selected for any Asset Owner, assigned to the MP.
Aggregate Retail Customer (ARC)	Check box if resource registered as an ARC and fill out appropriate account and address information.
Retail Choice	Check box if Resource is for Retail Choice and if yes, type in name of Retail Choice Customer.
Accreditation Method	Choose accreditation method and attach supporting documentation.
Demand Reduction Capability Forecast	Monthly values shall be provided for the first two years from the Effective Start Date. Provide monthly MW levels associated with the amount of MW you can reduce in a given month consistent with the actual physical availability of the resource limited by any relevant regulatory or contractual restrictions.

Demand Resource (DR)	
Registration Requirements	**Explanation**
	Seasonal values shall be provided beyond the 2-year monthly window. Provide seasonal (Summer and Winter) MW levels associated with the amount of MW you can reduce in a given month consistent with the actual physical availability of the resource, limited by any relevant regulatory or contractual restrictions.
Operator Contact Name	Enter who to contact for deployment of the DR. The contact should be available 24 x 7 for commitment by MISO or LBA.
Operator Contact Phone Number	Enter phone number for 24 x 7 operator.
Operator Contact Email	Enter email address for 24 x 7 operator.
M&V protocol to be applied to this DR	Select the protocol that should be applied. This is used for determination of whether the LMR performed if called on during a MISO Emergency. If other selected, please describe in box.
Exclude Season	Check this box to exclude the registration from participation in the specified Season.
Capability at MISO Peak	Enter MW capability being registered at MISO's Seasonal Peak.
DRR Registered	Check box if resource is registered as a DRR. If yes, select the name of the DRR CP Node.
Emergency Demand Response (EDR)?	Check box if DR registered as an EDR. If yes, select the name of the EDR resource.
Load Control Method	Select if load is direct control or interruptible load.
Max Interruptions	Select the max interruptions for the resource.
Max duration (hours)	Select the max duration for the resource.
Notification	Enter the notification time required for this DR. Notification time(s) must cover all hours and cannot be more than 6 hours and should be available 24 hours/Everyday (From 0000 to 2300 acceptable for 24 hours). Multiple notification times should start and stop

Demand Resource (DR)	
Registration Requirements	**Explanation**
	with different hours (from 0000 to 0700, 0800 to 1600, 1700-2000, 2100 to 2300).
EP Node Details	Add an appropriate EP Node by clicking “Add EP Node” and upload documentation for details on the EP Node. Note: This is an optional upload on DR Registration
Accept terms and conditions of the MISO Tariff	Indicate whether registrant accepts the terms and conditions of the MISO Tariff applicable to this resource
Certify that registrant holds all permits in place to operate resource	Indicate whether registrant has all necessary permits to operate this resource
Certify that registrant holds all rights in place to operate resource	Indicate whether registrant has all necessary rights to operate this resource
Comments	Submit any comments for this registration

Appendix E – BTMG registration

Behind the Meter Generation (BTMG)	
Registration Requirements	**Explanation**
Auction	The Season(s) within the PY you are registering your BTMG for displays in this field.
Name	Enter Name of the BTMG.
Description	Enter type of resources and additional names and sizes if registering more than one unit.
Asset Owner	Enter the name of the entity that owns or has rights to this asset.
Local Resource Zone (LRZ)	The LRZ where this BTMG is located displays once the Asset Owner and LBA is selected, and the registration is saved.

Behind the Meter Generation (BTMG)	
Registration Requirements	**Explanation**
Local Balancing Area (LBA)	Select the LBA where this BTMG asset is located.
Load Zone CP Node	Enter the CP Node where the BTMG asset is located.
Documentation	Add supporting documentation as necessary.
Demand Reduction Capability Forecast	Monthly values shall be provided for the first two years from the Effective Start Date. Provide monthly MW levels associated with the amount of MW you can inject in a given month consistent with the actual physical availability of the resource, limited by any relevant regulatory or contractual restrictions. Summer and Winter values shall be provided beyond the 2-year monthly window for levels associated with the amount of MW you can inject in the given Summer and Winter Season consistent with the actual physical availability of the resource, limited by any relevant regulatory or contractual restrictions.
Operator Contact Name	Enter who to contact for deployment of DRBTMG. The contact should be available 24 x 7 for commitment by MISO or LBA.
Operator Contact Phone Number	Enter phone number for 24 x 7 operator.
Operator Contact Email	Enter email address for 24 x 7 operator.
M&V protocol to be applied to this BTMG	Select the protocol that should be applied. This is used for determination of whether the LMR performed if called on during a MISO declared Emergency. If other selected, please describe in box provided.
Exclude Season	Check this box to exclude the registration from participation in the specified Season
Generators	Select the name of the Generator(s)
Wind Capacity Factor %	If a wind unit is selected, the Wind Capacity Factor will be displayed.
Transmission Loss %	Indicates the Transmission Loss % to be applied to the UCAP calculation based on the LBA selected.
Capability at MISO Peak	Indicates the calculated MW value for the BTMG resource based on its GVTC

Behind the Meter Generation (BTMG)	
Registration Requirements	**Explanation**
XEFORd	Displays the XEFORd to be applied in the UCAP calculation for the BTMG resource. If multiple Generators are selected, this field will display the weighted average XEFORd.
Emergency Demand Response (EDR)?	Check box if BTMG registered as an EDR and if yes, select the name of the EDR resource
Max Interruptions	Select the maximum interruptions for the resource
Max Duration (hours)	Select the maximum runtime hours for the resource
Startup notification time details (in hours)	Enter the notification time required to deploy this BTMG. Needs to be no more than 6 hours and cover all hours. Needs to be available 24 hours/Everyday (From 0000 to 2300 acceptable). Multiple notification times should start and stop with different hours (from 0000 to 0700, 0800 to 1600, 1700-2000, 2100 to 2300)
EP Node Details	Add an appropriate EP Node by clicking “Add EP Node” and upload documentation for details on the EP Node. Note: This is an optional upload on BTMG Registration
Accept terms and conditions of the MISO Tariff	Indicate whether registrant accepts the terms and conditions of the MISO Tariff applicable to this resource
Certify that registrant holds all permits in place to operate resource	Indicate whether registrant has all necessary permits to operate this resource
Certify that registrant holds all rights in place to operate resource	Indicate whether registrant has all necessary rights to operate this resource
Comments	Submit any comments for this registration

Appendix F – External Resources

External Resources	
Registration Requirements	**Explanation**
Name	Enter name of the External Resource.
Description	Enter type of resources and additional names and sizes if registering more than one unit.
BER/COR	Indicate if this Resource is a Border External Resource or Coordinating Owner Resource by checking this box.
Auction	The Season(s) in the Planning Year you are registering the resource for displays in this field.
Asset Owner	Select the name of the entity that owns or has rights to this asset.
Load Zone CP Node	Select the required Load Zone CP Node where this Resource is serving load.
Local Balancing Area (LBA)	Select the LBA where the External Resource sinks within MISO.
Local Resource Zone (LRZ)	Indicates the Local Resource Zone where the load served by this resource is located.
Ownership	Indicate if the External Resource is directly owned or from a PPA.
Entitled Capacity	Enter MW value the Market Participant can register.
PPA Type	Select whether PPA MWs are defined in MISO ICAP or UCAP.
Generator	Select name of GADS or Non-GADS Generator.
Ownership Share Type	Select Megawatt or Percent to indicate how much capacity corresponds to the registration.
External Balance Area where Resource are located	Enter Balancing Authority where the resource is physically located.

External Resources	
Registration Requirements	**Explanation**
Capacity at MISO Peak (Calculated)	The amount of seasonal capacity on a megawatt basis corresponding to the registration in terms of NRIS and ERIS.
Interface CPNode	Select Interface Load Zone CPNode.
XEFORd	The seasonal forced outage rate associated with the Generator(s) from GADS, excluding Outside Management Control (OMC) events. Can be overridden by the Market Participant.
NERC Regional Entity	Select NERC Regional Entity where the resource is located.
Use-Limited Resource Qualification	Indicate if this resource meets all Use Limited Resource qualification requirements.
Diversity Contract	Indicate whether this resource is part of a Diversity Contract exchange.
IDC Name	Indicate the IDC name used for entering outages via the SDX. List separate IDC name for each unit being registered. This is used for the must offer requirement.
Documentation	If Resource is not owned directly, attach supporting PPA or other pertinent documentation here.
Firm transmission to the MISO Border	Input effective date and OASIS reservation number and select Transmission Provider.
Firm transmission within the MISO Transmission System	Input effective date and OASIS Reservation number.
Have you accepted the terms and conditions of the MISO Tariff ?	Indicate whether registrant accepts the terms and conditions of the MISO Tariff applicable to this Resource.
Have you notified the host BA?	Indicate if you have contacted your host BA of this registration.
Will this External Resource be used exclusively as a Capacity Resource for MISO?	Indicate that you certify that this External Resource is being used as a Capacity Resource exclusively for MISO.
Is this External Resource available the entire auction?	Indicate if this External Resource is available for the entire Season within the upcoming Planning Year.

External Resources	
Registration Requirements	**Explanation**
Have all other requirements been met?	Indicate if all other requirements have been met.
Resource Operator Contact Name (24x7)	Enter who to contact for deployment of External Resource. The contact should be available 24x7 for commitment by MISO or LBA.
Resource Operator Contact Phone Number (24x7)	Enter phone number for 24x7 operator.
Resource Operator Contact Email (24x7)	Enter email address for 24x7 operator.
Season(s) registration is being submitted for	Summer ☐ Fall ☐ Winter ☐ Spring☐
Comments	Submit any comments for this registration.

Appendix G – Reliability Based Demand Curve

Overview

The key features of the Reliability Based Demand Curve include:

- Target point defined by: (a) x-axis centered on MISO's reliability requirement at a loss of load expectation (LOLE) of 0.1 days per year; and (b) y-axis centered on the estimated Net CONE that would be needed to attract new resources. This target point reflects the central concept that price levels must be consistent with achieving system reliability objectives.
- Curve proportional to incremental reliability value, such that prices decline with increasing quantities of capacity, and such that pricing levels are rationalized against reliability risk across each of the four seasons.
- Price cap at 1 × Cost of New Entry (CONE, or Gross CONE) in each season, and 4 × CONE in total across the four seasons.

RBDCs are developed for the entire MISO system as well as for the two subregions (North/Central & South) of the MISO system, utilizing the same reliability-based concept. The demand curves for the subregions will reflect the additional reliability value that capacity resources can contribute by being located in a subregion with more acute reliability needs than the broader system. The total reliability value (and price) awarded to capacity in a particular subregion will reflect the sum of its contribution to avoiding system-wide reliability events (reflected in the system-wide RBDC) plus its contribution to avoiding additional reliability events that would occur in the subregion (reflected by the subregional RBDC).

In total, MISO utilizes twelve (12) RBDCs for any particular Planning Year: four (4) seasonal curves for the system-wide RBDC, four (4) seasonal curves for the North/Central subregion, and four (4) seasonal curves for the South subregion.

RBDCs are drawn in proportion to reliability value at each quantity point and are drawn through the target point at the reliability requirement and Net CONE.

System-wide Reliability Based Demand Curves

The system-wide RBDC is defined in proportion to system-wide Marginal Reliability Impact (MRI), which is measured as avoided Expected Unserved Energy (EUE), or the reductions

to load shedding that would be achieved by adding one more MW of perfect capacity (or UCAP) to the system. This is derived from the seasonal Loss of Load Hours (LOLH) predicted at a specific quantity of supply, and the observation that 1 MW of perfectly-available UCAP supply would have avoided 1 MW-hour of outages across all of the simulated events. Mathematically, MRI is defined as:

MRI = Avoided EUE from Incremental Capacity = LOLH x 1 MW UCAP

Where:

- MRI (MWh per UCAP MW) is the incremental reliability value of adding 1 UCAP MW of capacity to the system.
- Avoided EUE (MWh per season) is the reduction in expected involuntary load shedding caused by adding incremental capacity.
- Incremental Capacity (UCAP MW) is the volume of perfectly-available capacity added.
- LOLH (hours per season) is the number of shortage hours predicted in reliability simulations across the season in question, in correlation with a specific quantity of UCAP MW available in that season.

To calculate MRI as a function of capacity, MISO utilizes the same resource adequacy model used in the determination of resource adequacy Requirements.

MRI curves are convex and monotonically downward-sloping, reflective of the declining marginal reliability value of capacity when supply is abundant, as well as the increasing marginal reliability value of capacity when supply is scarce. MRI is calculated above and below the reliability requirement by first establishing the supply quantity at which the system achieves the reliability target, and then adding/subtracting perfectly-available UCAP MW (in equal increments of no less than 50 MW and no more than 250 MW) to determine the marginal reliability value of the incremental capacity.

EUE is calculated at consistent variances in incremental and decremental amounts of capacity in the model for each season. The starting point for the seasonal MRI curves is the amount of capacity (in terms of UCAP) that results in the LOLE criteria corresponding with the demonstrated risk for each season. The Monte Carlo modeling for the system-wide MRI curve is copper plate, which assumes no internal transmission limitations within the MISO system.

Subregional Reliability Based Demand Curves

The development of subregional MRI curves follows the same process used for developing the system-wide curves—however, with the addition of bi-directional subregional transfer limits in the resource adequacy model that exists between the two subregions.

The starting point for each subregion's MRI curve is the PRMR from the system-wide analysis. Decrease/increase capacity in one region and simultaneously increase/decrease capacity in the other by the same amount and record reliability metrics for each region individually and MISO as a whole.

Subregion-specific Net CONE values are used to calculate subregional scaling factors, which are multiplied by the subregional MRI curves in each season to calculate the subregional RBDCs. Subregional RBDCs reflect the additional reliability value associated with capacity that can avoid reliability events that occur only in that subregion due to import limits, but that are not experienced system-wide.

Beyond the import capability, only capacity located in that subregion can help to avoid those localized shortfall events, so the incremental reliability and pricing value awarded would only apply to local capacity resources. The subregional RBDCs are calculated considering only local outage events, not considering system-wide outage events that are driven by system-wide supply shortfalls. Therefore, the subregional RBDCs are defined as additive in nature to the system-wide RBDCs.

The role of the system-wide demand curve is to signal the value of adding more capacity in total in MISO, regardless of where it is located. The role of the subregional RBDCs is to signal where within the system capacity is most needed (and where additional capacity cannot be as effectively utilized).

The steps for calculating subregional RBDCs include:

1. Initialize the resource adequacy model with each subregion at a target of 0.1 days per year: Beginning with the system-wide resource adequacy model, apply subregional transfer limits. Then subtract capacity in each season until each subregion is at a minimum seasonal LOLE criteria of 0.01 days/season for seasons demonstrating minimal risk. This reliability target reflects the subregional interpretation resource adequacy criteria in the MISO Tariff used as the basis for setting starting points in the subregional RBDCs.

2. Calculate Subregional Seasonal resource adequacy metrics Across Reserve Margins for Each Subregion: From this starting point, add (or subtract) perfectly-available UCAP MW
   capacity to the subregion in each season. Adding capacity to the system and the relevant subregion and observing the change in LOLE, LOLH, and EUE measures the incremental value of locating capacity in that region. When the subregion in question becomes highly import-dependent, events in that subregion will become large (even though the broader system will maintain similar levels of reliability). When the region becomes a large exporter of capacity, local events will drop to zero (even though system-wide events will not drop to zero given that the maximum capacity limit will be enforced more often and local excess supply will not be possible to export in all cases).
3. Calculate Seasonal Subregional MRI Curves: The subregional MRI curve has a somewhat different meaning as compared to the system-wide MRI curve, in that the subregional MRI curve aims to measure the additional value achieved by locating capacity within a particular import-constrained region (beyond the value already reflected by the system-wide curve). Subregional MRI will be positive when the region is import-constrained and zero when the subregion has excess capacity. Therefore, the MRI curve for each subregion is first calculated as the total MRI including both system-wide and subregional events (the direct model result), and then the share of system-wide events is subtracted out. The resulting MRI curve reflects subregional events only.
4. Calculate the Subregional Scaling Factor: Calculate the subregional scaling factor from the subregional Net CONE value, divided by the subregional MRI at a quantity consistent with the resource adequacy target LOLE of 0.1 days/year from Step 1.
5. Calculate Seasonal Subregional RBDCs: Calculate the RBDCs for capacity in each subregion based on the MRI curve times the Subregional Scaling Factor from Step 4. The
   resulting subregional RBDC will produce a positive price whenever the subregion is anticipated to be import constrained during times of potential shortage, and incremental capacity in that subregion would help to alleviate the shortfall.

Translating MRI Curves to RBDC

Translating the MRI curves (in units of incremental EUE per MW) into a capacity demand curve (in units of dollars per MW-day) requires a system scaling factor. The system scaling factor is calculated so as to support annual average prices at annualized Net CONE when the system is at the annual LOLE requirement of 0.1 days/year. If more than one season shares a meaningful portion of the LOLE risk, the LOLE risk could be summed from the estimated values across 2–4 seasons. Mathematically, system scaling factor is defined as:

System Scaling Factor = Average System Annual Net CONE ÷ System MRI @ 0.1 LOLE

Where:

- System Scaling Factor ($/MWh) is the payment rate at which the system-wide Reliability Based Demand Curves would incentivize investment in additional supply.
- System Annual Net CONE ($/UCAP MW-year) is the administrative estimate of the net
annualized cost to develop new capacity resources (i.e., the long-run marginal cost of supply) on a system-wide basis.
- System MRI @ 0.1 LOLE (MWh/UCAP MW-year) is the marginal impact of additional capacity, as estimated on a system-wide copper-sheet basis (i.e., without considering transmission constraints) when the system is at the annual LOLE requirement of 0.1 days/year.

The prices on all the curves are derived by multiplying the MRI curves by the uniform system scaling factor (in $/MWh of EUE avoided) given by the annual break-even revenue requirement from the capacity market at the LOLH corresponding to a LOLE of 0.1 days/year.

Once the System Scaling Factor is calculated, the same value is utilized to calculate the RBDCs across all four seasons. The four RBDCs reflect a set of economic parameters that signal the relative value of capacity across each season. These four RBDCs will therefore support differentiated prices in each season that are always consistent with the level of events that are likely to be faced in each season given its respective supply-demand balance. The curves are all of a convex shape, reflective of the diminishing value of reliability at higher quantities but have different horizontal placements relative to peak load and different rates of diminishing return that reflect the unique system challenges faced across each season.

Summer has the highest peak load, so the curve is at the highest overall quantity in the summer—however, the other seasons face more uncertainty in net load across weather years and so their curves are more right-shifted compared to seasonal peak load. A season that faces
greater variability and uncertainties in outage and resource availability risks may also produce a
somewhat flatter curve (e.g., Winter and Summer), while a season facing fewer such uncertainties may produce a steeper curve (e.g., Spring).

Similar to System Scaling Factor, scaling factor to scale subregional MRI curve is determined as follows.

Subregional Scaling Factor = Average respective subregion Annual Net CONE ÷ subregional MRI @ 0.1 LOLE

Where:

- Subregional Scaling Factor ($/MWh) is the payment rate at which the Subregional Reliability Based Demand Curves would incentivize investment in additional supply.
- Subregional Annual Net CONE ($/UCAP MW-year) is the administrative estimate of the net annualized cost to develop new capacity resources (i.e., the long-run marginal cost of supply) on a subregional basis.
- Subregional MRI @ 0.1 LOLE (MWh/UCAP MW-year) is the marginal impact of additional capacity, as estimated on a subregional basis when the system is at the annual LOLE requirement of 0.1 days/year.

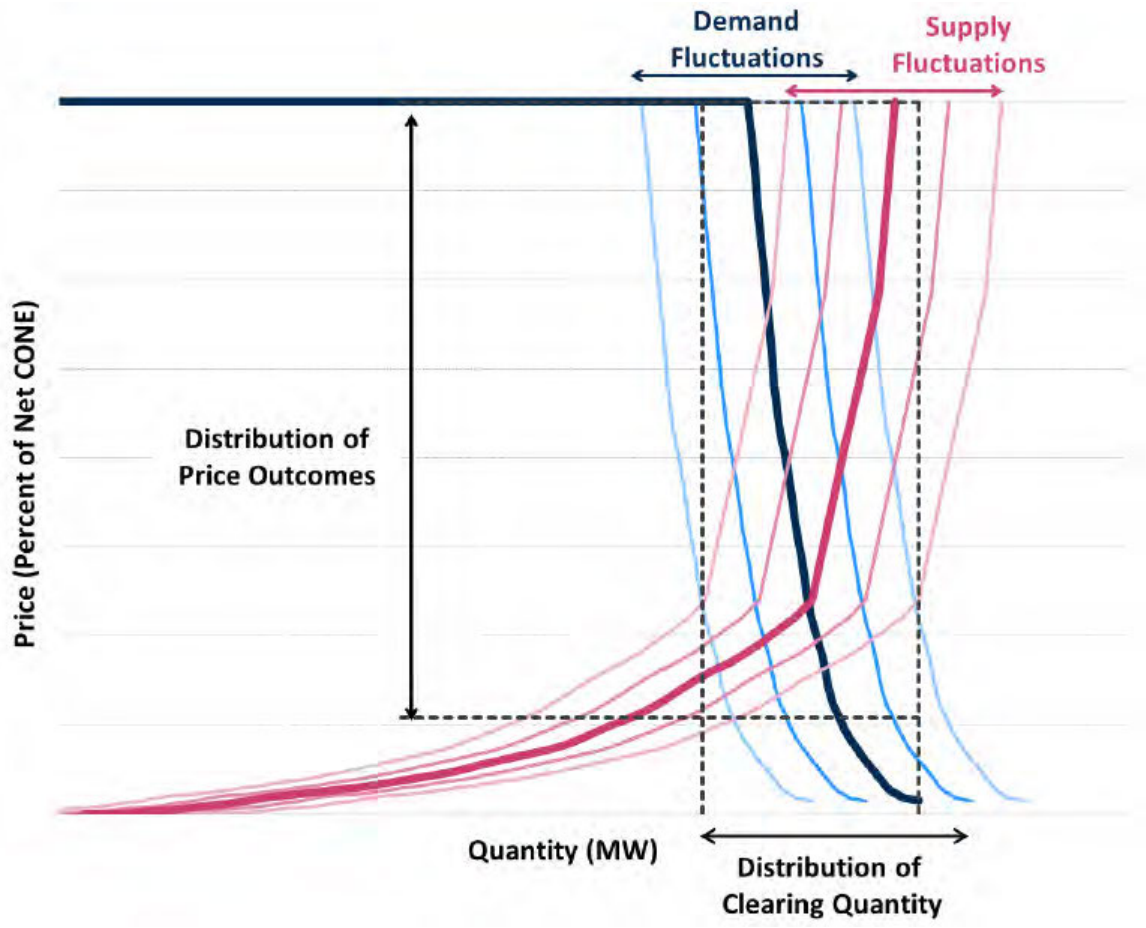
Once the Subregional Scaling Factor is calculated, the same value is utilized to calculate the RBDCs across all four seasons. The four RBDCs reflect a set of economic parameters that signal the relative value of capacity across each season. On subregion basis, these four RBDCs will therefore support differentiated prices in each season that are always consistent with the level of events that are likely to be faced in each season given its respective supply-demand balance. The curves are all of a convex shape, reflective of the diminishing value of reliability at higher quantities but have different horizontal placements relative to peak load and different rates of diminishing return that reflect the unique system challenges faced across each season.

Summer has the highest peak load, so the curve is at the highest overall quantity in the summer—however, the other seasons face more uncertainty in net load across weather years and so their curves are more right-shifted compared to seasonal peak load. A season that faces greater variability and uncertainties in outage and resource availability risks may also produce a somewhat flatter curve (e.g., Winter and Summer), while a season facing fewer such uncertainties may produce a steeper curve (e.g., Spring).

Long-run Equilibrium Analyses

Monte Carlo simulations are performed on supply curves and potential RBDCs to assess the achievement of long-run equilibrium conditions where the objective is for the average of all seasonal prices to be equivalent to Net CONE. Seasonal ACP and supply quantity outcomes are modeled in the simulations to account for variability in supply curve shapes, supply quantity, demand quantity, and opt out quantity. All model inputs are derived from historic MISO market data. Long-run equilibrium analyses should result in an expected distribution of price, quantity, and reliability outcomes that, when compared to the design objectives of RBDC, achieve the reliability objectives, produce better capacity market price signaling, and accurately recognize the reliability value of incremental capacity.

The long-run equilibrium analyses involve separate Monte Carlo simulations and will be performed every three (3) Planning Years.



In-market supply curves consist of three (3) component pieces:

6. Price Offers: supply offers at prices above zero, shape based on historic MISO offer curves, and independent of demand curve shape.
7. Year-to-Year Variability in Supply: zero-priced supply block, quantity varies with each draw to generate variability in supply offers, and tuned to true historic availability in supply.
8. Market Entry and Exit: zero-priced annual supply block with seasonal capacity ratings proportional to a combustion turbine reference resource, quantity varies across draws so that the average of seasonal clearing prices across all seasons is equal to the annual net CONE.

Appendix H – Non-Schedule 53 Seasonal Accredited Capacity (SAC) Calculations for Planning Resources

The following sets of equations establish how the SAC values (NRIS SAC, including E-NRIS SAC, and ERIS SAC) are determined for Planning Resources to account for resource performance and availability. Schedule 53 resource accreditation is outlined in Appendix Y.

H.1 Planning Resource SAC calculation for a Generation Resource, a Demand Response Resource backed by a generator, or a Behind-the-Meter Generator, with a Point of Interconnection on MISO's Transmission System

The Seasonal Accredited Capacity (SAC) calculation is based on resource type and volume of seasonal Interconnection Service, seasonal GVTC, and seasonal forced outage rate (XEFORd).

H.1.1 Planning Year SAC Calculation for each Season

The following steps are used to calculate NRIS SAC and ERIS SAC for each Planning Resource.

Determine ICAP:

The first step is to determine the Installed Capacity (ICAP) that the Planning Resource can reliably provide, which is equal to the lesser of its GVTC or its total volume of Interconnection Service (Network Resource Interconnection Service and/or Energy Resource Interconnection Service) granted either through MISO's Generation Interconnection Procedures or through a market transition deliverability test. The equation is shown below.

$$ICAP = \begin{cases} Total\ Interconnection\ Service,\ If\ GVTC > Total\ Interconnection\ Service \\ GVTC,\ If\ GVTC \leq Total\ Interconnection\ Service \end{cases}$$

Determine Total SAC:

The next step is to convert the resultant ICAP value into a Total SAC value by applying its seasonal forced outage rate (XEFORd).

A forced outage rate class average for each Season is used if the Planning Resource has a GVTC < 10 MW and has not submitted generator availability data or does not have sufficient generator availability data to calculate a forced outage rate specific to the Planning Resource. A

Planning Resource has sufficient generator availability data when it has a minimum of 12 months of generator availability data between September 1 and August 31 for the previous 3 years. The applicable class average for a Planning Resource is based on its unit size and type.

$$Total\ SAC = ICAP \times (1 - XEFOR_d)$$

If the Planning Resource has provisional Interconnection Service, then the Planning Resource will receive zero Interconnection Service and therefore the calculated Total SAC will be zero.

If the Planning Resource does not report historical outage data to GADS, its historical performance during seasonal peak hours should be provided to MISO through the Non-GADS Performance Template, which will leverage prior performance to establish seasonal GVTC values indicative of typical seasonal capabilities. In this case, XEFORd would not be used to reduce Total SAC. This process excludes Demand Response Resources.

Allocate Total SAC into NRIS SAC and ERIS SAC based on Interconnection Service:

The Resource's Total SAC is allocated into NRIS SAC and ERIS SAC based upon its type of Interconnection Service.

$$Total\ SAC = NRIS\ SAC + ERIS\ SAC$$

To the extent the Planning Resource has Network Resource Interconnection Service (NRIS) or was determined to be aggregate deliverable through the market transition deliverability test, then that quantity will be allocated first to calculate the NRIS SAC.

$$NRIS\ SAC = \begin{cases} ICAP * (1 - XEFORd), & If\ ICAP = NRIS \\ \big(Minimum\ of\ (NRIS, GVTC)\big) * (1 - XEFORd), & If\ ICAP > NRIS \end{cases}$$

The remaining balance of Total SAC is allocated to ERIS SAC (i.e. ERIS SAC = Total SAC – NRIS SAC.

$$ERIS\ SAC = \begin{cases} 0, & If\ ICAP = NRIS \\ Total\ SAC - NRIS\ SAC, & If\ ICAP > NRIS \end{cases}$$

Eligibility of NRIS SAC and ERIS SAC Conversion into seasonal Zonal Resource Credits

The NRIS SAC represents capacity in MW that is eligible to be converted into seasonal Zonal Resource Credits.

Effective ICAP

In determining the amount of ERIS SAC eligible for conversion into seasonal ZRCs, the deliverability of any ERIS must be determined prior to ERIS SAC conversion. ERIS must be paired with firm Transmission Service that covers the entire Season to be considered deliverable. NRIS is automatically considered deliverable and does not require an additional Transmission Service Request. The full amount of ERIS SAC can be converted to ZRCs if the resource is fully deliverable to its ICAP amount.

Total SAC which can be converted into seasonal ZRCs are the summation of the Planning Resource's NRIS SAC plus the lesser of the resource's ERIS with firm Transmission Service.

$$Total\ SAC\ Eligible\ for\ ZRC\ Convsersion\ = (NRIS\ SAC) + (ERIS\ SAC\ with\ TSR)^{*}$$

*Amount of TSR needed is dependent on ICAP amount

Ex	Size	NRIS	SAC	Total IS	GVTC	ICAP	Total SAC	NRIS SAC	ERIS SAC	TSR	ZRC
1	100	**100**	0	100	100	**100**	**75.0**	75.0	0.0	0.0	**75.0**
2	100	**50**	50	100	100	**100**	**75.0**	37.5	37.5	50.0	**75.0**
3	100	**50**	50	100	75	**75**	**56.3**	37.5	18.8	25.0	**56.3**
4	100	**0**	100	100	100	**100**	**75.0**	0.0	75.0	100.0	**75.0**

Examples for Illustrative Purposes

In example 3 above, a 100 MW Resource with 50 MW NRIS and 50 MW ERIS submitted a GVTC value at 75.

The ICAP will be 75 MW because the GVTC is less than the Interconnection Service of 100 MW.

Since the 50 MW NRIS is less than the Resource's ICAP, the Total SAC value of 56.3 MW of the Resource is not fully allocatable to NRIS SAC.NRIS SAC in example 3 was determined to be 37.5 MW. The remaining Total SAC minus the NRIS SAC is allocated into the resource's ERIS SAC. Thus, ERIS SAC level is 56.3 MW – 37.5 MW = 18.8 MW.

The resource would be credited with 56.3 MW of Total SAC which is comprised of 37.5 MW NRIS SAC + 18.8 MW ERIS SAC with firm Transmission Service for the corresponding seasonal PRA.

The resource was able to convert its entire Total SAC into seasonal ZRCs because the resource obtained full deliverability up to its ICAP, where 50 MW of NRIS plus 25 MW of firm Transmission Service is equal to its ICAP of 75 MW.

H.2 SAC calculation for a GADS-reporting External Resource that qualified as a Capacity Resource

The External Resource Capacity Resource SAC calculation is based on its seasonal GVTC and seasonal forced outage rate (XEFORd). The ERIS SAC is calculated by applying its seasonal XEFORd to its seasonal GVTC.

$$ERIS\ SAC = GVTC \times (1 - XEFOR_d)$$

A seasonal forced outage rate class average is used if the Capacity Resource has a GVTC < 10 MW and has not submitted generator availability data or does not have sufficient generator availability data to calculate a Planning Resource specific forced outage rate. A Planning Resource has sufficient generator availability data when it has a minimum of 12 months of generator availability data between September 1 and August 31 for the previous 3 years. The applicable class average for a Planning Resource is based on its unit size and type.

The ERIS SAC represents the capacity in MW that are eligible to be converted into seasonal Zonal Resource Credits with valid transmission service.

H.3 SAC calculation for a Planning Resource that is classified as Intermittent Generation and Dispatchable Intermittent Resources

For resources that don't report outage data to GADS, MISO calculates the Total SAC based on the past historical season-specific output assessing either the median for Run-of-River Hydro or

average for all other intermittent resources that are not wind resources. The calculation requires a minimum of 30 consecutive seasonal days of output for a unique seasonal accreditation value. If that is not available, a class average seasonal accreditation value will be applied to the nameplate of the resource. A capacity factor adjusted by the resource's deliverability is applied to the resource's Total SAC to determine the amount of Total SAC eligible to be converted into seasonal ZRCs.

For wind resources, MISO produces an annual wind capacity credit study for every Season in the upcoming Planning Year using the Effective Load Carrying Capability (ELCC) methodology, as described in Appendix A, to determine a fleet-wide SAC value to be allocated across all in-front-of-the-meter wind resources in that Season. Deterministic allocation of the total fleet-wide wind SAC across the studied wind resources is dependent on the reliability value of the entire wind fleet (as determined through probabilistic modeling) at the aggregate level and the historical performance history of the wind resources at the unit level during specific historical MISO system Coincident Peak Demand hours.

A capacity factor adjusted by the resource's deliverability is applied to the resource's Total SAC to determine the amount of Total SAC eligible to be converted into seasonal ZRCs.

BTMG wind Resource owners are required to submit the historical performance history of their BTMG wind Resources during specific historical MISO system Coincident Peak Demand hours for the purpose of accrediting these resources with a SAC value based on their performance during periods of MISO system seasonal peak Demand for the three prior applicable years for each Season. This results in resource-specific SAC values for each BTMG wind Resource in operation.

> *BTMG Wind SAC = [capacity factor over the 8 seasonal peaks over the past 3 years] * [k] * [ICAP]*
>
> *Where k = [seasonal MISO Fleet ELCC] / Sum of [Fleet ICAP * PKmetric] (see BPM-011 Appendix A)*

New wind Resources that do not yet have historical performance history for an entire Season would receive the class average wind capacity credit for that Season (as determined by the Wind and Solar Capacity Credit study produced every year) applied to the wind Resource's ICAP to derive an appropriate Total SAC value. Please reference Appendix A for more details regarding the accreditation procedure for wind Resources.

The amount of SAC eligible to be converted into seasonal Zonal Resource Credits will be based on the application of a deliverability-adjusted capacity factor.

H.3.1 Intermittent Generation and Dispatchable Intermittent Resources with a Point of Interconnection on MISO's Transmission System

The following sections establish how SAC values (NRIS SAC and ERIS SAC) are determined for Intermittent Generation and Dispatchable Intermittent Resources that have a Point of Interconnection on MISO's Transmission System to account for resource performance and deliverability.

H.3.1.1 Planning Year SAC Calculation for Wind Resources

The first step is to determine the total installed capacity of the wind Planning Resource, which is the Installed Capacity (ICAP). It is equal to the lesser of its seasonal GVTC (Registered maximum output in the Commercial Model) or its total volume of Interconnection Service (Network Resource and Energy Resource Interconnection Service) granted either through MISO's Generation Interconnection Procedures or through a market transition deliverability test.

The next step is to determine the resource's total SAC. MISO determines a unit-specific seasonal wind capacity credit, by CPNode, for each Planning Resource that is fueled by wind by allocating the total fleet-wide seasonal ELCC capacity. The wind capacity credit is determined by applying the larger of two allocation methodologies, as noted in Appendix A:

- one method which includes (adds back in) megawatts for wind resources that were curtailed (applies to DIR wind resources only)
- a second method excludes (does not add back in) those same curtailed megawatts

The larger of the two results becomes the individual resource's Total SAC.

$$Total\ \ SAC = GVTC \times (Wind\ Capacity\ Credit_{CPNode})$$

Determining Convertible SAC based on a Deliverability Adjusted Capacity Factor

The next step is to determine how much of the total SAC is eligible to be converted into seasonal ZRCs.

The total SAC for a wind resource is distributed into two categories for the purpose of determining the amount of Capacity eligible for conversion into seasonal ZRCs, either convertible SAC or undeliverable ERIS SAC.

To calculate convertible SAC, which is eligible to be converted into seasonal ZRCs, a Deliverability Adjusted Capacity Factor is first applied. The Deliverability Adjusted Capacity Factor uses historical seasonal peak observances of an intermittent resource and is calculated by 'capping' historical intermittent output during seasonal peak load observances to the resource's demonstrated deliverable amount divided by the resource's ICAP. Whereas a peak performance capacity factor also uses the same historical seasonal peak observances divided by the resource's ICAP but does not cap those observances.

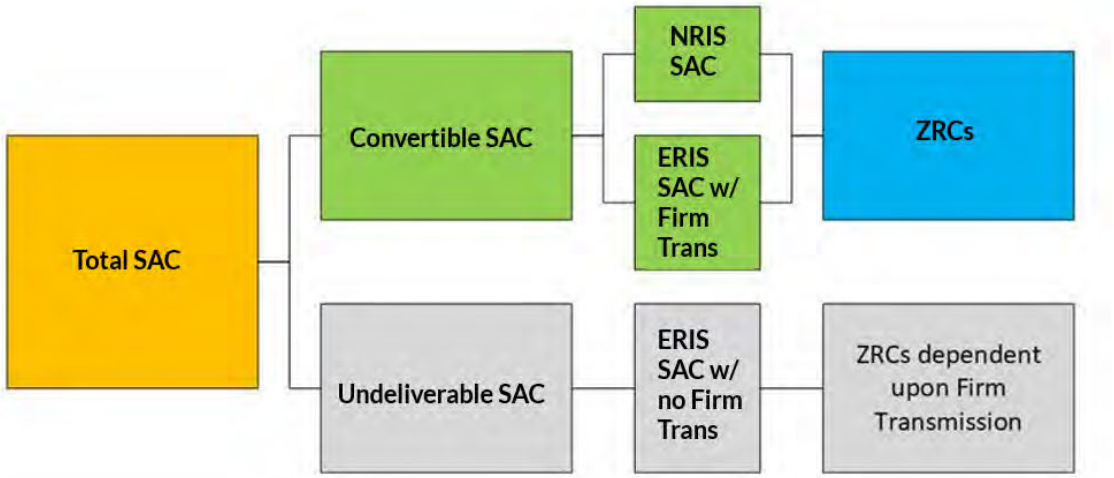
Formula for determining Convertible SAC

$$Convertible\ SAC = Total\ \ SAC * \frac{Deliverability\ Adjusted\ Capacity\ Factor}{Peak\ Capacity\ Factor}$$

The remaining Total SAC that is left after calculating Convertible SAC is considered the undeliverable ERIS SAC.

$$ERIS\ SAC = \begin{Bmatrix} 0, Total\ Interconnection\ SAC = \ Convertible\ SAC \\ Total\ Interconnection\ SAC - Convertible\ SAC, Total\ Interconnection\ SAC > Convertible\ SAC \end{Bmatrix}$$

Optionally, the classified undeliverable ERIS SAC can become eligible to be converted into seasonal ZRCs by procuring firm Transmission Service.

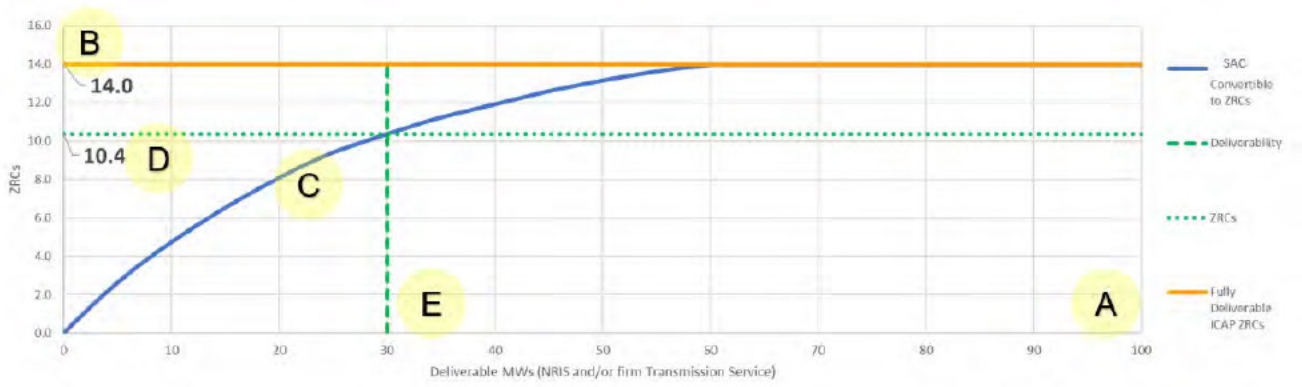


Converting ERIS SAC to Convertible SAC using the Resource's Deliverability Adjusted Historical Performance

ERIS SAC is not generally convertible to seasonal ZRCs at a one-to-one MW ratio. Each resource will have unique conversion data generated based on its past seasonal performance and deliverability which indicates the level of firm Transmission Service necessary to be obtained to gain a given level of seasonal ZRCs.

An example and further explanation is shown in the figure below:

ZRC Deliverability Curve Chart



Where:

A: Equals the maximum output of resource (RMax). In this example, this resource is 100 MW.

B: Total SAC, or SAC (Max) that can potentially be converted into seasonal ZRCs. This also represents the share of the total fleet-wide seasonal ELCC capacity. This value is based on the size and performance of the resource.

C: This is the Convertible SAC function which is the resource's Total SAC multiplied by the ratio of its Deliverability Adjusted Capacity Factor divided by its Peak Capacity Factor. Convertible SAC varies depending on the amount of Deliverability of the resource.

D: This is the resulting Convertible SAC value for a corresponding Deliverable amount in MW.

E: This is the amount of Deliverable MWs, or Deliverability. The point at which E intersects C provides the amount of seasonal ZRCs the Market Participant would obtain based on the size, performance, and deliverability of the resource.

H.3.1.2 Non-wind Intermittent Generation and Dispatchable Intermittent Resources

The first step is to determine the Total Installed Capacity that the Planning Resource can reliably provide, which is the Installed Capacity (ICAP). It is equal to the lesser of its GVTC, or its total volume of Interconnection Service (Network Resource and Energy Resource Interconnection Service) granted either through MISO's Generation Interconnection Procedures or through a market transition deliverability test.

The next step is to allocate the Total SAC based upon its type of Interconnection Service. To the extent the Planning Resource has Network Resource Interconnection Service (NRIS) or was determined to be deliverable through the market transition deliverability test then that quantity will be allocated first to NRIS SAC. The remaining Total SAC will then be allocated to ERIS. If the Planning Resource has provisional Interconnection Service, then the Planning Resource will receive zero Interconnection Service and therefore the calculated SAC will be zero.

$$NRIS\ SAC = \begin{cases} Total\ SAC, & Total\ SAC \leq NRIS \\ NRIS, & Total\ SAC > NRIS \end{cases}$$

$$ERIS\ SAC = \begin{cases} 0, & Total\ SAC \leq NRIS \\ Total\ SAC - NRIS, & Total\ SAC > NRIS \end{cases}$$

Determining Convertible SAC based on a Deliverability Adjusted Capacity Factor

The total SAC for an intermittent non-wind resource is distributed into two categories for the purpose of determining the amount of Capacity eligible for conversion into seasonal ZRCs. This would be considered Convertible SAC, either NRIS SAC or ERIS SAC coupled with firm Transmission, or undeliverable ERIS SAC (no associated firm Transmission).

To calculate convertible SAC, which is eligible to be converted into seasonal ZRCs, a Deliverability Adjusted Capacity Factor is first applied. The Deliverability Adjusted Capacity Factor uses historical summer peak observances of an intermittent non-wind resource and is calculated by 'capping' historical intermittent output during peak load observances to the

resource's demonstrated deliverable amount divided by the resource's ICAP. (See Appendix V for examples)

H.3.2 Intermittent Generation and Dispatchable Intermittent Resources that does not have Point of Interconnection on MISO's Transmission System

The following sections apply to Intermittent Generation and Dispatchable Intermittent Resources that do not have a Point of Interconnection on MISO's Transmission System. The ERIS SAC represents the capacity in MWs that are eligible to be converted into seasonal ZRCs.

Appendix I – XEFORd Calculation

XEFORd is equivalent forced outage rate Demand excluding events outside of management control (OMC). XEFORd will be calculated on a seasonal basis. A description and list of the MISO OMC events can be found in Appendix B. The MISO equation is:

$$\frac{(FOHd + EFDHd)}{(FOHd + SH + Synch\ Hours)} * 100\%$$

where:

SH = service hours
Synch Hours = synchronous hours
RSH = reserve shutdown hours

FOH_d = forced outage hours Demand = f_f x FOH
f_f = full forced outage Demand factor = $\frac{(\frac{1}{r}+\frac{1}{T})}{(\frac{1}{r}+\frac{1}{T}+\frac{1}{D})}$
r = average forced outage duration = (FOH)/(# of FO occurrences)
D = average Demand time = (SH + Synch Hours)/(# of unit actual starts)
T = average reserve shutdown time = (RSH)/(# of unit attempted starts)
FOH = forced outage hours

$EFDH_d$ = (f_p x EFDH)
AH = available hours
f_p = partial forced outage Demand factor = (SH + Synch Hours)/AH
EFDH = equivalent forced derated hours

Special cases are evaluated in the following order:

If reserve hours < 1, then f_f =1,
then if (SH + Synch hours) = 0, then f_f = 1,
then if (1/r + 1/T + 1/D) = 0, then f_f = 0,
then if # of FO occurrences = 0 or FOH = 0, then 1/r = 0,
then if RSH = 0 or # of unit attempted starts = 0, then 1/T = 0,
then if # of unit actual starts = 0 or (SH + Synch Hours) = 0, then 1/D = 0,
then if (SH + RSH + Synch Hours) = 0, then f_p = 0,
then if ((FOHd + SH + Synch Hours) = 0, then EFORd = 0

SH, RSH and Synch Hours are reported through the MISO Market Portal in the PowerGADS application by the users in their Performance data. The rest of the statistics are calculated by PowerGADS based on the user submitted Event data. Forced outage rates for each unit can be found in the Generator Outage Rate Program (GORP) report. The statistics used in calculating forced outage rates can be found in the Statistics Report, Performance Report, and the Seasonal XEFORd Report.

The MISO calculation is based on the EFORd equation defined in the NERC Generating Availability Data System Data Reporting Instructions Appendix and the IEEE Standard No. 762-2006 Standard *Definitions for Use in Reporting Electric Generating Unit Reliability, Availability and Productivity*. The MISO XEFORd calculation differs as follows:

- The NERC and IEEE EFDH formula is (Derated Hours * Size of Reduction)/Net Max Capacity while the MISO formula uses net dependable capacity rather than net max capacity and is (Derated Hours * Size of the Reduction)/Net Dependable Capacity. The size of the reduction is the Net Dependable Capacity minus the Net Available Capacity.
- MISO also includes synchronous hours in the XEFORd, average Demand time (D), and the partial Demand factor (f_p) calculations while NERC and IEEE do not.

Example XEFORd Calculations

Raw Data									
Unit	SH	Synch Hours	RSH	AH	Actual Starts	Attempted Starts	EFDH	FOH	FO Events
1	4,856	0	2,063	6,919	34	34	146.99	773	12
2	4,556	0	1,963	6,519	31	31	110.51	407	5
3	3,942	132	3,694	7,768	36	36	19.92	504	11
4	6,460	0	516	6,976	17	18	131.03	340	14
5	6,904	0	62	6,966	16	16	35.81	138	12

Calculated Values								
Unit	**1/r**	**1/T**	**1/D**	**f_f**	**FOHd**	**f_p**	**EFDHd**	**XEFORd**
1	0.0155	0.0165	0.0070	0.8205	634.25	0.7018	103.16	13.43%
2	0.0123	0.0158	0.0068	0.8049	327.61	0.6989	77.23	8.29%
3	0.0218	0.0097	0.0088	0.7813	393.78	0.5245	10.45	9.05%
4	0.0412	0.0349	0.0026	0.9666	328.63	0.9260	121.34	6.63%
5	0.0870	0.2581	0.0023	0.9933	137.08	0.9911	35.49	2.45%

Unit 3 Example XEFORd Calculation Detail

r = average forced outage duration = $\frac{FOH}{FO\ events} = \frac{504}{11} =$ 45.82 hours, then 1/r = 0.0218

T = Average reserve shutdown time = $\frac{RSH}{attempted\ starts} = \frac{3694}{36}$ = 102.61 hours, then 1/T = 0.0097

D = average Demand time = $\frac{(SH+synch\ hours)}{actual\ starts} = \frac{3942+132}{36} = 113.17$ hours, then 1/D = 0.0088

f_f = full forced outage Demand factor = $\frac{(\frac{1}{r}+\frac{1}{T})}{(\frac{1}{r}+\frac{1}{T}+\frac{1}{D})} = \frac{(0.0218+0.0097)}{(0.0218+0.0097+0.0088)} = 0.7816$

FOHd = forced outage hours Demand = f_f x FOH = 0.7813 x 504 = 393.78 hours

f_p = partial forced outage Demand factor = $\frac{(SH+synchhours)}{AH} = \frac{(3942+132)}{7768}$ = 0.5245

EFDH = fp x EFDH = 0.5245 x 19.92 = 10.45 hours

XEFORd = $\frac{(FOHd+EFDHd)}{(FOHd+SH+synch\ hours)} * 100 = \frac{(393.78+10.45)}{(393.78+3942+132)} * 100 = 9.05\%$

Units with 12 or more consecutive months of actual data: The XEFORd of a unit in service twelve or more full calendar months prior to the calculation month will be based on the number of consecutive months that that unit has data for up to 36 months.

Units with less than 12 consecutive months of actual data: The XEFORd of a unit in service less than twelve full calendar months shall be determined by the class average rate for units of the same type and within the same range of capability. A unit will use the class average value until 12 consecutive months of data is obtained and a new Planning Year begins. The class average will be the 5-year forced outage rate from the latest Loss of Load Expectation (LOLE) Study.

Units with Low Service Hours

Units with an average of less than 20 service hours per Season and attempted starts greater than zero will have their service hours adjusted if the unit has at least 12 consecutive seasonal months of GADS data. The adjusted service hours will be based on 60 service hours (20 service hours x 3 Seasons) or a fraction of 60 if there is less than 9 consecutive seasonal months of GADS data. This adjustment will be performed in the MECT. The calculation for the adjustment is as follows:

MO = consecutive seasonal months in operation
If SH = Service Hours < (MO/9*60) and attempted starts is greater than zero, then

SH' = seasonal adjusted low service hours = $\left[\left(\frac{actual\ starts}{atempted\ starts}\right) * \left(\frac{MO}{9} * 60 - SH\right)\right] + SH$

External Resources

Market Participants are responsible for making sure that GADS data is submitted for the External Resources that they are seeking qualification as ZRCs. The Market Participant can submit this data to MISO's GADS tool for the external resource or they can have the external resource submit the data. If an external resource is going to submit the GADS data, then they must receive access to the MISO Market Portal through their Local Security Administrator. If an External Resource does not have a Local Security Administrator, then it is the Market Participant's responsibility to receive and submit this data for the External Resource.

Catastrophic Outages

Catastrophic Outages are defined as forced outages that result in a unit being unavailable for a minimum of six (6) continuous months. A catastrophic outage may be a forced full or partial (forced derating) outage. A scheduled outage (planned, planned extension, maintenance, or maintenance extension) cannot be a catastrophic outage. For an outage to be considered catastrophic, the MP must notify the MISO Resource Adequacy team in writing within 75 days of determining the outage is a Catastrophic Outage, including a description of the Catastrophic Outage, start date of outage, expected return date, etc.

If the MP chooses not to replace a Planning Resource that suffers a Catastrophic Outage, then the XEFORd will be based on actual GADS data.

If the MP chooses to replace a Planning Resource that suffers a Catastrophic Outage, the XEFORd will be based on class average when the unit returns to service. The class average value will be used until 12 consecutive months of data is obtained and a new Planning Year begins.

Resource replacement must be completed within 75 days of catastrophic outage.
Resource replacement must be in accordance with section 6.4 of this BPM.
Once the unit returns from Catastrophic Outage, Planning Resource qualification requirements still apply. Partial replacements are allowed.

If the outage is a forced derate with total or partial replacement, or a full forced outage with partial replacement, the resources XEFORd upon returning to service will be the class average for the portion of the resource replaced and the actual XEFORd for the remainder of the unit. A blended XEFORd will be calculated by MW weighting the class average and actual XEFORd values.

For Schedule 53 resources that experience a catastrophic outage and replaced the ZRCs accordingly during the time the resource was unavailable, the time it is out will be considered non-RAR and would not be counted in the SAC calculation consistent with ZRC replacement section of this BPM and Appendix Y. In situations where this leads the resource to have less than 60 days of RAR performance history during the 3-year lookback period, the Schedule 53 resource would be granted Schedule 53 class averages for the impacted seasons.

Fleet Weighted Average Forced Outage Rates

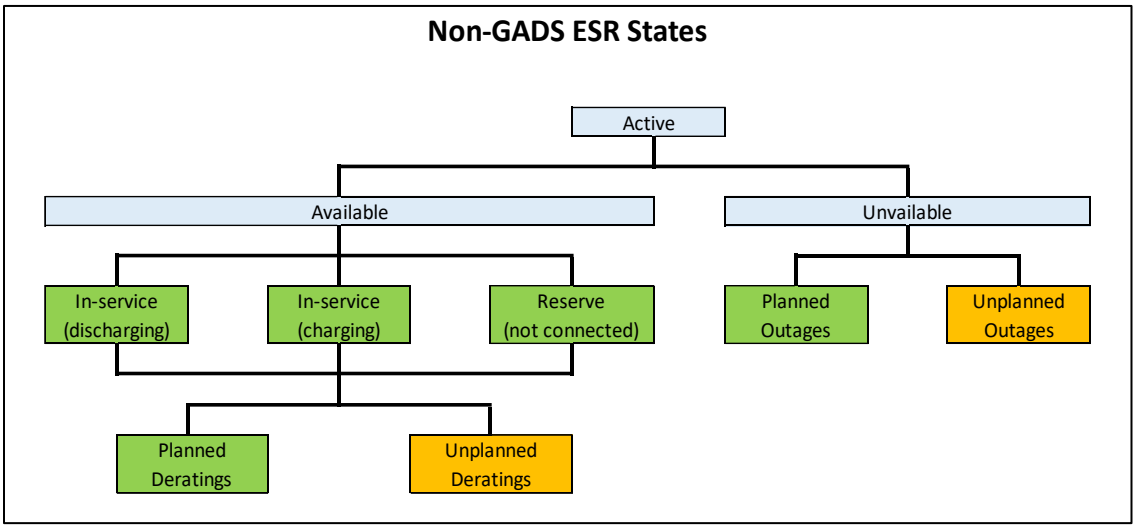
External Resources may participate using a fleet of resources. A weighted average forced outage rate is calculated using the individual unit forced outage rates and GVTC values. The resulting rate is applied to the total fleet GVTC to determine the fleet UCAP. See Appendix Q for more information regarding the Fleet XEFORd Calculation.

XEFORd for Non-GADS Electric Storage Resources (ESR)

The XEFORd for a non-GADS ESR is its Forced Unavailability and will be determined as follows.

A non-GADS ESR is forced unavailable when it is in an unplanned outage or an unplanned derating (see oranges boxes). All other states are unforced availability and include in-service

(discharging or charging), reserve (not connected), planned outages, or planned deratings (see green boxes).



An available resource that is not derated is 100% available. If a resources availability changes during an hour, the Forced Availability should be pro-rated. For example, if a 10 MW resource experiences a 23-minute Unplanned Outage during the hour, its equivalent Forced Unavailability would be (23 min/60 min) * 10 MW = 3.8 MW or 38%. Similarly, for an Unplanned Derating of 2.4 MW for 47 minutes of the hour the equivalent Forced Unavailability would be (47 min/60 min) * 2.4 MW = 1.9 MW or 19%.

Examples for a 10 MW resource	Unforced Availability (MW)	Forced Unavailability (MW)	Unforced Availability (%)	Forced Unavailability (%)
The resource is 100% available and in-service discharging	10.0	0.0	100.0%	0.0%
The resource is 100% available and charging	10.0	0.0	100.0%	0.0%
The resource is 100% available and in reserve not discharging	10.0	0.0	100.0%	0.0%
A portion of the resource is unavailable due to a planned derating and the remainder is available	10.0	0.0	100.0%	0.0%
4 MW of the resource is unavailable due to an unplanned derating and 6 MW is available	6.0	4.0	60.0%	40.0%
4.5 MW of the resource is unavailable due to a planned derating and 5.5 MW is unavailable due to an unplanned	4.5	5.5	45.0%	55.0%
The resource is unavailable due to a planned outage	10.0	0.0	100.0%	0.0%
The resource is unavailable due to a unplanned outage	0.0	10.0	0.0%	100.0%
23 minutes unplanned outage	6.2	3.8	62.0%	38.0%
2.4 MW unplanned derate for 47 minutes	8.1	1.9	81.0%	19.0%

Additional information:

- Pumped Storage Resources submit their availability and GVTC data through the MISO PowerGADS application.
- All other ESR types must submit their availability and GVTC (Hourly Equivalent Discharge Amount) data using the Non-GADS Performance template.
    - The template provides the 8 MISO coincident peak hours per Season for the last three years.
    - The average of these 24 seasonal unforced availability values is divided by the Hourly Equivalent Discharge Amount (MW) to calculate a seasonal unavailability factor.
    - Market Participants with less than 8 availability values in a Season will be given the default unavailability factor.
- Availability Reporting is optional for resources less than 10 MW. Resources that choose not to report, will be given the default unavailability factor. Once a resource chooses to report for the first time, they will be required to report every year thereafter.

Appendix J – GVTC Testing Requirements

J.1 Overview

All Generation Resources, External Resources, Behind the Meter Generation (BTMG) and Demand Response Resources backed by BTMG that intend to qualify as a Planning Resource are required to perform a real power test or provide past operational data. This test, or past operational data, shall be used to determine a planning resource's GVTC value. GVTC data is submitted through the MISO Market Portal into MISO PowerGADS.

Each seasonal corrected net test capability is the gross output (MW) that a planning resource can sustain averaged over the test period, if there are no equipment, operating, or regulatory restrictions, less station service and process load served, corrected to MISO coincident seasonal peak conditions.

			(A)	(B)	(C)	(D)= (A)-(B)-(C)	(E)	(F)	(G)	(H)= (D)+(E)+(F)+(G)
NERC Unit Type		Example Unit	Gross (MW)	Station Service (MW)	Process Load Served (MW)	Net Test Capacity (MW)	Air Temperature Correction (MW)	Relative Humidity Correction (MW)	Cooling Water Temperature Correction (MW)	Net Corrected (MW)
Combined Cycle	CC	CT1	95.0	1.0	0.0	94.0	-15.0	-0.1	N/A	78.9
Combined Cycle	CC	ST1	300.0	15.0	0.0	285.0	N/A	N/A	-1.0	284.0
Combined Cycle	CC	Unit 4	250.0	5.0	100.0	145.0	-3.5	-0.1	-0.5	140.9
Combustion Turbine	CT	CT3	50.0	0.1	0.0	49.9	3.0	0.1	N/A	53.0
Diesel	DS	Diesel 5	2.5	0.0	0.0	2.5	N/A	N/A	N/A	2.5
Fluidized Bed Combustion	FB	Unit 4	200.0	10.0	0.0	190.0	N/A	N/A	-2.0	188.0
Hydro	HD	Hydro 12	10.0	0.0	0.0	10.0	N/A	N/A	N/A	10.0
Nuclear	NU	Unit 1	1,000.0	50.0	0.0	950.0	N/A	N/A	-1.5	948.5
Pumped Storage	PS	Unit 5	300.0	1.0	0.0	299.0	N/A	N/A	N/A	299.0
Fossil Steam	ST	Unit 2	600.0	30.0	0.0	570.0	N/A	N/A	-3.0	567.0

GVTC Table J.1 – Examples of net corrected net test capability for different unit types. **Examples may not be representative of your situation. If you have unit specific questions, please contact Resource Adequacy.

If a Planning Resource fails to perform a real power test and report the test data to MISO's PowerGADS byOctober 31 prior to the start of the planning year t, it will result in the Planning Resource not qualifying as a Planning Resource and will receive zero SAC MWs for the upcoming Planning Year.

J.1.1 Test Period and Reporting Deadline

The real power test shall be performed between September 1 and August 31 prior to the upcoming planning year. The test data shall be submitted no later than October 31.

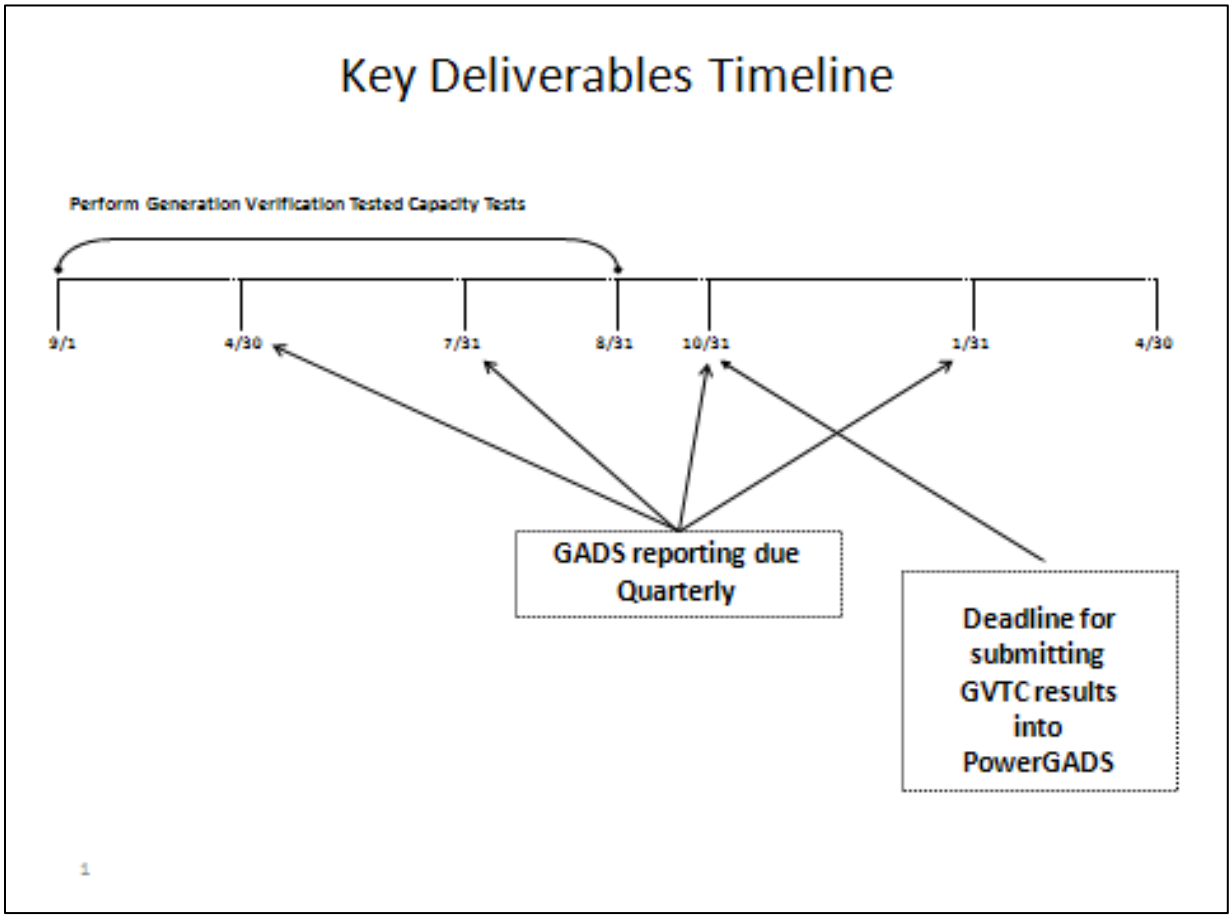
Example: For the 2023-2024 planning year (June 1, 2023 through May 31, 2024), the test must be conducted between September 1, 2021 and August 31, 2022, and submitted no later than October 31, 2022 to qualify as a Planning Resource for the upcoming Planning Year.

J.2 When to Perform and Submit a Generation Verification Test Capacity

Generation Resources, External Resources, Demand Response Resources backed by behind the meter generation, or Behind the Meter Generation that qualified as Planning Resources for the current Planning Year shall submit their GVTC no later than October 31 to qualify as a Planning Resource for the upcoming Planning Year. A real power test shall be performed, or past operational data may be used, during the period between September 1 and August 31 prior to the upcoming Planning Year. In addition to performing and submitting GVTC data to qualify as a planning resource for the annual capacity auction, a planning resource must conduct a test and submit data when:

- a modification that changes, increases, or decreases, the rated capacity of a unit is completed,
- returning from a suspension,
- returning to MISO after an absence including but not limited to, catastrophic events,
- not qualifying as a Planning Resource under Module E-1
- being qualified as a Planning Resource for the first time
- or for a Planning Resources in an approved “Suspension” status.

If a Planning Resource is unable to complete a real power test, the responsible MP must include the timing and cost requirements to complete a test when requesting a facility specific reference level.



J.3 Corrections to Establish GVTC

The GVTC shall be corrected to the average conditions of the date and times of MISO's four seasonal coincident Peaks, measured at or near the generator's location, for the last 5 years. MISO publishes the date and time of the past 5 seasonal coincident Peaks. When local weather records are not available at the plant site, the values shall be determined from the best data available (i.e., local weather service, local airports, river authority, etc.).

The corrections required to establish the GVTC of a unit include, as appropriate for each electric generating technology, dry air temperature, relative humidity, cooling water temperature, fuels, steam heating loads, reservoir level, nuclear fuel management programs and scheduled reservoir discharge.

J.3.1 Process Load Reporting in MISO PowerGADS to Establish GVTC

The Generator Owner shall forecast the maximum process load (PL) expected to be present at the time of the upcoming MISO seasonal peaks. MISO publishes the date and time of past coincident seasonal peaks as a reference for predicting the PL that is forecasted to be present at the time of the upcoming MISO peaks.

For calculating GVTC, the PL being forecasted and reported by the Generator Owner is allocated to the underlying generating unit of the Planning Resource and deducted from a unit's gross MW unless provisions are in place to curtail the load in the event of a MISO Capacity Emergency, or for electric load, is included in an LSE forecast. If such provisions for curtailment are in place or, for electric load, it is included in an LSE forecast, the PL is non-firm for the purpose of calculating GVTC.

Process Load can be electric load or thermal load in the case of a Combined Heat and Power (CHP) facility. Thermal PL is converted to units of MW by determining the reduction of power output caused by serving that load. Thermal loads can be PL because steam that would have otherwise been used to drive turbines to produce electricity may have been diverted to support process load, thus reducing the electrical capacity of the overall plant relative to the MISO system.

Thermal load that causes an increase in power output, as served from a back-pressure turbine for example, is not a PL for these purposes. However, the GVTC test should be performed or corrected for conditions that are a conservative expectation of the amount of thermal load that would be present coincident with MISO peak load conditions.

PL can be firm or non-firm. The following criteria should be applied to determine whether the PL is firm or non-firm:

- PL is firm if it continues to exist when one or more of the underlying generating units of the Planning Resource are derated or out of service. Such firm PL would be served by one or more of the underlying generating units of the Planning Resources at the same location or from the MISO system.
- PL is non-firm if it does not continue when the underlying generating unit of the Planning Resource is out of service.
- To the extent that PL that continues to exist when the underlying generating unit of the Planning Resource is out of service is served by resources that are not Planning Resources, such as auxiliary boilers, that portion of the PL is non-firm.

The amount of firm PL will be adjusted by multiplying by (1+PRM) and dividing by (1-XEFORd). The sum of the firm and non-firm PL will be reported in PowerGADS.

PL = (adjusted firm PL) + (non-firm PL)

Adjusted firm PL = firm PL * (1 + PRM) / (1 - XEFORd)

PL calculations are performed outside of PowerGADS and the MECT. PL is only deducted from an underlying generating unit of the Planning Resource's gross MWs one time. PL is part of the GVTC calculation that is entered into PowerGADS. MISO performs a PowerGADS integration that retrieves the GVTC value from the PowerGADS data base and populates the MECT. A Planning Resource may be comprised of one or more underlying PowerGADS units.

The UCAP PRM is from the most recent LOLE Study Report. The XEFORd is the appropriate value for the 36-months ending on August 31 proceeding the planning year, which can be found in PowerGADS.

J.4 Generation Verification Test Capacity During a Derate

A Market Participant that performs a GVTC when a unit has a documented derate in MISO PowerGADS can request MISO to adjust its GVTC if the documented derate in MISO PowerGADS lasted a minimum of 90 consecutive days prior to the test date and generator availability data has been reported to MISO prior to any adjustments to the GVTC. The Market Participant shall contact MISO's Resource Adequacy Department for a review of its request.

J.4.1 Interconnection Service Limitations

All Planning Resources GVTC are subject to Interconnection Service limitations to the bus to which the facility is currently or about to be connected to as verified by the Transmission Service Planning Department of MISO.

J.5 GVTC Real Power Test Requirements by NERC Unit Type

J.5.1 Fossil Steam (FS), Fluidized Bed Combustion (FB), and Nuclear (NU)

The test shall be at least two (2) continuous hours and data shall be averaged over the test period.

The impact of the observed steam turbine exhaust pressure will be corrected to the past five years average rated daily maximum circulating water temperature measured at the unit location, at the date and time of MISO's coincident peaks.

J.5.2 Combined Cycle (CC)

The determination of the GVTC of a combined-cycle unit will depend on the structure of the unit and its components. The steam turbine and combustion turbine(s) shall adhere to the guidelines in this manual. In the case of thermally dependent components the determination of the GVTC shall require the operation of both combustion and steam turbine components simultaneously. The output of the components can be netted to determine the combined-cycle unit GVTC.

The test shall be at least two (2) continuous hours and data shall be averaged over the test period.

For each Season, the impact of the observed steam turbine exhaust pressure will be corrected to the past five years average daily maximum circulating water temperature measured at the unit location on the day of MISO's Coincident Peak.

The impact of the observed ambient air temperature and relative humidity on combustion turbine performance will be corrected to the past five years average rated conditions experienced at the unit location measured at the date and time of MISO's Coincident Peaks. Where inlet cooling is used to reduce inlet air temperature, the temperature at the discharge of the inlet coolers shall be the basis for ambient temperature adjustment.

J.5.3 Miscellaneous (MS)

The test shall be at least two (2) continuous hours and data shall be averaged over the test period.

The test will be seasonally corrected per J.3 Corrections to Establish GVTC.

J.5.4 Combustion Turbine (CT)

The test shall be at least one (1) continuous hour and data shall be averaged over the test period.

The impact of observed dry air temperature and relative humidity on combustion turbine performance will be corrected, for each Season, to the past five years average rated conditions experienced at the unit location measured at the date and time of MISO's seasonal coincident

peaks. Where inlet cooling is used to reduce turbine inlet air temperature, the temperature at the discharge of the Inlet coolers shall be the basis for air temperature correction.

J.5.5 Hydro (HD) and Pumped Storage (PS)

The test shall be at least one (1) continuous hour and data shall be averaged over the test period.

The GVTC established for hydroelectric plants shall recognize the head available considering environmental, operational, and regulatory restrictions and ambient conditions such as forecasted reservoir levels or water flow conditions. The test capability shall be corrected to historic median head conditions as specified below.

The seasonal historic median head shall be determined as the median of all head measurements from the most recent five (5) years up to the most recent fifteen (15) years. If 15 years of historic data is not available for this period when the 15-year time period is chosen, or is no longer relevant due to environmental, operational, regulatory or other restrictions, all available relevant data shall be used and accumulated until the 15-year requirement is met. The hours ending 1500, 1600, and 1700 EST apply to all days of the Summer (June, July, August), Fall (September, October, November), and Spring (March, April, May). The hours ending 0900, 1000, 1900, and 2000 EST apply to all days of the Winter (December, January, February).

Once the number of years and methodology is chosen and submitted as GVTC requirements, the same number of years must be submitted in future GVTC data collection.

Each hydro unit shall be verified individually.

The entire hydro plant shall be verified if the sum of individual unit capabilities is greater than the total plant capability.

MISO PowerGADS does not accept seasonal corrections for Hydro and Pumped Storage resources. If a Generation Operator (GO) elects to submit seasonal corrections they can use the Hydro and Pumped Storage GVTC Corrections template which can be found at https://www.misoenergy.org/planning/resource-adequacy/#nt=/planningdoctype:RA%20Guides%20and%20References/raguidetype:GVTC. If a GO elects to submit seasonal corrections, they must submit a test in MISO PowerGADS and

the Hydro and Pumped Storage GVTC Corrections template to the MISO Help Center help.MISOEnergy.org.

J.5.6 Diesel (DS)

The test shall be at least one (1) continuous hour and data shall be averaged over the test period.

No corrections apply to this unit type.

J.5.7 Electric Storage Resources (ESR)

This section is for all ESR except Pumped Storage. For pumped storage see J.5.5.

The test shall be at least one (1) continuous hour and data shall be averaged over the test period. The test shall be conducted at the discharge rate that would be expected if the ESR were dispatched for four (4) continuous hours. The test results must be submitted in the Module E Capacity Tracking (MECT) tool (Planning Resources > Non-GADS Resource Registration) using the Non-GADS Performance Template posted on the MISO Website.

J.5.8 General Requirements

If a generating unit has not been in operation for five years, then as many years as the unit has been in operation shall be used. The GVTC for new generating units will be corrected based on estimated average daily maximum circulating water temperature measured at the date and time of MISO's Peaks.

The unit shall be operated with the regularly available type and quality of fuel.

The Station Service shall be representative of the conditions expected to occur during MISO's coincident peaks.

For facilities consisting of multiple units, shared station power and process load served shall be allocated to the individual units to compute unit net capability.

J.6 Reporting

The following information shall be reported to MISO's PowerGADS as described in MISO's *Net Capability Verification Test User Manual*. Certain data will be reported or calculated for each of the 4 Seasons – summer, fall, winter and spring.

CARD	Must be "90"
Utility	Required

Unit	Required
Year	Required
Test Index	Must be a "1"
REVISIONCODE	Must be "0" for initial upload, "R" to Revise, or "D" to Delete
Corrected Net - Seasonal	Calculated by PowerGADS
Test Start Date	Required
Test End Date	Required
Gross MW	Required
Station Service	Required
Process Load Served	Required
Net Test Capability	Required, Gross MW – Station Service – Process Load Served
Reactive Generation MVAR	Optional
Total Power MVA	Calculated by PowerGADS if Reactive Generation MVAR entered
Power Factor	Calculated by PowerGADS if Reactive Generation MVAR entered
Dry Air Temperature Observed - Seasonal	Required for certain unit types
Dry Air Temperature Rated - Seasonal	Required for certain unit types
Air Temperature Correction	Required, may be zero
Relative Humidity Observed - Seasonal	Required for certain unit types
Relative Humidity Rated - Seasonal	Required for certain unit types
Relative Humidity Correction	Required, may be zero
Cooling Water Temperature Observed - Seasonal	Required for certain unit types
Cooling Water Temperature Rated - Seasonal	Required for certain unit types
Cooling Water Temperature Correction	Required, may be zero
STANDARD	Must be "MISO"

Appendix K – Resource Adequacy Timeline for activities for the Planning Year 2025-2026

Please check for the latest online version posted on the Resource Adequacy webpage of MISO's corporate website.

Date	Process and Notes	Responsible Entity	Tariff Reference
Sep 01, 2024	Start Cost of New Entry (CONE) calculation in coordination with IMM.	MISO/IMM	69A.8(a)(3)
Sep 09, 2024	MISO to publish historical monthly and seasonal Coincident Peak Load hours and LRZ seasonal coincident factors.	MISO	69A.1.1.(c)
Oct 01, 2024	Last day to submit outage exemption related resolution requests regarding Schedule 53 resources through the MISO Help Center.	Resource Owner	
Oct 01, 2024	MISO opens the new Planning Year in the MECT for all 4 Seasons. (1st Business Day - October)	MISO	
Oct 01, 2024	Transmission losses by Local Balancing Authority are posted by MISO. (1st Business Day - October)	MISO	69A.1.1(b)
Oct 15, 2024	MISO posts RA hours to be used for accreditation calculation	MISO	
Oct 31, 2024	Generation Verification Test Capacity (GVTC) due. Resource Owners submit operational data or real power test for September 1 - August 31 period.	Resource Owner	69A.3.1.a, b, & c, 69A.3.6
Oct 31, 2024	Populated Non-GADS Performance Templates due in MECT.	Resource Owner	69A.3.1.a(1)(d)
Oct 31, 2024	Generator availability data due in GADS for resources required to report for Q3. Resource Owners must ensure at least 36 months of data is provided.	Resource Owner	69A.3.1.a(1)(c)
Nov 01, 2024	Seasonal Coincident and Non-Coincident Peak Demand forecasts by LSE/EDC, monthly peak Demand, seasonal peak Demand and energy-for-load forecast values by LSE due. No action needed by Retail Choice LSEs.	LSE, EDC	69A.1.1(a)
Nov 01, 2024	Loss of Load Expectation study results published by MISO.	MISO	68A.2 68A.4 68A.5

Date	Process and Notes	Responsible Entity	Tariff Reference
Nov 07, 2024	MP must request an extension from within 5 business days after October 31 deadline.	Resource Owner	69A.3.1.a, b, & c, 69A.3.6
Nov 15, 2024	Review list of units with conditional Interconnection Service for results of annual study. Units may have NRIS/ERIS balance re-allocated.	MISO	
Dec 01, 2024	For individual States establishing their own seasonal PRM, submission of written letter by authorized State regulatory authority representative notifying MISO.	State Regulatory Authority	68A.1
Dec 15, 2024	RBDC opt out adder % posted on MISO website	MISO	69A.9.1 (l)
Dec 15, 2024	Initial UCAP/ISAC ratio, initial Seasonal Capacity accreditation values and validation files are published by MISO.Resources that do not meet the October 31 deadline will have their initial capacity accreditation calculated using estimated capacity submitted along with GVTC extension requests. MP may begin submitting resolution requests though the MISO Help Center.	MISO	
Dec 15, 2024	PLC submissions by EDC due. EDC will send the details of the PLCs to the respective LSEs and to MISO for review. The EDC-provided PLC data will be the default value for the LSE's Retail Choice Coincident Peak.	Retail Choice EDCs	69A.1.1(e)
Dec 15, 2024	Last day for MPs to submit to March Network & Commercial Model changes to qualify for ICAP Deferral.	Resource Owner	
Jan 15, 2025	LSE submit initial RBDC Opt Out Plan in MECT, including its RERRA contact	LSE	69A.9.1 (c)
Jan 15, 2025	Generation Verification Test Capacity (GVTC) due for generators that requested an extension.	Resource Owner	69A.3.1.a, b, & c, 69A.3.6
Jan 15, 2025	LSEs confirm the seasonal Retail Choice PLC in the MECT. LSEs should have all PLC questions resolved by this date. If an LSE desires a change in their PLC value, the appropriate EDC should be contacted directly.	LSEs, Retail Choice EDC	69A.1.1.1
Jan 15, 2025	Evidence for seasonal HUC/ZDC hedges due.	LSE	69A.7.7(b)

Date	Process and Notes	Responsible Entity	Tariff Reference
Jan 20,2025	MISO notifies RERRA its regulating LSE's initial plan for opting out RBDC	MISO	69A.9.1 (d)
Jan 31, 2025	Default technology-specific avoidable costs posted by the IMM. Resource owners may use the default costs in lieu of submitting facility specific operating costs for a facility specific Reference Level request. (59 days prior to deadline for offers)	IMM	64.1.4(f)(ii)
Jan 31, 2025	Generator availability data due in GADS for resources required to report for Q4.	Resource Owner	69A.3.1.a, b, & c, 69A.3.6
Feb 01, 2025	Last day to submit non-exemption related resolution requests on ISAC posted for Schedule 53 resources through the MISO Help Center.	Resource Owner	
`Feb 01, 2025	Existing Load Modifying Resource, Energy Efficiency, and External Resource registrations due for prompt Planning Year.	LMR/EE/ER Owner	
Feb 01, 2025	Loss of Load Expectation study begins for next Planning Year.	MISO	
Feb 01, 2025	Evidence of Demand Resource testing due. Last day to submit evidence. DR testing or performance must take place during the calendar year prior to the upcoming Planning Year.	DR Owner	69A.3.5
Feb 01, 2025	Written letter from officer of company stating intention to leverage DR testing deferral provisions due.	DR Owner	69A.3.5(l)
Feb 07, 2025	Last day to submit a Full Responsibility Transaction. (due the 5th business day of February)	LSE	
Feb 14, 2025	If utilizing FSRL, last day to submit request to IMM regarding Going-Forward Cost determination. Submit data for facility ZRC reference levels to IMM. (45 days prior to close of PRA offer deadline)	Generation Owner	64.1.4.f.iii.b
Feb 15, 2025	Final UCAP/ISAC ratio and SAC values for Schedule 53 resources will be posted on MECT. Schedule 53 resource owners can start confirming SAC and converting SAC into ZRCs.	MISO	
Feb 15, 2025	New Load Modifying Resource, Energy Efficiency Resource, and External Resource registrations must be submitted for approval to be considered for inclusion in seasonal FRAP or RBDC Opt Out.	LSE	69A.9(a)

Date	Process and Notes	Responsible Entity	Tariff Reference
Feb 15, 2025	LSEs submit request to revise seasonal Coincident Peak Demand forecast originally submitted on November 1. MISO will review and either approve or deny request.	LSE	
Feb 15, 2025	Written letter from officer of company stating intention to leverage ICAP Deferral provisions.	Resource Owner	69A.7.9(a)
Feb 17, 2025	Last day that RERRA notifies MISO if it denies any of the LSE's plan for opting out RBDC	RERRA	69A.9.1 (d)
Feb 28, 2025	Capacity accreditation updated for resources granted ICAP Deferral.	MISO	
Mar 01, 2025	Seasonal Generator Verification Test Capacity and generator availability data for new resources or resources with increased capacity due for prompt Planning Year.	Generation Owner	69A.3.1.a(d)
Mar 01, 2025	New Load Modifying Resource, Energy Efficiency Resource, and External Resource registrations must be submitted for approval in the MECT for the prompt Planning Year.	LMR/EE/ER Owner	69A.9(a)
Mar 01, 2025	Deadline to satisfy credit requirements for DRs opting out of or deferring testing. Credit posting only required if DR doesn't have regulatory restrictions or contractual obligations that preclude testing.	DR Owner	69A.3.5 (j)(2)&(l)
Mar 01, 2025	MISO to complete its seasonal Coincident Peak Demand forecast review process.	MISO	69A.1.1(c)
Mar 01, 2025	Satisfy credit posting requirement for seasonal capacity accreditation issued from resources granted ICAP Deferral.	Resource Owner	69A.7.9(b)
Mar 01, 2025	Resource Owners submit Attachment Y requests for units scheduled for retirement/suspension between 3/30 and 5/31 to receive exemption from physical withholding.	Resource Owner	38.2.7.a.(i)
Mar 03, 2025	Publish seasonal Sub Regional Import Constraint (SRIC) and seasonal Sub Regional Export Constraint (SREC) for each Sub Regional Resource Zone (SRRZ) no later than first business day in March.	MISO	68A.3.1
Mar 10, 2025	Finalize and submit HUC registrations in the MECT.	LSE	
Mar 11, 2025	Seasonal Fixed Resource Adequacy Plan due by LSE. (7th Business Day of March)	LSE	69A.9(a)
Mar 11, 2025	LSE confirms its RBDC Opt Out Plan in MECT (7th Business Day of March)	LSE	69A.9.1(c)
Mar 14, 2025	Last day to notify IMM of deliverable resources requesting to be excluded from offering into seasonal PRAs or included in a FRAP or RBDC Opt Out.	Generation Owner	
Mar 15, 2025	Fixed Resource Adequacy and RBDC Opt Out Plan review completed by MISO. The LSE will have until the auction	MISO(LSE)	69A.9(a) 69A.9.1(c)

Date	Process and Notes	Responsible Entity	Tariff Reference
	offer window opens to remedy any deficiencies in their FRAP or RBDC Opt Out.		
Mar 19, 2025	Final date to update seasonal CIL and CEL values for each LRZ prior to the Planning Resource Auction. Changes due to firm capacity commitments from MISO resources to neighboring regions established prior to the PRA.	MISO	68A.4
Mar 19, 2025	CEL determined for each ERZ. Equal to the ZRC quantity of the External Resources registered to participate in the PRA. (8th business day in March prior to the last business day)	MISO	68A.4
Mar 19, 2025	Final posting by MISO of preliminary seasonal PRA data, reflective of updated information from LSEs, Resource Owners and PJM auction results. Coincides with seasonal CIL/CEL calculations.	MISO	
Mar 27, 2025	Provide Facility Specific Resource Level(s) to MPs 5 days prior to the close of the PRA offer window.	IMM	64.1.4.f
Mar 25, 2025	Final day for confirming/converting SAC in MECT.	Resource Owner	
Mar 26, 2025	Planning Resource Auction offer window is opened for all Seasons. Auction Offer window is opened at 8:00 AM EPT, 3 business days prior to the last business day in March.	MISO	69A.7.1(a)
Mar 31, 2025	Planning Resource Auction offer window is closed for all Seasons. Auction Offer window is closed at 6:00 PM EPT on the last business day of March.	MISO	69A.7.1(a)
Apr 01, 2025	Iterations of seasonal auction runs with adjusted seasonal CILs and CELs may be required to ensure that a network loading is not violated. Additionally, MISO will work with the IMM to evaluate potential withholding. The reference levels are used to determine financial withholding. The mitigation of financial withholding can be expected to reduce the Auction Clearing Price. (First 20 Business Days of April)	MISO/IMM*	69A.7
Apr 28, 2025	Seasonal Planning Resource Auctions results posted. (20th Business Day of April)	MISO	69A.7
Apr 30, 2025	Generator availability data due in GADS for resources required to report for Q1.	Resource Owner	69A.3.1.a, b, & c, 69A.3.6
May 01, 2025	MISO to assess seasonal Capacity Deficiency Charges for applicable LSEs.	MISO	69A.10(a)

Date	Process and Notes	Responsible Entity	Tariff Reference
May 8, 2025	MISO sends Capacity Deficiency Charges to applicable LSEs 5 business days after assessment.	MISO	
May 19, 2025	Capacity Deficiency Charge payments distributed to MPs. Payment made within 7 business days of receipt.	MISO	
May 28, 2025	Publish details of the seasonal ZRC offers submitted in the PRA. Market Participant IDs are not revealed. (One month after PRA)	MISO	69A.7.4
May 28, 2025	MISO publishes cleared LMRs to DSRI. MISO publishes must offer performance requirements in the applicable Operations tool.	MISO	
May 30, 2025	Information due to satisfy ICAP Deferral must be submitted to MISO to avoid ICAP Deferral Non-Compliance Charge for Summer Season. (Last business day of Planning Year)	LSE	69A.7.9(a) (2)
May 30, 2025	Information due to satisfy DR Deferral Notice must be submitted to MISO in order to release credit requirements and avoid LMP performance penalties.	DR Owner	69A.3.5
Jun 01, 2025	Summer Season in new Planning Year starts.	All	69A.7
Jun 01, 2025	Daily settlements for the Summer Season starts.	All	
July 31, 2025	Generator availability data due in GADS for resources required to report for Q2.	Resource Owner	69A.3.1.a, b, & c, 69A.3.6
August 29, 2025	Information due to satisfy ICAP Deferral must be submitted to MISO to avoid ICAP Deferral Non-Compliance Charge for Fall Season. (Last business day)	LSE	69A.7.9(a) (2)
Sep 01, 2025	Fall Season in new Planning Year starts.	All	69A.7
Sep 01, 2025	Daily settlements for the Fall Season starts.	All	
November 26, 2025	Information due to satisfy ICAP Deferral must be submitted to MISO to avoid ICAP Deferral Non-Compliance Charge for Winter Season. (Last business day)	LSE	69A.7.9(a) (2)
Dec 01, 2025	Winter Season in new Planning Year starts.	All	69A.7
Dec 01, 2025	Daily settlements for the Winter starts.	All	

Date	Process and Notes	Responsible Entity	Tariff Reference
February 27, 2026	Information due to satisfy ICAP Deferral must be submitted to MISO to avoid ICAP Deferral Non-Compliance Charge for Spring Season. (Last business day)	LSE	69A.7.9(a) (2)
Mar 01, 2026	Spring Season in new Planning Year starts.	All	69A.7
Mar 01, 2026	Daily settlements for the Spring Season starts.	All	

Appendix L – Transmission Losses Calculation

The Transmission Provider will calculate the seasonal LBA Transmission loss percentages using the process described as follows:

1. The Transmission Provider's State Estimator calculates transmission losses (MW) as part of the solution output process every five (5) minutes.
2. The transmission losses (MW) are computed on all transmission lines and transformers by summing up real power at both ends for each transmission element (retaining the convention for flow direction) or as the difference in real power (without the sign convention for flow direction) for each State Estimator solution.
3. The individual transmission losses (MW) for each element are summed to a total transmission value for each Local Balancing Authority (LBA) level.
4. These LBA transmission loss values are then integrated across each hour to calculate an hourly transmission loss value (MW) for each LBA.
5. The total transmission loss value (MW) for each LBA will be the hourly integrated transmission losses value (MW) for the hour of the Transmission Provider's system peak during each of the four previous Seasons.
6. The LBA transmission loss percentages are calculated as the total LBA transmission losses divided by the total LBA load, at each seasonal MISO peak hour.

The seasonal LBA transmission loss percentage calculated by the Transmission Provider will apply to the LSE's applicable seasonal LBA Coincident Peak Demand forecast to determine the LSE transmission losses for the calculation of the seasonal Initial PRMR. The LBA transmission loss percentage calculated by the Transmission Provider coincident with each LRZ’s seasonal Peak Demand forecast will determine the LSE transmission losses for the calculation of LRR. Both the MISO and Zonal Transmission Losses will be posted on the MISO public website by November 1 before the upcoming Planning Year.

Initial PRMR met with Behind-the-Meter-Generation Resources that are interconnected to the Transmission System shall be treated like other Resources with respect to transmission losses. Initial PRMR met with Behind-the-Meter-Generation Resources that are not interconnected to the Transmission System shall be adjusted to account for serving load without incurring transmission losses by grossing up the MW quantity of such resources by (1.0 + the appropriate LBA transmission loss percentage).

APPENDIX M: PLANNING RESOURCE AUCTION FORMULATION WITH RELIABILITY-BASED DEMAND CURVES

Disclaimer

This document is prepared for informational purposes only and is intended to help the user understand how the MISO Tariff provisions relating to Resource Adequacy Requirements and Reliability-Based Demand Curves are implemented in MISO's Planning Resource Auction (PRA). MISO may revise or terminate this document at any time at its discretion without notice. However, every effort will be made by MISO to update this document and inform its users of changes as soon as practicable. Nevertheless, it is the user's responsibility to ensure you are using the most recent version posted on the MISO website. In the event of a conflict between this document and the Tariff, the Tariff will control, and nothing in this document shall be interpreted to contradict, amend or supersede the Tariff. MISO owns the intellectual property of this document and content.

Purpose of this document

MISO's Resource Adequacy construct provides LSEs in the MISO footprint an ability to procure planning resources through a PRA for each Season within the Planning Year (PY). A Linear Programming (LP) based optimization tool has been developed to clear the auction and calculate Auction Clearing Prices (ACP). This document provides a detailed mathematical representation of the constrained optimization formulation that is used for clearing the seasonal PRA and explains how the zonal Auction Clearing Prices are calculated for each Season within the PY.

1 Overview of Auction Clearing Processes

MISO is introducing sloped demand curves in its Resource Adequacy construct through the implementation of Reliability-Based Demand Curve (RBDC) in the 2025 PRA. Specifically, MISO utilizes distinct sloped demand curves at both the systemwide and sub-regional levels: one systemwide RBDC and separate subregional RBDCs for the North/Central (N/C) and South subregions (also called planning areas). The systemwide RBDC addresses overall reliability needs across the entire system, while the subregional RBDCs capture additional reliability requirements specific to each subregion. As a result, for each season, MISO will utilize one systemwide RBDC and two sub-regional RBDCs in the PRA, totaling twelve RBDCs over the course of a Planning Year.

A subregional RBDC acknowledges the specific reliability needs of each sub-region. It is crucial to provide a price signal that reflects this regional diversity to promote efficient capacity pricing, resource planning, and grid reliability across MISO. Since MISO's footprint is divided into two subregions, each subregion will have two obligations to meet for resource adequacy: one from its share of the systemwide RBDC and the other from its own subregional RBDC. The share of systemwide RBDC is the systemwide RBDC weighted by the coincident peak demand share (with transmission losses) of the subregion. To ensure resource adequacy, the higher of these two obligations should be prioritized; meeting the higher obligation will automatically satisfy the lower one. The method for PRA clearing and pricing is outlined below.

Step 1 (RBDC identification): For each subregion, identify the RBDC curve between (i) share-of-systemwide RBDC and (ii) subregional RBDC that produces higher MW obligation in the neighborhood of the intersection of supply and demand curves.

Step 2 (Clearing and pricing): Use specific RBDCs identified in step 1 for each subregion and solve the clearing and pricing problem.

This solution methodology is summarized in **Error! Reference source not found.**.

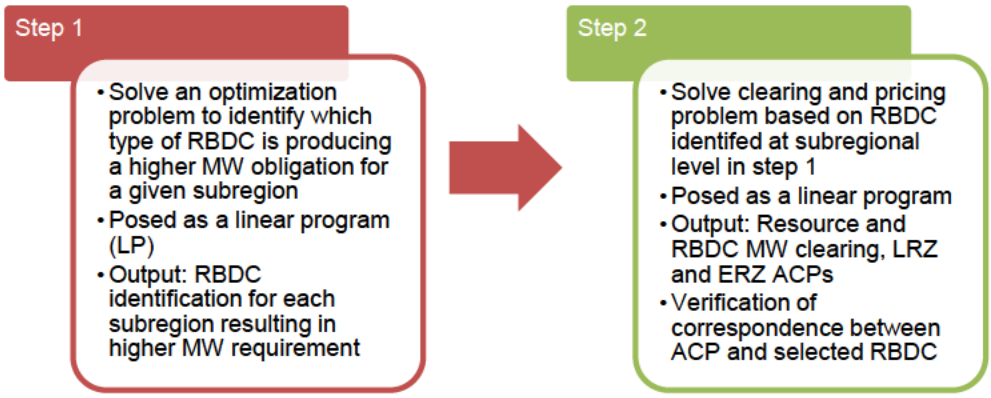


Figure 1. Overview of solution methodology

2 Preliminaries

This section defines the notation used in the optimization problem. In cases of ambiguity, we use the superscript SR to denote parameters or decision variables associated with subregional RBDC clearing, while the superscript SYS is used in reference to systemwide RBDC clearing. The optimization variables are in orange font.

2.1 Sets

Set DC = {Systemwide RBDC (SYS-RBDC), North/Central subregion RBDC (NC-RBDC), South subregion RBDC (S-RBDC)}

Set R = {North/Central subregion (NC), South subregion (S)}

Set Z = {All local resource zones (LRZs) in the transmission planning area}

Set Z_r = {All local resource zones (LRZs) in the subregion $r \in R$}

Set Z_n = {All North/Central subregion LRZs (LRZ 1 through 7)}

Set Z_s = {All South subregion LRZs (LRZ 8 through 10)}

Set E = {All external resource zones (ERZs) participating in the PRA}

Set F = {All resource offers in the system including LRZs and ERZs}

Set G = {All resources in LRZs}

Set G_k = {All resources in LRZ k}

Set G_r = {All resources in the LRZs within subregion $r \in R$}

Set H = {All resources in external zones (including dual connected external zones)}

Set H_e = {All resources in external zone *e*}

Set J_{dc} = {All demand segments in RBDC $dc \in DC$}

Set J_r = {All demand segments in subregional RBDC for subregion $r \in R$}

Set MC = {All resources which are part of fixed resource adequacy plans (FRAPs), or self-scheduled resources ($0 offer price), or resources covered by RBDC Opt Out}

2.2 Parameters

The following parameters are used to set up the constrained optimization problem for the PRA:

$INITIALPRMR_k$	Initial Planning Reserve Margin Requirement (PRMR) for LRZ *k*. Initial PRMR refers to PRMR for achieving the seasonal systemwide LOLE target (1-day-in-10 for Summer and 1-day-in-100 for other seasons)
$CPDF_k$	Coincident Peak Demand Forecast (CPDF) for LRZ *k*
LCR_k	Local Clearing Requirement for LRZ *k*
CIL_k	Capacity Import Limit for LRZ *k*
CEL_k	Capacity Export Limit for LRZ *k*
CEL_e	Capacity Export Limit for external zone *e*
$SREC_r$	Subregional export constraint (SREC) for subregion $r \in R$
$SRIC_r$	Subregional import constraint (SRIC) for subregion $r \in R$
$OFFERPRICE_i$	The offer price for resource *i*[3]
$OFFERMW_i$	Offered MW value for resource *i*
$SF_{r,e}$	Shift Factor ∈[0, 1] to subregion *r* for resources in external zone *e*[4]

ACP_k	Auction Clearing Price for Zone k
$CONE_k$	Annualized cost of new entry (CONE) for LRZ *k*
$CONE_n$	Average annualized CONE for LRZs in the North/Central subregion
$CONE_s$	Average annualized CONE for LRZs in the South subregion
$CONE_{SYS}$	Average annualized CONE for all LRZs in MISO
$SEASONALCONE_k$	Annualized CONE for LRZ *k* divided by number of days in the season
$SEASONALCONE_e$	For dual connected ERZ e: maximum annualized CONE of all LRZ*s* divided by number of days in the season. For ERZ e connected to a single subregion: maximum annualized CONE of all LRZ*s* in that subregion divided by number of days in the season.
$DAILYCONE_k$	Annualized CONE for LRZ *k* divided by number of days in the planning year
$RBDCPRICE_{j,dc}$	RBDC Price ($/UCAP MW-day) for demand curve segment $j \in J_{dc}$ for demand curve version $dc \in DC$
$RBDCSTEP_{j,dc}$	RBDC Step Size (UCAP MW) for demand curve segment $j \in J_{dc}$ for demand curve version $dc \in DC$
u_r	Binary parameter for MISO subregion $r \in R$ indicating the RBDC selected for step 2 of the solution methodology: 0 refers to share-of-systemwide RBDC, and 1 refers to the subregional RBDC
α_k^{SYS}	CPDF share of LRZ *k* with respect to all the LRZs in the system given by the following equation: $$\alpha_k^{SYS} \overset{def}{=} \frac{CPDF_k}{\sum_{k \in Z} CPDF_k} \in [0,1]$$
α_r	CPDF share of region $r \in R$, given by: $$\alpha_r \overset{def}{=} \sum_{k \in Z_r} \alpha_k \in [0,1]$$
α_k^r	CPDF share of LRZ *k* in subregion $r \in R$ with respect to all the LRZs in that subregion, given by:

$$\alpha_k^r \overset{def}{=} \frac{\alpha_k}{\alpha_r} \in [0,1]$$

2.3 Decision Variables

The optimization variables for the two linear programs are as follows (**all variables are non-negative**):

$clearedMW_i^{SYS}$	Cleared MW value of offer *i* to meet systemwide RBDC demand in step 1
$clearedMW_i^{SR}$	Cleared MW value of offer *i* to meet systemwide RBDC demand in step 1
$clearedMW_i$	Cleared MW value of offer *i* to meet selected RBDC demand in step 2
$clearedDemand_{j,r}^{SYS}$	Cleared MW value of systemwide RBDC segment *j* for subregion $r \in R$ [5]
$clearedDemand_{j,r}^{SR}$	Cleared MW value of subregional RBDC segment *j* for subregion $r \in R$
S_k^{SYS}	MW amount by which LRZ *k* is short of its local clearing requirement (LCR) or initial PRMR - CIL while meeting systemwide RBDC demand in step 1
S_k^{SR}	MW amount by which LRZ *k* is short of its local clearing requirement (LCR) or initial PRMR - CIL while meeting subregional RBDC demand in step 1
S_k	MW amount by which LRZ *k* is short of its local clearing requirement (LCR) or initial PRMR - CIL in step 2

3 Step 1: RBDC identification

The objective of the RBDC identification procedure is to determine which RBDC between share-of-systemwide RBDC and subregional RBDC is producing a higher MW requirement for each subregion. The requirements are determined through a solution to a linear program.

The identification of the RBDC producing a higher requirement is challenging, a priori. This difficulty is illustrated via the two plots on the first row of **Error! Reference source not found.** c orresponding to the summer season in the MISO N/C region and MISO South region, respectively: on the left, the subregional RBDC will always result in a higher MW requirement as compared to the share-of-systemwide RBDC for any clearing price point. However, on the right, both RBDCs are intertwined and depending on supply and demand curve intersection either systemwide or subregional RBDC could result in a higher MW requirement. This systemwide

and the subregional RBDC interaction increases the complexity of the PRA clearing process. To address this, an LP based optimization approach is utilized for the determination of the correct RBDC (higher MW requirement) for each subregion in a given season; this selected RBDC is used for the optimization in step 2.

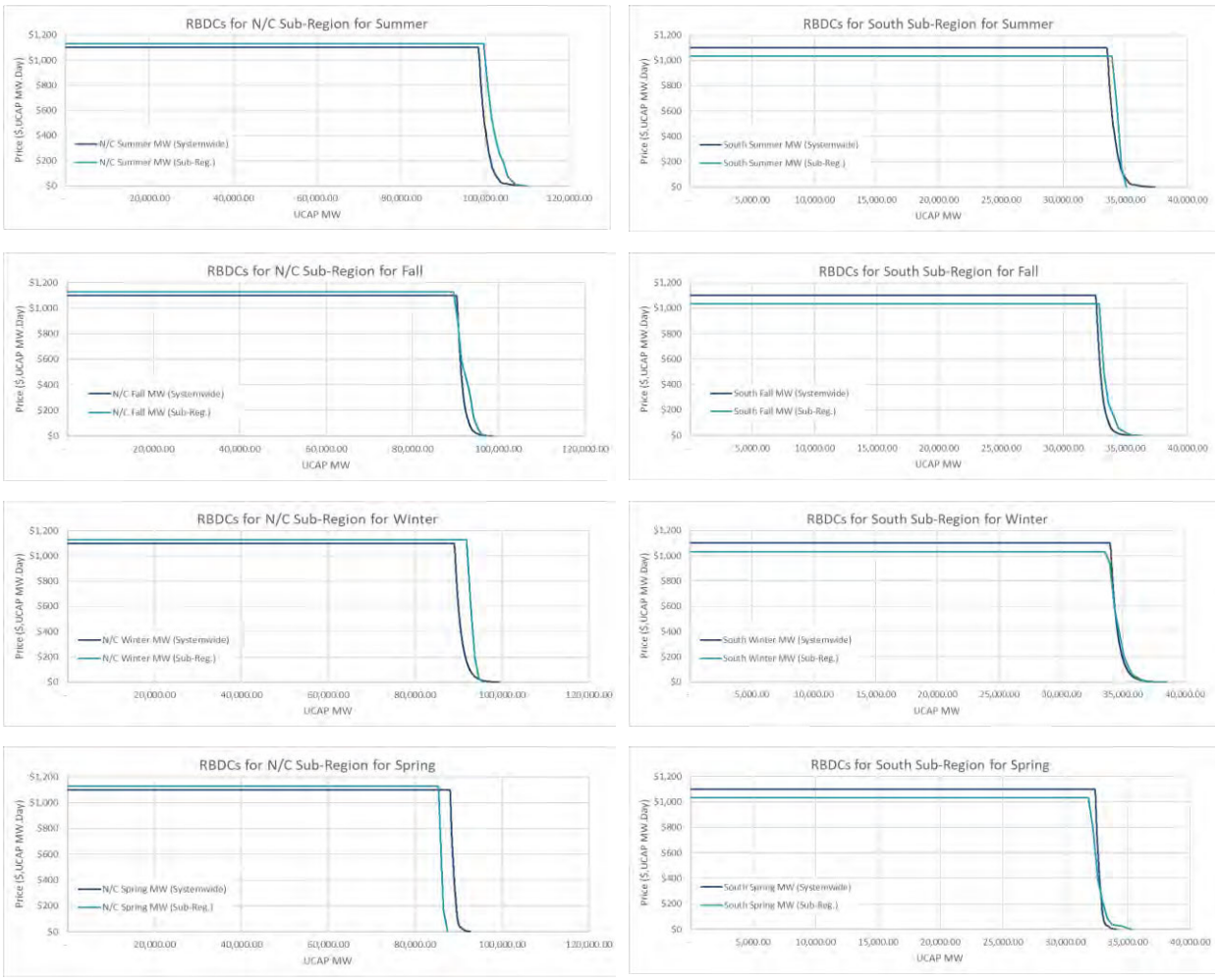


Figure 2. Indicative seasonal RBDC curves for N/C and South subregions, also showing the load-share-based projection of systemwide RBDC on to the sub-region.

3.1 Step 1 Formulation

The optimization problem for the RBDC identification step is posed as a linear program with the objective to minimize the cost of balancing capacity & demand for two scenarios: (i) demand is from share-of-systemwide RBDC in each subregion, and (ii) demand is from subregional RBDC

in each subregion. In this formulation, these two scenarios are enforced independently. Subregional power balancing constraints and zonal clearing constraints are also enforced independently for each scenario.

After solving the LP, the demand cleared on the basis of share-of-systemwide RBDC is compared with the demand cleared on the basis of the subregional RBDC clearing for both N/C and south subregions: for each subregion, the type of RBDC (share-of-systemwide RBDC or subregional RBDC) which produces the higher MW requirement is identified and selected for use in step 2 of the clearing process. The optimization formulation for step 1 is presented in the following.

3.1.1 Objective Function

The linear minimization objective is as follows:

$$\text{Minimize } f \stackrel{\text{def}}{=} SC - (SB + RB) + \Lambda, \tag{3.1.a}$$

with SC referring to the supply cost which is the area under the offer curve, SB and RB referring to the reliability benefits from the systemwide and subregional RBDCs which are the areas under the systemwide RBDC and subregional RBDCs, respectively, and Λ as the shortage penalty for zonal LCR shortage or initial PRMR shortage beyond the capacity import limit (CIL) of the zone. These terms are expressed as follows:

$$SC \stackrel{\text{def}}{=} \sum_{i \in F} OFFERPRICE_i \times (clearedMW_i^{SYS} + clearedMW_i^{SR}) \tag{3.1.b}$$

$$SB \stackrel{\text{def}}{=} \sum_{j \in J_{SYS-RBDC}} \sum_{r \in R} \alpha_r \times RBDCPRICE_j \times clearedDemand_{j,r}^{SYS} \tag{3.1.c}$$

$$RB \stackrel{\text{def}}{=} \sum_{r \in R} \sum_{j \in J_r} RBDCPRICE_j \times clearedDemand_{j,r}^{SR} \tag{3.1.d}$$

$$\Lambda \stackrel{\text{def}}{=} \sum_{k \in Z} SEASONALCONE_k \times (S_k^{SYS} + S_k^{SR}) \tag{3.1.e}$$

3.1.2 Constraints

The optimization constraints are based on system, subregional, and zonal balancing requirements, in addition to bounds on resource and segment clearing. Note that all decision variables are restricted to be in the domain of non-negative real values.

3.1.2.1 Resource Offer Bounds

Resource clearing should not exceed the MWs offered by the resources

$$clearedMW_i^{SYS} \leq OFFERMW_i, \quad \forall i \in F \tag{3.2.a}$$

$$clearedMW_i^{SR} \leq OFFERMW_i, \quad \forall i \in F \tag{3.2.b}$$

3.1.2.2 RBDC segment bounds

Price sensitive demand, characterized by different RBDCs, has limits based on the segments of the RBDC; MWs cleared in RBDC segments should not exceed the RBDC segment limits:

$$clearedDemand_{j,r}^{SYS} \leq RBDCSTEP_j, \quad \forall j \in J_{SYS-RBDC}, \quad \forall r \in R \tag{3.3.a}$$

$$clearedDemand_{j,r}^{SR} \leq RBDCSTEP_j, \quad \forall j \in J_r, \quad \forall r \in R \tag{3.3.b}$$

3.1.2.3 Power balance constraints

Systemwide supply-demand balance constraints. To properly value the reliability given the clearing outcome, the supply-demand balance equations enforce the condition that cleared supply is greater than or equal to cleared demand.

In step 1, the supply-demand balance must hold for both the system and subregional RBDC curves: the cleared quantity of demand from each RBDC curve must be met by corresponding supply-side variables.

$$\sum_{i \in F} clearedMW_i^{SYS} \geq \sum_{j \in J_{SYS-RBDC}} \sum_{r \in R} \alpha_r \times clearedDemand_{j,r}^{SYS} \tag{3.4.a}$$

$$\sum_{i \in F} clearedMW_i^{SR} \geq \sum_{r \in R} \sum_{j \in J_r} clearedDemand_{j,r}^{SR} \tag{3.4.b}$$

Subregional supply-demand balance constraints. These constraints ensure that the difference between the cleared supply available within a subregion and the cleared demand associated with the subregion is within the subregional import and export limits (SRIC and SREC, respectively). In step 1, the constraints are imposed for clearing associated with both systemwide and subregional RBDCs as follows, respectively:

$$-SRIC_r \leq \sum_{i \in G_r} clearedMW_i^{SYS} + \sum_{e \in E} SF_{r,e} \times \sum_{k \in H_e} clearedMW_k^{SYS} - \sum_{j \in J_{SYS-RBDC}} \alpha_r \times clearedDemand_{j,r}^{SYS} \leq SREC_r, \quad \forall r \in R \tag{3.5.a}$$

$$-SRIC_r \leq \sum_{i \in G_r} clearedMW_i^{SR} + \sum_{e \in E} SF_{r,e} \times \sum_{k \in H_e} clearedMW_k^{SR} - \sum_{j \in J_r} clearedDemand_{j,r}^{SR} \leq SREC_r, \quad \forall r \in R \tag{3.5.b}$$

3.1.2.4 Zonal Clearing Constraints

Local Clearing Requirement (LCR) and Capacity Import Limit (CIL) constraints ensure that the quantity of cleared supply in the zone must exceed the minimum of the LCR and the share of Initial PRMR that cannot be met by imports. If the quantity of cleared supply falls short of either of these limits, the shortfall variable is penalized at the zone's seasonal CONE value in the objective function (3.1.a). In Step 1, the LCR and CIL are enforced for both the systemwide and subregional RBDC clearing outcomes. The LCR constraints are as follows:

$$\sum_{i \in G_k} clearedMW_i^{SYS} + S_k^{SYS} \geq LCR_k, \quad \forall k \in Z \tag{3.6.a}$$

$$\sum_{i \in G_k} clearedMW_i^{SR} + S_k^{SR} \geq LCR_k, \quad \forall k \in Z \tag{3.6.b}$$

The quantity of imports in the zone to meet initial PRMR requirements must be below CIL. Only the tighter of the LCR and CIL constraints will bind, so we can use the same shortage variables for both LCR and CIL constraints. The CIL constraints are as follows:

$$INITIALPRMR_k - \sum_{i \in G_k} clearedMW_i^{SYS} - S_k^{SYS} \leq CIL_k, \quad \forall k \in Z \tag{3.7.a}$$

$$INITIALPRMR_k - \sum_{i \in G_k} clearedMW_i^{SR} - S_k^{SR} \leq CIL_k, \quad \forall k \in Z \tag{3.7.b}$$

Capacity Export Limit (CEL) constraints ensure that the quantity of exports for the zone does not exceed the available transfer capabilities (CEL). The exports are the difference between the cleared supply in the LRZ and the load obligations of the LRZ. The load requirement for an LRZ is calculated based on the CPDF share of the LRZ with respect to the cleared demand in the subregion. Consequently, the LRZ obligations based on systemwide RBDC clearing and subregional RBDC clearing are given by, respectively,

$$LRZReq_k^{SYS} = \sum_{j \in J_{SYS-RBDC}} \alpha_k^{SYS} \times clearedDemand_{j,r}^{SYS}, \quad \forall k \in Z_r, \forall r \in R \tag{3.8.a}$$

$$LRZReq_k^{SR} = \sum_{j \in J_r} \alpha_k^{r} \times clearedDemand_{j,r}^{SR}, \quad \forall k \in Z_r, \forall r \in R \tag{3.8.b}$$

The CEL constraints for each LRZ corresponding to the systemwide RBDC and the subregional RBDCs are given by, respectively,

$$\sum_{i \in G_k} clearedMW_i^{SYS} - LRZReq_k^{SYS} \leq CEL_k, \quad \forall k \in Z \tag{3.9.a}$$

$$\sum_{i \in G_k} clearedMW_i^{SR} - LRZReq_k^{SR} \leq CEL_k, \quad \forall k \in Z \tag{3.9.b}$$

Since ERZs have no load obligations, their CEL constraints for systemwide RBDC and subregional RBDCs are given by, respectively,

$$\sum_{i \in H_e} clearedMW_i^{SYS} \leq CEL_e, \quad \forall e \in E \tag{3.9.c}$$

$$\sum_{i \in H_e} clearedMW_i^{SR} \leq CEL_e, \quad \forall e \in E \tag{3.9.d}$$

4 Step 2: Clearing and Pricing

Following step 1: RBDC identification, the effective RBDCs for each subregion are established. In step 2, these identified RBDCs are used to determine resource and RBDC MW clearing along with the Auction Clearing Prices (ACPs). This clearing and pricing optimization problem is an LP problem.

In the social welfare optimization problem in step 2, for each subregion, we select the RBDC (between share-of-systemwide RBDC and subregional RBDC) that resulted in a higher requirement in that subregion. This selection is done via parameter u_r: for a given subregion $r \in R$, the parameter u_r is a binary parameter which is determined based on the clearing results of step 1. Parameter u_r is set to 0 if share-of-systemwide RBDC resulted in a higher clearing in step 1 (i.e., share-of-systemwide RBDC is selected for step 2), while it is set to 1 if the subregional RBDC resulted in a higher clearing in step 1 (i.e., subregional RBDC selected for step 2). The parameter selection for each subregion is given by the following equation:

$$u_r = 1\left(\left\{\sum_{k\in Z_r} LRZReq_k^{SYS} \leq \sum_{k\in Z_r} LRZReq_k^{SR}\right\}\right), \qquad \forall r \in R, \tag{4.1}$$

where 1 is the indicator function[6], and the LRZ clearing requirements are from step 1 as defined in (3.8).

4.1 Step 2: Formulation

Since we are selecting the RBDCs using the parameter u_r, step 2 does not require separate supply variables or constraint equations to distinguish between systemwide RBDC and subregional RBDCs. The details of the LP formulation for the clearing-and-pricing step 2 are as follows.

4.1.1 Objective Function

The linear minimization objective is given by the following equations, with the same terminology as defined in Section 3:

$$\text{Minimize } f \stackrel{\text{def}}{=} SC - (SB + RB) + \Lambda, \tag{4.2.a}$$

$$SC \stackrel{\text{def}}{=} \sum_{i\in F} OFFERPRICE_i \times clearedMW_i \tag{4.2.b}$$

$$SB \stackrel{\text{def}}{=} \sum_{j\in J_{SYS-RBDC}} \sum_{r\in R} (1-u_r) \times \alpha_r \times RBDCPRICE_j \times clearedDemand_{j,r}^{SYS} \tag{4.2.c}$$

$$RB \stackrel{\text{def}}{=} \sum_{r\in R} \sum_{j\in J_r} u_r \times RBDCPRICE_j \times clearedDemand_{j,r}^{SR} \tag{4.2.d}$$

$$\Lambda \stackrel{\text{def}}{=} \sum_{k\in Z} SEASONALCONE_k \times S_k \tag{4.2.e}$$

4.1.2 Constraints

In step 2, the power balancing constraints and the segment bounds are imposed for the selected RBDC using the parameter u_r. This subsection provides expression for the constraints in the LP.

4.1.2.1 Resource Offer Bounds

Resource clearing should not exceed the MWs offered by the resources

$$clearedMW_i \leq OFFERMW_i, \qquad \forall i \in F \tag{4.3}$$

4.1.2.2 RBDC segment bounds

MWs cleared in RBDC segments should not exceed the RBDC segment limits:

$$clearedDemand_{j,r}^{SYS} \leq (1-u_r) \times RBDCSTEP_j, \ \forall j \in J_{SYS-RBDC}, \qquad \forall r \in R \tag{4.4.a}$$

$$clearedDemand_{j,r}^{SR} \leq u_r \times RBDCSTEP_j, \qquad \forall j \in J_r, \qquad \forall r \in R \tag{4.4.b}$$

The multiplication involving the parameter u_r in the above equation ensures that the segment-wise clearing variables are allowed to take non-zero values only for the selected RBDC; the segment-wise clearing variables will be zero for the non-selected RBDC.

4.1.2.3 Power balance constraints

The system power balance constraint is represented below: the cleared systemwide supply should exceed the total system cleared demand from the selected RBDCs.

$$\sum_{i \in F} clearedMW_i \geq \sum_{r \in R} \sum_{j \in J_r} u_r \times clearedDemand_{j,r}^{SR} + \sum_{r \in R} \sum_{j \in J_{SYS-RBDC}} (1-u_r) \times \alpha_r \times clearedDemand_{j,r}^{SYS} \tag{4.5}$$

The subregional power balancing constraints ensure that the difference between the selected RBDC cleared demand and subregion cleared supply, including external resources clearing for the subregion, respects the subregional import and export constraints, as follows:

$$-SRIC_r \leq \sum_{i \in G_r} clearedMW_i + \sum_{e \in E} SF_{r,e} \times \sum_{k \in H_e} clearedMW_k - \sum_{j \in J_r} u_r \times clearedDemand_{j,r}^{SR} - \sum_{j \in J_{SYS-RBDC}} (1-u_r) \times \alpha_r \times clearedDemand_{j,r}^{SYS} \leq SREC_r, \qquad \forall r \in R \tag{4.6}$$

4.1.2.4 Zonal Clearing Constraints

The LCR and CIL are requirements that need to be met with local resources or penalized in cases of shortage. These constraints are represented as follows, respectively,

$$\sum_{i \in G_k} clearedMW_i + S_k \geq LCR_k, \ \forall k \in Z \tag{4.7}$$

$$INITIALPRMR_k - \sum_{i \in G_k} clearedMW_i - S_k \leq CIL_k, \quad \forall k \in Z \tag{4.8}$$

The CEL constraints are imposed with respect to the load obligation for each LRZ. The load obligation for LRZs is expressed as the zonal CPDF share of the cleared demand from the selected RBDC. This is given by,

$$LRZReq_k = \sum_{j \in J_{SYS-RBDC}} (1 - u_r) \times \alpha_k^{SYS} \times clearedDemand_{j,r}^{SYS} + \sum_{j \in J_r} u_r \times \alpha_k^r \times clearedDemand_{j,r}^{SR}, \quad \forall k \in Z_r, \forall r \in R \tag{4.9}$$

The difference between the zonal cleared supply and the LRZ load requirement should be below CEL:

$$\sum_{i \in G_k} clearedMW_i - LRZReq_k \leq CEL_k, \quad \forall k \in Z \tag{4.10.a}$$

Since ERZs do not have load obligations, their CEL constraints are given by:

$$\sum_{i \in H_e} clearedMW_i \leq CEL_e, \quad \forall e \in E \tag{4.10.b}$$

4.2 Verification of selected RBDC for Step 2

For a given subregion, if both the share-of-systemwide RBDC and the subregional RBDC are intertwined near the intersection of the supply and demand curves, then the RBDC producing higher requirement may be inconsistent between step 1 and step 2. Therefore, additional verification is performed to ensure that the curve selected for step 2 results in an appropriate requirement. This verification process is described below.

Verification step 1: Determine the subregional clearing price for subregion $r \in R$ as the sum of the shadow prices corresponding to the system and subregional power balancing constraints, i.e., the sum of the shadow prices (which are the dual variables) for the constraints (4.5) and (4.6).

Verification step 2: For the subregional clearing price calculated in verification step 1, determine the associated UCAP MW for the share-of-systemwide RBDC and the subregional RBDC for each subregion *r*. Note the RBDC that results in the higher requirement.

Verification step 3: For a given subregion, if the RBDC with the higher UCAP MW as determined in verification step 2 matches with the RBDC selected via the binary parameter u_r (0 implies selection of share-of-systemwide RBDC and 1 implies selection of subregional RBDC), then the PRA clearing solution is valid and we can proceed with the computation of clearing prices and obligations for the market participants.

If the verification fails for a given subregion, then this failure implies that the RBDC with the higher UCAP MW as determined in verification step 2 is different from the type of RBDC (share of systemwide or subregional) selected via the parameter u_r; hence, the PRA clearing solution is not valid. In such a case, the value of the parameter u_r for the subregion is switched to its complement (0 to 1, or 1 to 0), and step 2 of the PRA clearing process is solved again with this updated parameter.

4.3 Auction clearing Price calculations

Following the PRA clearing solution obtained in the step 2 optimization problem, the clearing prices are calculated for every LRZ and ERZ. This section describes the methodology for computing the auction clearing price (ACP).

4.3.1 ACP determination

The initial auction clearing price is calculated using the shadow prices (SP) of the system, subregional, and zonal power balancing constraints, which are defined below. All prices in this document are in units of $/MW-day.

$systemBalanceSP$ — Non-negative shadow price corresponding to the systemwide supply demand balancing constraint (4.5). This SP applies to all LRZs and ERZs.

$SRICSP_r$ — Non-negative shadow price corresponding to the subregional import constraint: left-hand side inequality of (4.6). A positive shadow price implies that the imports for subregion *r* are equal to the SRIC limit. The shadow price applies to all local zones in the respective subregion *r*. For external zones, the shadow price is assigned proportionally based on the respective subregional shift factors.

$SRECSP_r$ — Non-positive shadow price corresponding to the subregional export constraint: right-hand side inequality of (4.6); a negative value implies that the exports for subregion *r* are equal to the SREC limit. The shadow price applies to all local zones in the respective subregion *r*. For external zones, the shadow price is assigned proportionally based on the respective subregional shift factors.

$LCRSP_k$ — Non-negative SP for the LCR constraint (4.7) for LRZ $k \in Z$. This only applies to LRZs. A positive SP for the LRZ implies that the total cleared generation in LRZ *k* is either exactly equal to the LCR for *k*, or that the total generation offered in LRZ *k* is short of the LCR for *k* (in which case, seasonal CONE pricing is used as a shortage penalty).

$CILSP_k$ — Non-negative SP for the CIL constraint (4.8) for LRZ $k \in Z$. This only applies to LRZs. A positive SP implies that the difference between the initial PRMR and the total cleared generation in the LRZ is either exactly equal to CIL or is more than CIL in case of a shortage.

$CELSP_k$ — Non-positive SP for the CEL constraint (4.10) for zone $k \in Z \cup E$. This applies to both LRZs and ERZs.

The ex-ante ACP for an LRZ $k \in Z_r$ in subregion $r \in R$, prior to the calculation of LCR price adder is the minimum of (i) seasonal CONE of the LRZ and (ii) the sum of shadow prices corresponding to the LRZ (for zones without multi-season shortage, the ex-ante ACP will also be the ex-post ACP for the LRZ):

$$ACP_k^{EA} = min\{SEASONALCONE_k, systemBalanceSP + SRICSP_r + SRECSP_r + LCRSP_k + CILSP_k + CELSP_k\} \quad (4.11.a)$$

The ACP for an ERZ $e \in E$ is the minimum of (i) the maximum seasonal CONE of all the LRZs in the subregion to which the ERZ is connected (for dual connected ERZs, this is the maximum seasonal CONE of all LRZs in the entire transmission area; and (ii) the sum of the shadow prices corresponding to the ERZ:

$$ACP_e = min\{SEASONALCONE_e, systemBalanceSP + CELSP_e + \sum_r SF_{r,e} \times (SRICSP_r + SRECSP_r)\} \quad (4.11.b)$$

4.3.2 ACP under multi season LRZ shortages, or near-shortages, on local clearing requirement

When an LRZ has more than one season in any combination of ZRC shortage conditions and/or ZRC near-shortage conditions, the final Auction Clearing Price (ACP) for the LRZ will be determined as follows.

Let $\tilde{Z}$ the set of all LRZs with multi-season LCR or CIL shortage or near-shortage conditions. Let N_k^S denote the total number of shortage or near-shortage days for the LRZ $k \in \tilde{Z}$ across the entire planning year. Then, the LCR price adder for LRZ k is given by,

$$LCRPRICEADDER_k = CONE_k / N_k^S \quad (4.12)$$

The ex-post ACP for an LRZ k with multi-season shortage or near-shortage is,

$$ACP_k^{EP} = min\{SEASONALCONE_k, systemBalanceSP + SRICSP_r + SRECSP_r + LCRPRICEADDER_k\}, \quad \forall k \in \tilde{Z} \quad (4.13)$$

5 Final Auction Clearing Quantities for LRZs

The Final PRMR of an LSE is determined based on RBDC clearing in the corresponding subregion and the LSE's participation option (such as RBDC Opt Out, market participation, etc.)

in the PRA. The detailed procedure to determine Final PRMR is presented in Section 5.6 of this Business Practice Manual.

6 Examples

6.1 Small System Examples

Assume a system as shown in **Error! Reference source not found.** below. It consists of two L RZs and two subregions. There is a limited transfer capability between the subregions, and it is reflected in the subregional power balance constraint limit (SRPBC): the SRPBC limit in the following examples is a simplified representation of the SRIC/SREC constraints included in the preceding mathematical formulation.

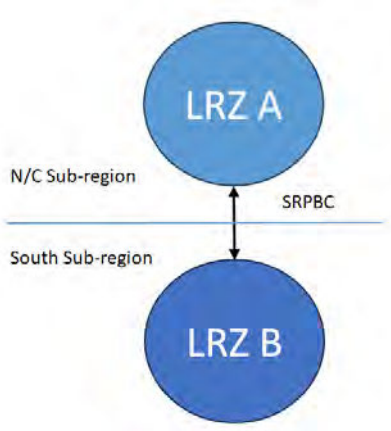


Figure 3. System setup for clearing examples: Two LRZ system with two subregions

Case 1: Regional RBDCs in both subregions are resulting in higher requirements than the share-of-systemwide RBDC, and there are no binding subregional import/export constraints. The offer and RBDC information along with the optimal clearing are shown in the following figure.

Systemwide RBDC

Price ($/MW)	Quantity (MW)
$40	35
$20	40
$10	43

N/C Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	20
$18	25
$12	28

South Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	13
$15	23
$7	31

Resource Offer

Resource	Sub-Region	Price ($/MW)	Quantity (MW)
R1	N/C Sub-region	$18	40
R2	N/C Sub-region	$16	40
R3	South Sub-region	$14	40
R4	South Sub-region	$13	40

SRPBC limit	100MW
Sub-regional load share of systemwide RBDC	50% N/C 50% South

Clearing

LRZ	ACP ($/MW.Day)	Effective Requirement (MW)	Cleared Quantity (MW)	Marginal resource offer ($/MW)
LRZ A	$14	25 (sub-regional RBDC)	0	$14
LRZ B	$14	23 (sub-regional RBDC)	48	$14

Resource Clearing

Resource	Sub-Region	ACP ($/MW.Day)	Offer Quantity (MW)	Cleared Quantity (MW)
R1	N/C Sub-region	$14	40	0
R2	N/C Sub-region	$14	40	0
R3	South Sub-region	$14	40	8
R4	South Sub-region	$14	40	40

Case 2: Regional RBDCs in both subregions are resulting in higher requirements than the share-of-systemwide RBDC, and the subregional import/export constraints are binding. The offer and RBDC information along with the optimal clearing are shown in the following figure.

Systemwide RBDC

Price ($/MW)	Quantity (MW)
$40	35
$20	40
$10	43

N/C Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	20
$18	25
$12	28

South Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	13
$15	23
$7	31

Resource Offer

Resource	Sub-Region	Price ($/MW)	Quantity (MW)
R1	N/C Sub-region	$18	40
R2	N/C Sub-region	$16	40
R3	South Sub-region	$14	40
R4	South Sub-region	$13	40

SRPBC limit	5 MW
Sub-regional load share of systemwide RBDC	50% N/C 50% South

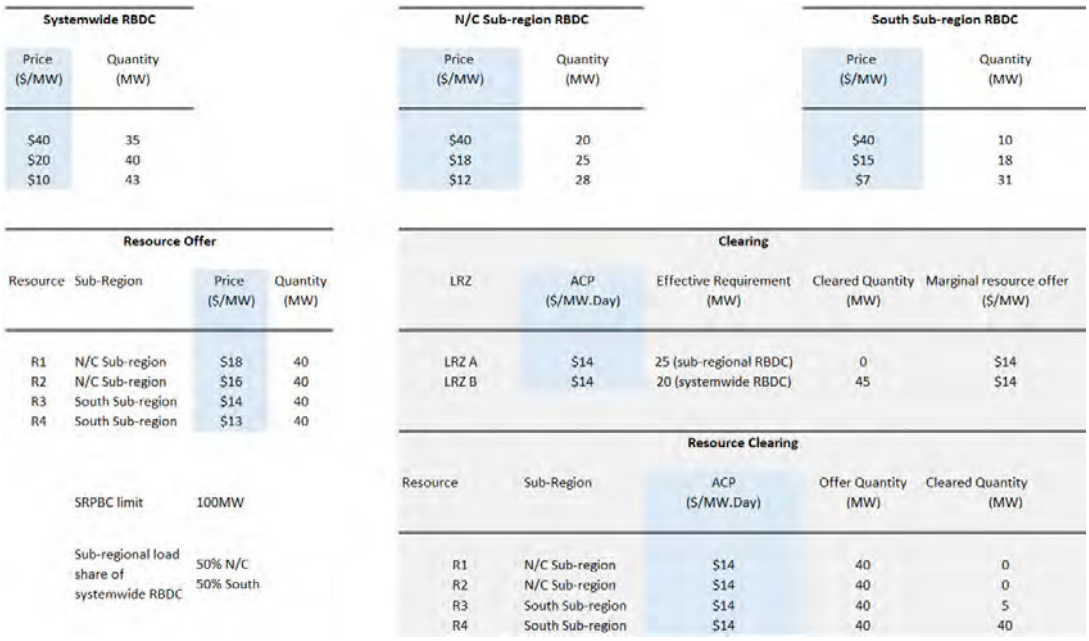
Clearing

LRZ	ACP ($/MW.Day)	Effective Requirement (MW)	Cleared Quantity (MW)	Marginal resource offer ($/MW)
LRZ A	$16	25 (sub-regional RBDC)	20	$16
LRZ B	$13	23 (sub-regional RBDC)	28	$13

Resource Clearing

Resource	Sub-Region	ACP ($/MW.Day)	Offer Quantity (MW)	Cleared Quantity (MW)
R1	N/C Sub-region	$16	40	0
R2	N/C Sub-region	$16	40	20
R3	South Sub-region	$13	40	0
R4	South Sub-region	$13	40	28

Case 3: In one subregion, share-of-systemwide RBDC is resulting in a higher requirement than subregional RBDC, while in the other subregion, the subregional RBDC results in a higher requirement as compared to the share-of-systemwide RBDC. SRIC/SREC are not binding. The offer and RBDC information along with the optimal clearing are shown in the following figure.



Systemwide RBDC

Price ($/MW)	Quantity (MW)
$40	35
$20	40
$10	43

N/C Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	20
$18	25
$12	28

South Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	10
$15	18
$7	31

Resource Offer

Resource	Sub-Region	Price ($/MW)	Quantity (MW)
R1	N/C Sub-region	$18	40
R2	N/C Sub-region	$16	40
R3	South Sub-region	$14	40
R4	South Sub-region	$13	40

SRPBC limit	100MW
Sub-regional load share of systemwide RBDC	50% N/C 50% South

Clearing

LRZ	ACP ($/MW.Day)	Effective Requirement (MW)	Cleared Quantity (MW)	Marginal resource offer ($/MW)
LRZ A	$14	25 (sub-regional RBDC)	0	$14
LRZ B	$14	20 (systemwide RBDC)	45	$14

Resource Clearing

Resource	Sub-Region	ACP ($/MW.Day)	Offer Quantity (MW)	Cleared Quantity (MW)
R1	N/C Sub-region	$14	40	0
R2	N/C Sub-region	$14	40	0
R3	South Sub-region	$14	40	5
R4	South Sub-region	$14	40	40

Case 4: In one subregion, share-of-systemwide RBDC is resulting in a higher requirement than subregional RBDC, while in the other subregion, the subregional RBDC results in a higher requirement as compared to the share-of-systemwide RBDC. SRIC/SREC are binding. The offer and RBDC information along with the optimal clearing are shown in the following figure.

Systemwide RBDC

Price ($/MW)	Quantity (MW)
$40	35
$20	40
$10	43

N/C Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	20
$18	25
$12	28

South Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	10
$15	18
$7	31

Resource Offer

Resource	Sub-Region	Price ($/MW)	Quantity (MW)
R1	N/C Sub-region	$18	40
R2	N/C Sub-region	$16	40
R3	South Sub-region	$14	40
R4	South Sub-region	$13	40

SRPBC limit	10MW
Sub-regional load share of systemwide RBDC	50% N/C 50% South

Clearing

LRZ	ACP ($/MW.Day)	Effective Requirement (MW)	Cleared Quantity (MW)	Marginal resource offer ($/MW)
LRZ A	$16	25 (sub-regional RBDC)	15	$16
LRZ B	$13	20 (systemwide RBDC)	30	$13

Resource Clearing

Resource	Sub-Region	ACP ($/MW.Day)	Offer Quantity (MW)	Cleared Quantity (MW)
R1	N/C Sub-region	$16	40	0
R2	N/C Sub-region	$16	40	15
R3	South Sub-region	$13	40	0
R4	South Sub-region	$13	40	30

Case 5: Systemwide RBDC results in a higher requirement in both subregions, and no SRIC/SREC binding. Offer, RBDC, and clearing details are in the following figure.

Price ($/MW)	Quantity (MW)
$40	35
$20	40
$10	43

Price ($/MW)	Quantity (MW)
$40	10
$18	15
$12	20

Price ($/MW)	Quantity (MW)
$40	3
$15	13
$7	21

Resource Offer

Resource	Sub-Region	Price ($/MW)	Quantity (MW)
R1	N/C Sub-region	$18	40
R2	N/C Sub-region	$16	40
R3	South Sub-region	$14	40
R4	South Sub-region	$13	40

SRPBC limit	500 MW
Sub-regional load share of systemwide RBDC	50% N/C 50% South

Clearing

LRZ	ACP ($/MW.Day)	Effective Requirement (MW)	Cleared Quantity (MW)	Marginal resource offer ($/MW)
LRZ A	$13	20 (system RBDC)	0	$13
LRZ B	$13	20 (system RBDC)	40	$13

Resource Clearing

Resource	Sub-Region	ACP ($/MW.Day)	Offer Quantity (MW)	Cleared Quantity (MW)
R1	N/C Sub-region	$13	40	0
R2	N/C Sub-region	$13	40	0
R3	South Sub-region	$13	40	0
R4	South Sub-region	$13	40	40

Case 6: Systemwide RBDC results in a higher requirement in both subregions, and SRIC/SREC are binding. Offer, RBDC, and clearing details are in the following figure.

Systemwide RBDC

Price ($/MW)	Quantity (MW)
$40	35
$20	40
$10	43

N/C Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	10
$18	15
$12	20

South Sub-region RBDC

Price ($/MW)	Quantity (MW)
$40	3
$15	13
$7	21

Resource Offer

Resource	Sub-Region	Price ($/MW)	Quantity (MW)
R1	N/C Sub-region	$18	40
R2	N/C Sub-region	$16	40
R3	South Sub-region	$14	40
R4	South Sub-region	$13	40

SRPBC limit	5 MW
Sub-regional load share of systemwide RBDC	50% N/C 50% South

Clearing

LRZ	ACP ($/MW.Day)	Effective Requirement (MW)	Cleared Quantity (MW)	Marginal resource offer ($/MW)
LRZ A	$16	20 (system RBDC)	15	$16
LRZ B	$13	20 (system RBDC)	25	$13

Resource Clearing

Resource	Sub-Region	ACP ($/MW.Day)	Offer Quantity (MW)	Cleared Quantity (MW)
R1	N/C Sub-region	$16	40	0
R2	N/C Sub-region	$16	40	15
R3	South Sub-region	$13	40	0
R4	South Sub-region	$13	40	25

6.2 PRA Clearing Examples using Indicative RBDCs

This section provides an illustrative graphical representation of the auction clearing with RBDCs: the plots representing the PRA clearing outcomes with indicative RBDCs for PY 24-25 Summer Season are presented in **Error! Reference source not found.**. The indicative RBDCs are d eveloped based on PY 24-25 loss-of-load study and the associated models. Resource offers submitted for the PY 24-25 Summer Season are used for the supply curves. The parameters for the zonal CIL, CEL, and LCR constraints are the same as those used in the PY 2024/25 PRA. The solution to the linear programming-based formulation results in an Auction Clearing Price of about $140/MW-day with no subregional or zonal price separation. The systemwide RBDC is setting up the requirement in both subregions with a total cleared demand of 140.1GW, because the share-of-systemwide RBDCs are to the right of the subregional RBDCs in both subregions.

The SREC limit from the south subregion to the north/central subregion is 1,900 MW; the capacity exports from the south subregion to the north/central subregion are 1,581 MW as reflected in **Error! Reference source not found.**. The RBDCs shown in the dashed lines for t

he exporting subregion (south) have been shifted to **the right by the export quantity**, while those for the importing subregion (N/C) have been shifted to **the left by the same quantity**. The original RBDCs are in solid lines.

The horizontal line represents the ACP, which is set at the intersection of the supply curve and import/export-shifted RBDC for each subregion (red dot in the figure). The Final PRMR for an importing subregion (N/C) is to the **right** of the intersection of the supply curve and the import-shifted RBDC by the import quantity (1,581 MW in the figures below). Similarly, for the exporting subregion (south), the final PRMR is to the **left** of the intersection of the supply curve and the export-shifted RBDC by the export quantity of 1,581 MW. The Final PRMR is shown by the dotted dark-gray vertical line passing through the intersection of the horizontal ACP line and the requirement-setting RBDC (share-of-systemwide RBDC for Summer 2024 in both subregions—plots in orange solid lines).

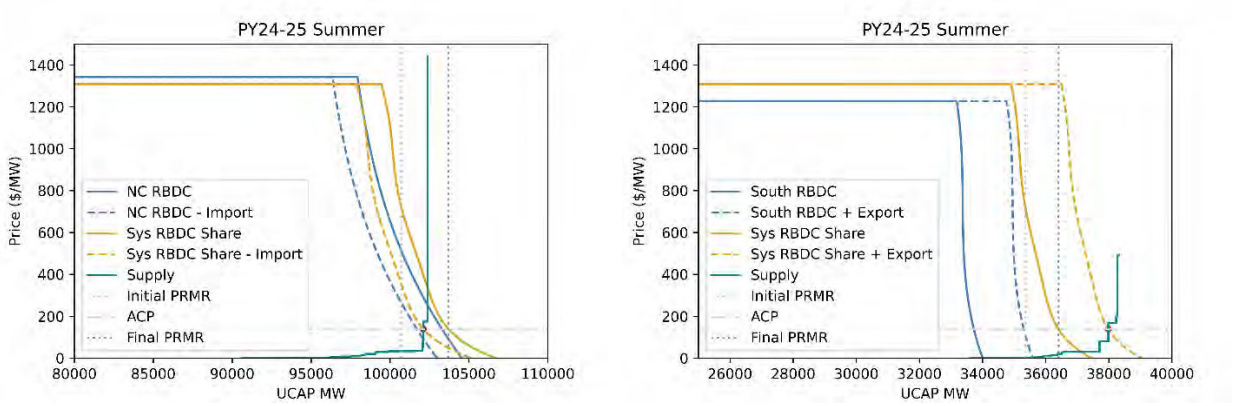


Figure 4. PRA clearing with indicative RBDCs representing PY24-25 Summer season with actual offers submitted for PY24-25 Summer season.

For completeness, the zoomed-in version of PRA clearing presented in **Error! Reference source not found.** is shown below in **Error! Reference source not found.**.

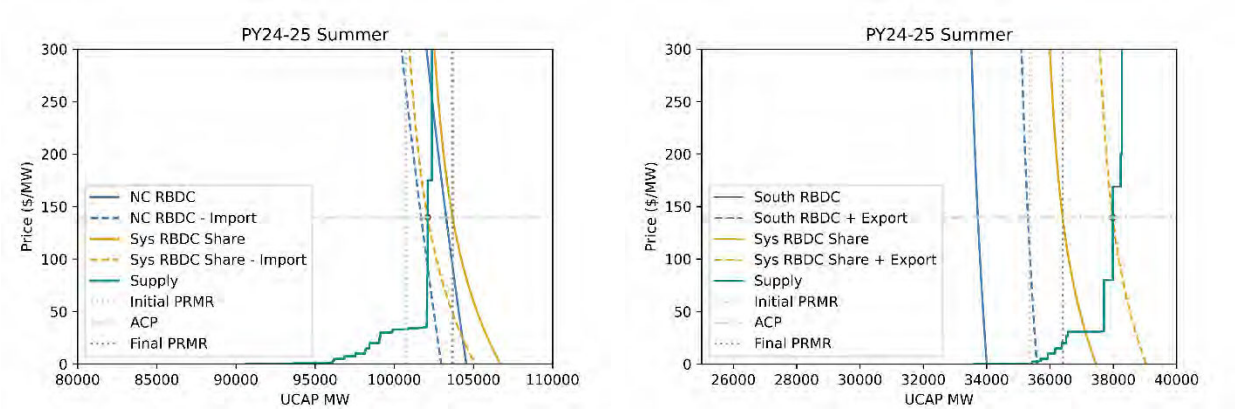


Figure 5. Zoomed in version of illustrative PY 24-25 Summer season PRA clearing

Appendix N – Seasonal Demand and Energy Forecast Characteristics

Forecast Criteria	Coincident Peak Demand and Zonal Coincident Peak Demand Forecasts	Non-Coincident Peak Demand Forecast	Energy for Load Forecast
Includes Demand Served by Energy Efficiency Planning Resources	Yes	Yes	Yes
Includes Demand Served by Energy Efficiency Programs	No	No	No
Includes Demand Served by Demand Resources	Yes	Yes	Yes
Includes Demand Served by BTMG Planning Resources	Yes	Yes	Yes
Includes Demand Served by resources that are not qualified as Planning Resources	Yes	No	No
Includes Demand Pseudo-Tied Out of MISO BA and Included Subject to other RAR	No	Yes	Yes
Includes Transmission Losses	No	No	Yes
Coincident with reporting Load Serving Entities' system	No	Yes	No
Demand reported at Physical LBA Location	Yes	Yes	Yes
Include Demand from Power Plant Station or Auxiliary Needs	No	No	No

Appendix O – Parties Responsible for Reporting Seasonal Demand and Energy Forecasts

Data	EDC	Retail Choice LSE	Non-Retail Choice LSE
MISO Coincident Peak (Total CPF)	No	No	Yes
MISO Non-Coincident Peak (Total NCPF)	No	No	Yes
Zonal Coincident Peak (Total CPF)	No	No	Yes
RC Coincident Peak (Total CPFEDC Area)	Yes	No	No
RC Coincident Peak (Total NCPF) Load Contribution	Yes	No	No
RC Zonal Coincident Peak (Total CPFEDC Area)	Yes	No	No
Non-Coincident Peak	Yes	No	Yes
RC Non-Coincident Peak	No	Yes	No
Energy for Load	Yes	No	Yes
Retail Choice (MISO Peak)	Yes	No	No
Retail Choice (Zonal Peak)	Yes	No	No

Appendix P – Zonal Deliverability Benefit *Pro Rata* Allocation

This Appendix is an illustrative example of the ZDB *pro rata* allocation methodology in the presence of Historical Unit Considerations (HUC) and Fixed Resource Adequacy Plan (FRAP) or RBDC Opt Out. The results from the Planning Resource Auction for the 2020/2021 Planning Year are used in this example to educate Market Participants. The resulting Auction Clearing Prices illustrated here are different than those settled for the 2020/2021 Planning Year. Starting in Planning Year 2023-2024, the ZDB calculation will be performed separately for each Season in which the ZDB calculation is required.

Step 1Subtract PRMR and ZRCs associated with HUC Hedges to derive an adjusted Final PRMR (Adjusted Final PRMR) and ZRC (Adjusted ZRC). ZRCs are FRAP + RBDC Opt Out + Self-scheduled offers + cleared Non-self-scheduled offers.

RZ	ACP	Final PRMR	ZRC	HUC (MW)	ZDC Hedges (MW)	Adjusted Final PRMR	Adjusted ZRC
Z1	$5.00	18,476.0	18,742.0	191.7	0	18,284.3	18,550.3
Z2	$5.00	13,728.2	13,590.0	0	0	13,728.2	13,590.0
Z3	$5.00	10,129.1	10,551.0	0	0	10,129.1	10,551.0
Z4	$5.00	9,794.6	8,462.1	0	0	9,794.6	8,462.1
Z5	$5.00	8,456.3	7,952.8	0	0	8,456.3	7,952.8
Z6	$5.00	18,720.6	17,054.6	0	0	18,720.6	17,054.6
Z7	$257.53	21,945.3	21,727.5	0	0	21,945.3	21,727.5
Z8	$4.75	7,986.9	10,183.1	0	0	7,986.9	10,183.1
Z9	$6.88	21,711.7	20,893.7	107.3	0	21,604.4	20,786.4
Z10	$4.75	5,030.6	5,244.2	0	0	5,030.6	5,244.2
E20	$4.90	0.0	347.2	0	0	0.0	347.2
E22	$5.00	0.0	633.8	0	0	0.0	633.8
E23	$5.00	0.0	30.1	0	0	0.0	30.1
E24	$5.00	0.0	148.4	0	0	0.0	148.4
E26	$4.92	0.0	24.0	0	0	0.0	24.0
E27	$4.89	0.0	168.3	0	0	0.0	168.3
E28	$4.90	0.0	226.5	0	0	0.0	226.5

Step 2: Create a DBZ for each group of LRZs that have equal ACPs which result from the same auction constraint. In this example, Zone 7 is a DBZ because the PRA bound on its LCR.

RZ	ACP	Adjusted Final PRMR	Adjusted ZRC	DBZ Grouping
Z1	$5.00	18,284.3	18,550.3	Zone A
Z2	$5.00	13,728.2	13,590.0	Zone A
Z3	$5.00	10,129.1	10,551.0	Zone A

Z4	$5.00	9,794.6	8,462.1	Zone A
Z5	$5.00	8,456.3	7,952.8	Zone A
Z6	$5.00	18,720.6	17,054.6	Zone A
Z7	$257.53	21,945.3	21,727.5	Zone B
Z8	$4.75	7,986.9	10,183.1	Zone D
Z9	$6.88	21,604.4	20,786.4	Zone C
Z10	$4.75	5,030.6	5,244.2	Zone D
E20	$4.90	0.0	347.2	Zone E
E22	$5.00	0.0	633.8	Zone A
E23	$5.00	0.0	30.1	Zone A
E24	$5.00	0.0	148.4	Zone A
E26	$4.92	0.0	24.0	Zone F
E27	$4.89	0.0	168.3	Zone G
E28	$4.90	0.0	226.5	Zone E

Step 3: For each DBZ, subtract the sum of Adjusted Final PRMR for each LRZ within the DBZ from the sum of Adjusted ZRCs for each LRZ within the DBZ. A DBZ will be considered a net importing DBZ if the sum of Adjusted Final PRMR is greater than the sum of Adjusted ZRCs. A DBZ will be considered a net exporting DBZ if the sum of the Adjusted Final PRMR is less than the sum of Adjusted ZRCs. A net exporting DBZ shall not receive any ZDB credit. A net importing DBZ shall receive a ZDB credit allocation based upon this weighted average approach.
In this example, Zones A, B, and C are net importing DBZ's and Zones D, E, F and G are net exporting DBZs.

DBZ	Adjusted Final PRMR	Adjusted ZRC	Difference	Result
Zone A	79,113.1	76,973.1	-2140.0	Net Importer
Zone B	21,945.3	21,727.5	-217.8	Net Importer
Zone C	21,711.7	20,893.7	-818.0	Net Importer
Zone D	13,017.5	15,427.3	2,409.8	Net Exporter
Zone E	0.0	573.7	573.7	Net Exporter
Zone F	0.0	24.0	24.0	Net Exporter
Zone G	0.0	168.3	168.3	Net Exporter

Step 4: Calculate the weighted average ACP of all net exporting DBZs (Weighted Average Export ACP) to determine a financial value of export capacity within the Transmission Provider region per the formula below:

$$\text{Weighted Average Export ACP} = \frac{\sum(\text{Net Export}_j \times \text{ACP}_j)}{\sum \text{Net Export}_j}$$

Where j = Each net exporting DBZ

DBZ	Net Export	ACP	Net Export*ACP
D	2409.8	$4.75	$11,446.55
E	573.7	$4.90	$2,811.13
F	24	$4.92	$118.08
G	168.3	$4.89	$822.99
Total of Exporting Zones	3175.8		$15,198.75
Weighted Average Export ACP =(Total Net Export*ACP)/(Total Net Export)			$4.79

Step 5: Calculate the ZDB credit allocation, in dollars, for each net importing DBZ:

$$\text{ZDB Credit}_k = \text{Net Import}_k \times (\text{ACP}_k - \text{Weighted Average Export ACP})$$

Where k = Each net importing DBZs

DBZ	Net Import	ACP ($/MW-day)	Weighted Average Export ACP	ZDB Credit ($/day)
A	2140.0	$5.00	$4.79	$458.39
B	217.8	$257.53	$4.79	$55,047.69
C	818.0	$6.88	$4.79	$1,713.05
Total of Importing Zones	3175.8			

Step 6: Distribute the ZDB credit in each DBZk by dividing the ZDB credit by the sum of Adjusted Final PRMR of the LRZs within each DBZk. Subtract this amount from the initial ACP calculated for each LRZ from the PRA.

DBZ	ZDB Credit ($/day)	RZ	Adjusted Final PRMR	ZDB Rate ($/MW-day)	ACP	Net ACP
A	$458.39	1	18,284.3	$0.01	$5.00	$4.99
		2	13,728.2			
		3	10,129.1			
		4	9,794.6			
		5	8,456.3			
		6	18,720.6			
		Total DBZ A	79,113.1			
B	$55,047.69	7	21,945.3	$2.51	$257.53	$255.02
C	$1,713.05	9	21,604.4	$0.08	$6.88	$6.80

Appendix Q – Fleet XEFORd Calculation

This appendix walks through the process for calculating fleet XEFORd. This process is used for External Resources that participate in the PRA as one MECT resource which represents the aggregate of a fleet of units. In order to qualify, resource owners must submit help tickets to help.misoenergy.org to let MISO know which resources to be included in your fleet by November 15, otherwise the resource will not be able to participate in the PRA. For example, an external area might have 100 units in its fleet with a total capacity of 10,000 MW of which it plans to commit 1,000 MW on an installed capacity basis to MISO. MISO will then calculate a seasonal SAC based on a seasonal weighted average forced outage rate of all units in the fleet. Intermittent and class average units are excluded from the fleet XEFORd calculation. This appendix will walk through a weighted average example calculation for a set of fleet units.

Utility	Unit	Unit Name	GVTC (MW)	XEFORd (%)	Weighted XEFORd (%)
99A - Midwest ISO	101	Carmel 1	100.0	15.0%	4.5%
99A - Midwest ISO	102	Carmel 2	120.0	10.0%	3.6%
99A - Midwest ISO	601	Eagan 1	65.0	7.5%	1.5%
99A - Midwest ISO	602	Eagan 2	50.0	5.0%	0.7%
99A - Midwest ISO	501	Little Rock 1	20.0	Intermittent	Excluded
99A - Midwest ISO	502	Little Rock 2	25.0	Intermittent	Excluded
99A - Midwest ISO	401	Metarie 1	5.0	Class average	Excluded
99A - Midwest ISO	402	Metarie 2	3.0	Class average	Excluded
		Fleet Total	388.0		
		Fleet Total included in Fleet XEFORd Calculation	335.0		10.3%

Formulas

- Unit Weighted Average XEFORd = (Unit GVTC (MW)) / (Total GVTC (MW)) * (Unit XEFORd)

  (for Carmel 1 weighted XEFORd is 100.0/335.0*15.0% = 4.5%)

- Fleet Total GVTC (MW) = Sum of GVTC (MW) for all units

  (100.0 + 120.0 + 65.0 + 50.0 + 20.0 + 25.0 + 5.0 +3.0 = 388.0)

- Fleet GVTC w/ XEFORd = Sum of GVTC for all units with an XEFORd value

  (100.0 + 120.0 + 65.0 + 50.0 = 335.0)

- Fleet Weighted XEFORd = Sum of Weighted XEFORd for all units

  (4.5% + 3.6% + 1.5% + 0.7% = 10.3%)

Appendix R – Annual CONE Calculation

MISO calculates gross Cost of New Entry (CONE) values for each LRZ for each Planning Year. This CONE value will be used for all Seasons within the entire Planning Year. MISO calculates CONE for each LRZ based upon the costs associated with an advanced combustion turbine generator (CT). MISO uses the following approach:

1. MISO begins with an estimate of a CONE value not specific to an LRZ,
2. MISO uses "the law of one price" where applicable (e.g., turbines that are sold competitively),
3. MISO develops zonal differences to reflect different locational costs (e.g., labor, technical enhancements and others) using the most recent United States Energy Information Administration (EIA) document, and
4. MISO uses the Net Present Value (NPV) algorithm to calculate CONE values for each LRZ.

MISO allows factors such as the weighted average cost of capital, escalation rates, and other factors where global competition drives prices to have no locational differences to be constant.

In order to determine the appropriate CONE value for each LRZ, MISO relies upon the most recent EIA report on "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies (EIA Report)". The EIA Report contains detailed specifications for a hypothetical advanced CT, including information regarding the differences in project costs for an advanced CT with a nominal capacity of 237 MW, based upon the state where the facility is constructed. The report is available at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/.

MISO uses an NPV analysis to determine an appropriate CONE value for hypothetical advanced CTs located in each LRZ. In accordance with Section 69A.8.a of Module E-1, MISO considers many factors in its calculation of the CONE value, including the following: (1) physical factors (such as, the type of Generation Resource that could reasonably be constructed to provide Planning Resources, costs associated with locating the Generation Resource within the Transmission Provider Region, the estimated costs of fuel for the Generation Resource); (2) financial factors (such as, the hypothetical debt/equity ratio for the Generation Resource, the cost of capital, a reasonable return on equity, applicable taxes, interest, insurance); and (3) other costs (such as, costs related to permitting, environmental compliance, operating and

maintenance expenses). MISO does not consider the anticipated net revenue from the sale of capacity, Energy or Ancillary Services.

CONE values for each Planning Year are based, in part, upon data supplied by the EIA, which are adjusted using the implicit price deflator from the Bureau of Economic analysis in order to convert EIA cost data into present value dollars. In order to produce the annualized CONE value for each LRZ from these cost numbers, for the 2023/2024 Planning Resource Auction MISO assumed: (i) a 55/45 debt to equity ratio; (ii) a 20-year project life and loan term; (iii) a 5.16 percent debt interest rate; (iv) a 2.2 percent Operation and Maintenance escalation factor; (v) a 2.2 percent GDP deflator; (vi) a 25-31 percent combined effective federal and state tax rate; (vii) property tax and insurance costs of 1.5 percent of the capital costs; (viii) a calculated weighted average cost of capital of 7.99 to 8.17 percent; (ix) and a 13.4 percent after tax internal rate of return on equity. None of these factors vary by LRZ to any significant degree that is discernible in available data. MISO will continue to examine these factors in the future to determine if any LRZ specific modifications are indicated. These factors and assumptions are comparable to those used by other RTOs in the development of CONE estimates.

Steps for calculating CONE

1. Obtain latest 'Base Project Cost $/kW'
   Obtain the latest Energy Information Administration (EIA) report for *EIA,* Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies. It provides the following data:

   - Plant Capital Cost in $/kW. MISO currently uses the number for advanced CT.
   - Location Based Costs Table: Location Percent Variation, Delta Cost Difference and Total Location Project Cost columns

2. Use Bureau of Economic Analysis (BEA) data to calculate implicit price deflator
   Use Table 1.1.9 - Implicit Price Deflators for Gross Domestic Product from NIPA data. Using the table, calculate the *Escalation Rate* from base year to planning year, based on historical and projected quarterly PCE deflator values. Use this Escalation Rate to calculate "Total Location Project Cost" in current year dollars.

3. Calculate LRZ and Base total capital costs, adjusted by multiplying with the Escalation Rate
   For LRZs - Use averages of adjusted project costs for locations (for which data is available) in each zone.

4. Calculate the after-tax weighted average cost of capital (WACC)

$WACC = (E * R_e) + (D * R_d * (1 – T_c))$.

Where E = Equity Fraction of Project

R_e = Cost of Equity. Assume as the after-tax IRR

D = Debt Fraction of Project

R_d = Cost of Debt (20-year BB corporate bond rate)

T_c = Combined effective federal and state tax rate

5. Calculate estimated annualized costs for each LRZ and also for the Base.

- Calculate annualized capital costs using total capital costs, after-tax WACC and assuming the project lifespan. (Use PMT function)
- Calculate the O&M costs based on O&M data, project lifespan, WACC and US GDP Deflator (Use PMT and NPV functions)
  - Assume suitable O&M escalation factor
  - Assume/Update US GDP Deflator
- Assume insurance and property tax costs.

Appendix S – Example Scenarios of "Excess BTMG"

This Appendix shares a few illustrative examples of how BTMG may change to "Excess BTMG" from one year to the next. The examples below show how some specific factors may cause BTMG to be classified as "Excess BTMG" from one year to the next. Below are four examples of "Excess BTMG".

(All PRMR being referred in this appendix are Final PRMR cleared through PRA auction)

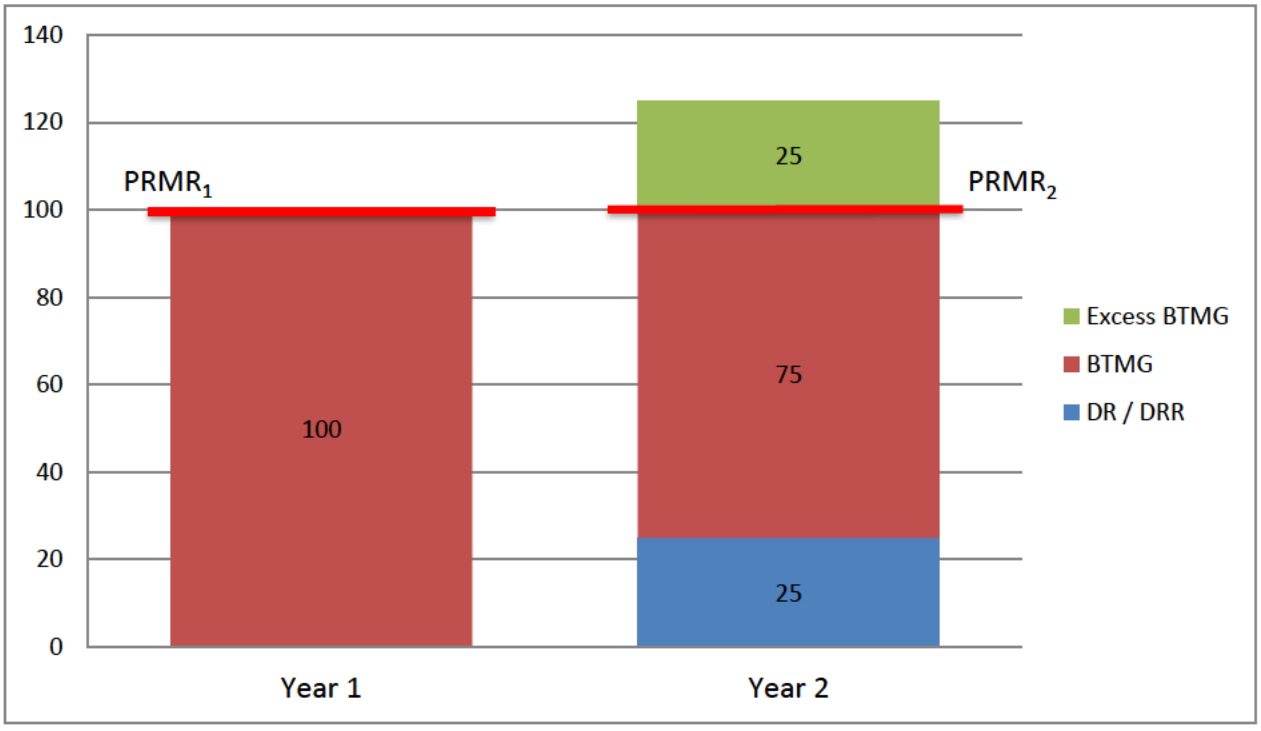
1. Increase in BTMG and No Change to Seasonal PRMR

The chart below illustrates the scenario in which a Market Participant experiences an increase in BTMG SAC from one year to the next while PRMR remains unchanged. In Year 1, the chart shows that the BTMG SAC is 100 MW and the seasonal PRMR is 100 MW; therefore, the Market Participant has no "Excess BTMG" in Year 1. Between Year 1 and Year 2, the Market Participant experiences an increase in BTMG of 25 MW—however, seasonal PRMR remains unchanged. In Year 2, the chart shows that BTMG SAC is 125 MW and the seasonal PRMR is 100 MW; therefore, the Market Participant has 25 MW of "Excess BTMG" in Year 2.



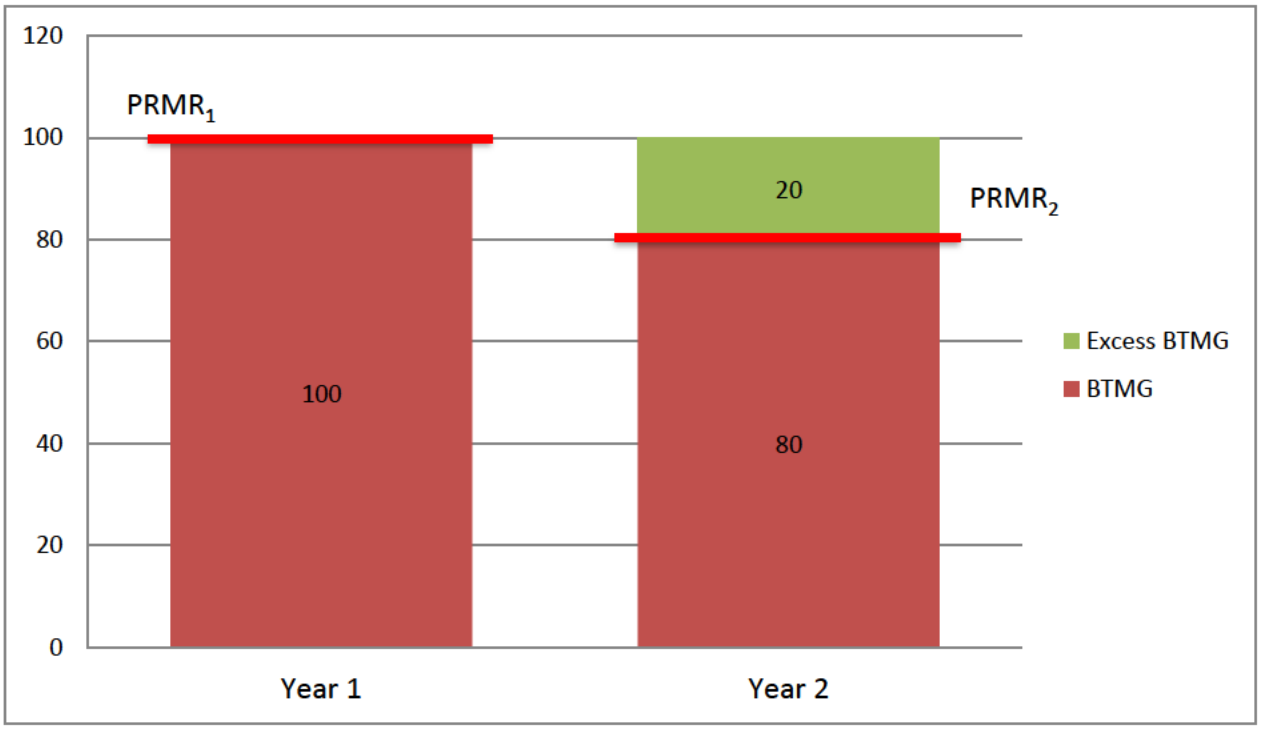
2. Increase in Demand Resources and/or Demand Response Resources and No Change to PRMR

The chart below illustrates the scenario in which a Market Participant experiences an increase in DR / DRR SAC from one year to the next while seasonal PRMR remains unchanged. In Year 1, the chart shows that the BTMG SAC is 100 MW and the seasonal PRMR is 100 MW; therefore, the Market Participant has no "Excess BTMG" in Year 1. Between Year 1 and Year 2, the Market Participant experiences an increase in DR / DRR SAC of 25 MW, however, seasonal PRMR remains unchanged. In Year 2, the chart shows that DR / DRR is 25 MW and BTMG is 100 MW and the seasonal PRMR is 100 MW. Since DR / DRR is netted against seasonal PRMR, the BTMG is stacked on top of the DR / DRR; therefore, the Market Participant has 25 MW of "Excess BTMG" in Year 2.



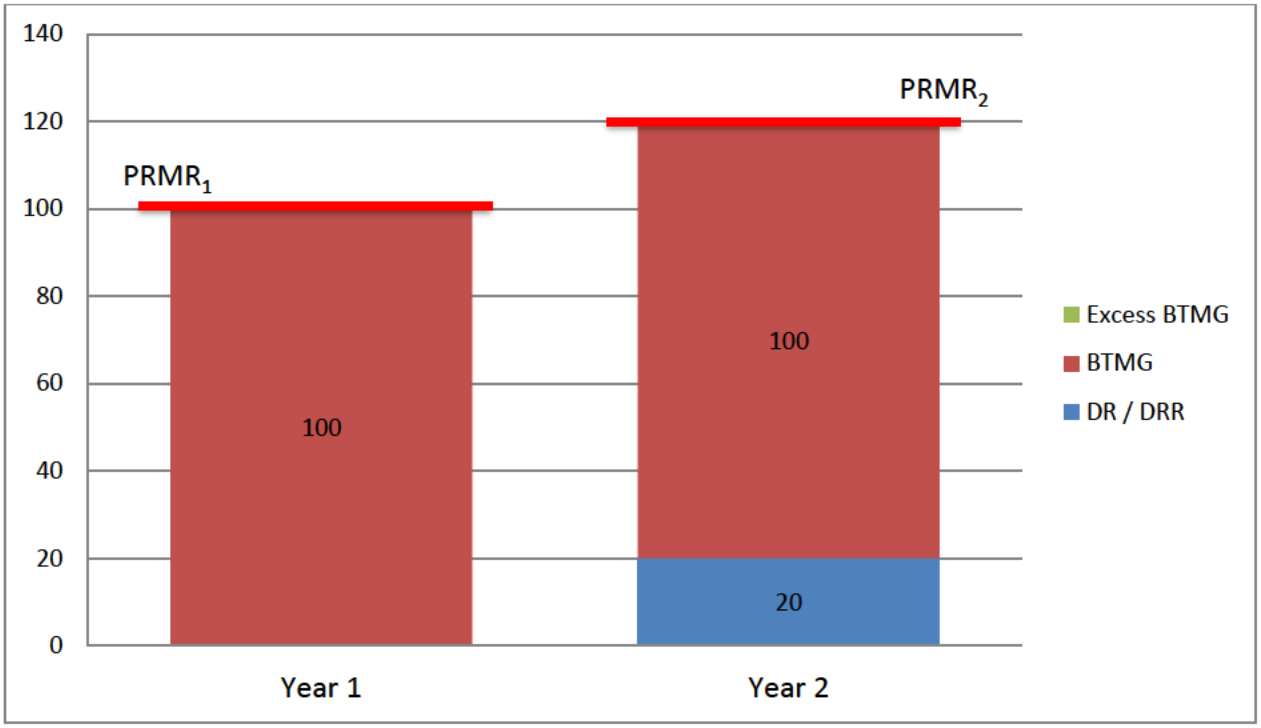
3. No Change to BTMG and Decrease to Seasonal PRMR

The chart below illustrates the scenario in which a Market Participant experiences a decrease in seasonal PRMR from one year to the next while BTMG SAC remains unchanged. In Year 1, the chart shows that the BTMG is 100 MW and the seasonal PRMR is 100 MW; therefore, the Market Participant has no "Excess BTMG" in Year 1. Between Year 1 and Year 2, the Market Participant experiences a decrease in seasonal PRMR of 20 MW, however, BTMG SAC remains unchanged. In Year 2, the chart shows that BTMG is 100 MW the seasonal PRMR is now 80 MW; therefore, the Market Participant has 20 MW of "Excess BTMG" in Year 2.



4. Equal Amount Increase in DR / DRR and Seasonal PRMR

The chart below illustrates the scenario in which a Market Participant experiences an equal increase in DR / DRR SAC and seasonal PRMR from one year to the next while BTMG SAC remains unchanged. In Year 1, the chart shows that the BTMG is 100 MW and the seasonal PRMR is 100 MW; therefore, the Market Participant has no "Excess BTMG" in Year 1. Between Year 1 and Year 2, the Market Participant experiences an equal increase in DR / DRR and seasonal PRMR of 20 MW each, however, BTMG remains unchanged. In Year 2, the chart shows that DR / DRR is 20 MW, BTMG is 100 MW and the seasonal PRMR is 120 MW. Since DR / DRR is netted against seasonal PRMR, the BTMG is stacked on top of the DR / DRR, however, due to the equal increase in DR / DRR and seasonal PRMR there is no "Excess BTMG" in Year 2.



Appendix T – ICAP Deferral Notice

ICAP Deferral Notice
Midcontinent Independent System Operator
720 City Center Drive
Carmel, IN 46032-7574
Attn.: Resource Adequacy
(Delivered via email to help@misoenergy.org)

[Current Date]

[Insert Company Name] ICAP Deferral Notice – [Planning Resource Name/CPNode Name, if applicable]
Select Planning Resource being deferred:
☐Generation Resource – [Insert CPNode Name, Unit Number]
☐Dispatchable Intermittent Resource (DIR) – [Insert Name]
☐Demand Response Resource (DRR) – [Insert Name]
☐External Resource – [Insert Name]
☐Behind the Meter Generation (BTMG) – [Insert Name]

Dear Resource Adequacy,

[Insert Company Name] is providing this written notification in accordance with Section 69A.7.9 of the Midcontinent Independent System Operator (MISO) Tariff, Module E-1 Resource Adequacy regarding an Installed Capacity (ICAP) Deferral for the Planning Resource selected above. [Insert Company Name] intends to increase ICAP between March 1 and the last Business Day of the applicable Season(s) for the [Insert Planning Year] Planning Year.

[Contact Name, Phone Number and Email]	Planning Resource Type
MISO MP ID/NERC ID of Company	
Planning Resource Name	
Local or External Resource Zone (LRZ or ERZ) where located	
Planning Resource Fuel Type	
Estimated ICAP Value (MW) *Note: this is the total ICAP value not the incremental increased value from a prior ICAP*	Summer
	Fall
	Winter
	Spring
Check applicable deferred Season(s)	Summer [ ], Fall [ ], Winter [ ], Spring [ ]
Estimated completion date of ICAP	
Reason for deferring (See Appendix U)	
Please fill out the following that is applicable to the Planning Resource being deferred:	
Generation Interconnection Agreement (GIA) Number and expected contract execution date *Note: only necessary if deferral includes upgrades to Interconnection Service*	

Expected NRIS and ERIS values with Interconnection Service upgrades	
Commercial Operation Date	
TSR Number	

Sincerely,
[Name], [Title – must be an officer], [Company Name], [Contact Information]

Appendix U – ICAP Deferral Examples

- Deliverability

Example 1: Unit is capable of testing at 150 MW, but currently only has 100 MW of NRIS with MISO. The unit is in the queue to have its NRIS increased to 150 MW by the last Business Day prior to the start of a Season in the upcoming Planning Year. Although the difference is 50 MW, the MP would submit an ICAP Deferral Notice for the total ICAP amount of 150 MW. For a Schedule 53 resource, even though the ICAP will increase, SAC will not. For a non-Schedule 53 resource, both ICAP and SAC will increase.

- Increased GVTC and Deliverability

Example 1: Unit currently tested for 100 MW and has 100 MW of NRIS. The unit is in the queue to have NRIS increased to 150 MW and plans to retest after upgrades are in place. Although the difference is 50 MW, the MP would submit an ICAP Deferral Notice for the total ICAP amount of 150 MW. Please note that the current unit should already submit a GVTC test of 100 MW by October 31.

- Commercial Operation

Example 1: The unit currently is subject to an environmental regulation that prevents the unit from operating. The unit is in the process of installing additional equipment to comply with the new environmental regulation. Thus, the unit is deferring GVTC until after all necessary approvals are completed.
Example 2: A resource that is a Dispatchable Intermittent Resource (DIR) would not submit GVTC, but instead receives capacity accreditation based on past historical data. If a DIR is new and is not expected to have Commercial Operation approved until after March 1, then it would be eligible to qualify for capacity credit by submitting an ICAP Deferral for Commercial Operation if Commercial Operation is expected before the last Business Day of prior to the deferred Season.
Example 3: The unit is currently waiting for upgrades to existing Interconnection Service and the upgrades have been completed, however, the unit has yet to be declared Commercial with MISO. The resource owner needs to file an Exhibit E with MISO Resource Integration to finalize the Commercial Operation of the unit. The unit must be in the March Commercial Model prior to the start of the Planning Year. Once this has been done, the Commercial Operation deferral will be considered complete. The resource owner should assist with coordination with MISO Resource Adequacy and MISO Resource Integration throughout the process.

- Suspension of Catastrophic Outage

Example 1: A unit is planning to return from suspension in August and will submit a new GVTC for the upcoming Fall Season prior to the last Business Day of the summer Season. Units returning from suspension are required to retest. The MP may defer the retested value.

- TSR Number

Example 1: A unit is planning to participate in the upcoming Planning Year; however, the unit does not have a Transmission Service Request (TSR) or NITS Scheduling Rights (SR) on the MISO OASIS with a status of “Confirmed” by March 1 to convert the SAC to ZRC to offer into the Auction. The unit expects to have its TSR or SR Confirmed by MISO prior to the last Business Day of prior to the start of the deferred Season. Once the TSR achieves “Confirmed” status on the MISO OASIS, the MP should reach out to help.misoenergy.org. If the TSR or SR status is “Confirmed” prior to June 1, the deferral requirement has been met.

- Additional GVTC Examples

Example 1: The unit defers 100 MW and the test submitted is for 80 MW. The unit is required to replace the UCAP value of 20 ICAP MW. For example, if the XEFORd for the unit is 25%, then the deferred ZRCs is 75 and the submitted test ZRCs is 60. The MP is required to replace the difference of 15 ZRCs through Resource Replacement, Interconnection Service, Cleared Volumes, Bi-lateral ZRC transactions, etc.

Appendix V – Solar and Run-of-River Hydro Accreditation

This appendix walks through examples for calculating solar and run-of-river hydro accreditation. For existing solar resources, the total Seasonal Accredited Capacity (SAC) is determined by the historical average output of the resource during the Summer, Fall, and Spring Seasons for the hours ending 15, 16, and 17 EST and for hours ending 8, 9, 19, and 20 EST for the Winter Season. Existing run-of-river hydro resources can submit up to 15 years of output data over the same hours as for solar resources, with total SAC determined by the median of that data. Market Participants will use the Non-GADS Performance Template found on the MISO website to submit the appropriate historical data for the upcoming Planning Year. The Non-GADS Performance Template can be found on the MISO website under Planning > Resource Adequacy > PRA Documents > PY (Current Plan Year). The populated template should be submitted to MISO by October 31 of each year via the Module E Capacity Tracking (MECT) tool.

For new solar resources, the maximum SAC that can be accredited is 50% for summer, fall, and spring and 5% for winter of the unit's registered maximum output or nameplate capacity. To convert all SAC to seasonal ZRCs, the resource would need to show firm deliverability through NRIS or ERIS with a firm TSR equaling the resource's ICAP value.

For existing solar resources, the historical performance used to calculate the resource's total SAC for a given Season is based on their average output over the defined seasonal peak hours for the last 3 years.

- The amount of total SAC that is convertible into ZRCs is based on the amount of deliverability (NRIS or ERIS with a firm TSR)
- Convertible SAC = total SAC * (deliverability-adjusted capacity factor / peak performance capacity factor)
- Where:
    - Peak performance capacity factor is calculated is calculated by taking an average of the resource's output and then dividing by nameplate capacity.
    - Deliverability-adjusted capacity factor is calculated by adjusting the adjusting output across the seasonal peak hours so that it is capped to the resource's deliverability, taking an average of the resource's output, and then dividing by nameplate capacity.

The examples below show how solar capacity credit is calculated for new resources in the Summer Season only—however, the examples may also be applied to run-of-river hydro resources as well. For the purposes of the examples, the following information will be used in each:

Solar Nameplate = 10 MW
Transmission Losses (vary by LBA) = 5%
Solar Class Average Summer Capacity Credit = 50%
Year 1 Average Historical Summer Output = 6.5 MW (Year 1 data only)
Year 2 Average Historical Summer Output = 7.0 MW (Average of Years 1 and 2 data)

Example 1: New solar (or run-of-river hydro) resources with less than 30 consecutive Summer days or no Summer data

In this example, the new solar resource does not have any historical Summer performance data to submit. Thus, the solar resource will receive the solar class average accreditation for the initial Summer Season in the Planning Year. In Year 2, the resource will use the average (run-of-river hydro resources use a median value) historical Summer performance from Year 1 to determine the accredited amount. In Year 3, the resource will use the average historical Summer performance from Years 1 and 2. In Year 4, the resource will use the average historical Summer performance from Years 1, 2, and 3. In Year 5, the average historical Summer performance from Year 1 will be replaced by Year 4 and the cycle will continue to repeat year-over-year using the 3 most recent years of average historical Summer performance. Below are examples of how both BTMG and CPNode solar resources will be accredited.

BTMG

Year 1 → SAC_{BTMG} = Nameplate capacity * seasonal class credit * (1 + Transmission Losses)
→ SAC_{BTMG} = 10 * 50% * (1 + 5%)
→ SAC_{BTMG} = 5.25

Year 2 → SAC_{BTMG} = 10 * (65%) (1 + 5%)
→ SAC_{BTMG} = 6.8 (rounded to tenth decimal place)

Year 3 → SAC_{BTMG} = 10 * (70%) (1 + 5%)
→ SAC_{BTMG} = 7.4 (rounded to tenth decimal place)

CPNode

Year 1 → Total SAC_{CPNode} = Nameplate capacity * seasonal class credit

→ Total SAC_{CPNode} = 10 * (50%)
→ Total SAC_{CPNode} = 5.0

Year 2 → Total SAC_{CPNode} = 10 * (65%) = 6.5

Year 3 → Total SAC_{CPNode} = 10 * (70%) = 7.0

Example 2: New solar resource with at least 30 consecutive Summer days

In this example, the new solar resource has at least 30 consecutive Summer days of performance. Thus, the solar resource will not receive the solar class average for the initial Planning Year. In Year 1, the average historical Summer performance from Commercial Operation data will be used to determine the accredited amount. In Year 2, the resource will use the average historical Summer performance from Year 1 and 2. In Year 3, the resource will use the average historical Summer performance from Years 1, 2, and 3. In Year 4, the average historical Summer performance from Year 1 will be replaced by Year 4 and the cycle will continue to repeat year-over-year using the 3 most recent years of average historical Summer performance.

BTMG

Year 1 → SAC_{BTMG} = Nameplate capacity * seasonal class credit * (1+ Transmission Losses)
→ SAC_{BTMG} = 10 * (65%) * (1 + 5%)
→ SAC_{BTMG} = 6.8 (rounded to tenth decimal place)

Year 2 → SAC_{BTMG} = 10 * (70%) * (1 + 5%)
→ SAC_{BTMG} = 7.4 (rounded to tenth decimal place)

CPNode

Year 1 → Total SAC_{CPNode} = Nameplate capacity * seasonal class credit
→ Total SAC_{CPNode} = 10 * (65%)
→ Total SAC_{CPNode} = 6.5

Year 2 → Total SAC_{CPNode} = 10 * (70%)
→ Total SAC_{CPNode} = 7.0

Once the total SAC value for a resource has been determined, it is compared with the Interconnection Service assigned to that resource. Resources that are fully deliverable are eligible to convert all of their total SAC to ZRCs with no further action needed.

For resources that are not fully deliverable, having either partial or no deliverability, the following steps would be used:

1) MISO calculates a deliverability-adjusted capacity factor for the resource.

2) For SAC not considered convertible, the Market Participant may choose to obtain firm Transmission service in some level to convert some or all of the undeliverable SAC to Convertible. MISO supplies documentation to the MP on the MECT tool that can be used to determine the level of SAC that can be converted given some level of firm Transmission obtained.

3) Subsequently, the MP uses the Confirm SAC function to move the desired Convertible SAC amount to the Convert SAC MECT page. Once there, the associated firm Transmission information is entered after selecting the ERIS SAC value.

4) After MISO approval of the firm Transmission data that was entered by the MP, the SAC may then be converted to ZRCs for use in the PRA.

SAC is allocated by type of Interconnection Service (NRIS or ERIS with a TSR). SAC associated with ERIS may be converted into Zonal Resource Credits for use in the PRA with an approved Transmission Service Request.

Appendix X – Hybrid and Co-Located Resource Accreditation

This appendix describes the accreditation process for Hybrid Resources and Co-Located Resources. A Hybrid Resource is defined as a resource that is comprised of two or more separate Electric Facilities that share a single Point of Interconnection and that provides a single energy offer in the MISO DA/RT Energy Markets. A Co-Located Resource is defined as a resource that is comprised of two or more separate Electric Facilities that share a single Point of Interconnection where each separate Electric Facility provides separate energy offers in the MISO DA/RT Energy Markets.

Hybrid Resources and Co-Located Resources will be accredited in one of two phases depending on how much operating data is available. The Phase I – Sum of Parts approach will apply default class accreditation values for each separate Electric Facility comprising the Hybrid Resource or Co-Located Resource. The Phase II – Availability-based approach will consist of tracking the historic availability of each separate Electric Facility of the Hybrid Resource or Co-Located Resource. A Hybrid Resource or Co-Located can be Phase I for a Season and then get Phase II for a subsequent Season that it has operational data for. Once a Hybrid Resource begins receiving Phase II availability-based accreditation, the resource will continue to receive Phase II availability-based accreditation.

For Co-Located Resources, allocation of total Interconnection Service at the shared Point of Interconnection among the separate Electric Facilities must be provided to MISO Resource Adequacy staff by the incumbent Asset Owner, or the Market Participant(s) representing the incumbent Asset Owner, prior to conversion of Seasonal Accredited Capacity (SAC) to Zonal Resource Credits (ZRCs).

Phase I – Sum of Parts

Each Hybrid Resource or Co-Located Resource may be operating in very different ways from other Hybrid Resources or Co-Located Resources with a similar configuration depending on the goals of the resource owner and operator. Until historical operating data exists, default class accreditation values for each separate Electric Facility comprising the Hybrid Resource or Co-Located Resource will be applied. Co-Located Resource owners must inform MISO how the total Interconnection Service granted at the shared Point of Interconnection should be allocated among each separate Electric Facility for conversion purposes. Phase I accreditation will apply for each Season until a minimum of 30 consecutive historical days of operation for the corresponding Season have been observed.

For Phase I, Market Participants must submit a populated Non-GADS Performance Template to MISO through the MECT for each separate Electric Facility that includes the nameplate capacity (or registered maximum output from the Commercial Model) and resource type of each Electric Facility, unless the Electric Facility qualifies as a Schedule 53 resource.

Phase II – Availability-based

Phase II accreditation will apply after a Hybrid Resource or Co-Located Resource has sufficient operating history to determine a resource-specific seasonal accreditation value.

Availability is measured as historical net output (exception for ESR below) and will be determined in the following ways:

- For Hybrid Resources, the combined historical net output of each Electric Facility, provided via a single populated Non-GADS Performance Template.
- For Co-Located Resources, the separate historical net output of each Electric Facility, provided via several populated Non-GADS Performance Templates.
- For the ESR component of a Hybrid Resource or Co-Located Resource, availability for a given hour will be measured as the maximum of the net output or the output potential on that hour. Output potential should be determined as the minimum of the Hourly Equivalent Discharge Amount or the state of charge minus the Emergency Minimum Energy Storage Limit for a given hour.

Market Participants must submit Non-GADS Performance Templates to MISO through the MECT. In addition to historical operating performance, populated Non-GADS Performance Templates must include nameplate capacity (or registered maximum output from the Commercial Model) and resource type.

Appendix Y – SAC Calculations for Schedule 53 Resources

This appendix describes the process of calculating Seasonal Accredited Capacity (SAC) for Schedule 53 Resources.

1. Identification of Resource Adequacy Hours

Resource Adequacy (RA) Hours represent the periods of highest risk and greatest need during a Season and throughout the year. They include Emergency Declaration periods and the hours when the operating margin, a measure of available supply capacity above Demand and reserve requirements, is at its lowest. RA Hours are determined seasonally and at a subregional level (North/Central and South) based on emergency events, the tightest operating margin hours (65 hours per Season), and a maximum operating margin threshold established at 25 percent.

RA Hours will be used to determine each resources' availability for calculating its seasonal accreditation. The number of RA Hours in a Season can exceed the target when a high number of hours during declared system or subregional emergencies occurs.

Provisions also ensure Seasons have a minimum target number of RA Hours by supplementing any deficient hours with Annual Average Offered Capacity (AAOC) over all RA hours across the year. The RA Hours used for determining the AAOC (or AAOC Hours) are the hours with emergency events and the tightest 3 percent of operating margin hours below the 25% threshold for each year, up to 260 hours per year. The AAOC Hours are determined on a sub-regional (North/Central and South) basis. Not all AAOC Hours are RA hours.

1.1 **Definition and Identification of RA Hours**

RA Hours are defined over the three most recent historical years from September - August, based on declared MaxGen alert, warning and event hours supplemented by the tightest 3 percent of hours per Season where the realized operating margin for the region is at or below the threshold of 25 percent.

1.1.2 Hourly Operating Margin Calculation

The Operating Margin is determined using historical information to identify RA Hours and AAOC Hours within the three (3) most recent periods beginning September 1 and ending August 31.

We first express the power balance between load and supply, where:

$$Load = Thermal\ Resource\ Energy + Renewable\ Energy + Net\ Scheduled\ Interchange \quad (1)$$

$$Supply = Thermal\ Resource\ EmergencyMax + Renewable\ Energy + Net\ Scheduled\ Interchange - Operating\ Reserve \quad (2)$$

Substituting (1) into (2), we have

$$\begin{aligned} Margin(MW) = & [Thermal\ EmergencyMax + Renewable\ Energy + Net\ Scheduled\ Interchange\ (NSI)] \\ & - [Thermal\ Energy + Renewable\ Energy + Net\ Scheduled\ Interchange] \\ & - Operating\ Reserve \\ & = Thermal\ Resource\ EmergencyMax - Thermal\ Resource\ Energy - Operating\ Reserve \end{aligned}$$

The power balance between equation (1) and (2) suggests the renewable Energy and net-scheduled interchange have been implicitly reflected in the margin calculation but has no impact on the overall margin calculation used for RA hour identification as in the steps below.

By re-arranging the $Margin(MW)$ and broken down to online and offline components, we re-express the Operating Margin Equation as below

$$Operating\ Margin\ (\%)_j = \frac{Online\ margin\ (MW)_j + offline\ margin\ (12\ hour\ leadtime)(MW)_j}{Real\ Time\ (RT)Load\ (MW)_j}$$

Where:

$$Online\ margin\ (MW)_j = \sum_{unit\ i\ in\ region\ j} (EmergencyMax_i - EnergyMW_i - cleared\ operating\ reserve_i)$$

for all Resources that are online and under normal dispatch control; and

$$Offline\ margin\ (MW)_j = \sum_{unit\ i\ in\ region\ j} (EmergencyMax_i - cleared\ offline\ supplement\ reserve_i)$$

for Resources where all of the following is true: (i) Resource is Offline; (ii) its cold-start lead-time is less than or equal to 12 hours; and (iii) it is not on outage.

Load Modifying Resource (LMR), and Emergency Demand Response (EDR) are excluded in the Online margin (MW) and Offline margin (MW) calculations because they require emergency declarations in order to access.

1.1.2 Selection of RA Hours

Hours during which MaxGen declarations are in effect automatically become RA Hours, including all MaxGen Alert, Warning, or Event hours declared in each Season within each of the three (3) most recent September-August periods.

For non-MaxGen declaration hours in each of the 12 Seasons of the past three-year period, additional RA Hours with the tightest margin will be identified until reaching the (65 hours) for

each Season; if a Season already has more than 65 hours because of MaxGen declaration, this step will be skipped.

Finally, a maximum margin threshold is applied to exclude hours with an operating margin greater than 25 percent.

Going through the steps above, some Seasons will have more than 65 hours because of MaxGen declarations, while some other Seasons may have less than 65 hours if there are hours excluded based on the 25 percent maximum margin threshold criterion and a low number of hours with MaxGen declarations, reflecting underlying Demand, supply and weather conditions. The deficiency from the 65 target hours leads to the need for AAOC Hour as described in the next section.

Additionally, each individual resource will have its own set of RA hours that are dependent on outage exemptions and whether it was designated for Resource Adequacy Requirements (RAR) in previous year's seasonal auctions. Like the system-wide RA hours, if a resource has deficient RA hours in a Season, that resource's AAOC will be supplemented for the deficient hours.

Non-RAR resources are not subject to SAC calculation using seasonal RA and AAOC hours.

If the unit was designated as RAR within the 3-year lookback period, the following logic will apply.

- When a unit is RAR and has 60 days or more during the 3-year lookback period of that particular Season's operational data, for that Season SAC will be calculated with that historical operational data. Operating days that a unit was in full outage will be excluded from the statistics.
- If the unit has less than 60 days of data designated as a RAR for that Season over the 3-year lookback period they will receive Schedule 53 seasonal class average SAC accreditation. Operating days that a unit was in full outage will be excluded from the statistics.
- For resources that have a generation capacity change due to upgrades or seasonalization that had a non-zero offer historically, the RT EmerMax will be prorated based on the capacity change/ICAP% of the historical offers, capped at the new GVTC of the resource.
- For resources that have a generation increase due to upgrades or seasonalization, that have zero historical offer information, will receive Schedule 53 seasonal class average SAC accreditation for that Season

- In the case where a schedule 53 generator was derated due to transmission limitations imposed by the incumbent Transmission Operator, the MP can work with MISO to determine if any exemptions for those hours can be granted
- Exemption status for a unit's outage should be validated and resolved with MISO if needed, per timeline defined in BPM-008 (Business Manual -- Outage Operations)

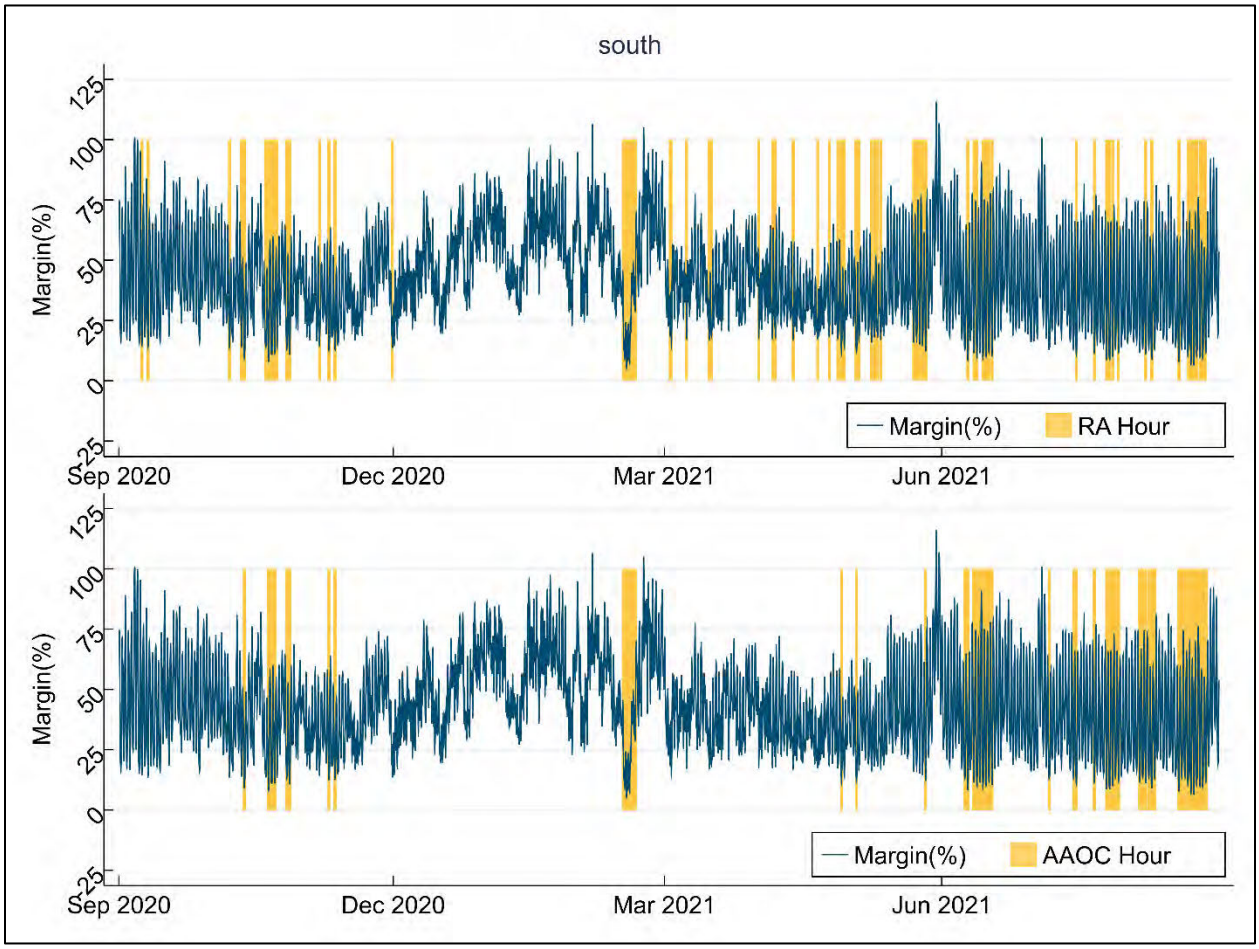
1.1.3 Selection of AAOC RA Hour

Hours where MaxGen declarations are in effect automatically become AAOC RA Hours, including all MaxGen Alert, Warning, or Event hours declared in each Season within the three (3) most recent periods.

For the rest of non-MaxGen declaration hours in each year of the past three-year periods, additional AAOC RA Hours with the tightest margin will be identified until reaching the (260 hours) for each year. For a unit to receive exemption for an AAOC hour they must have Tier 2 exemption during that hour.

1.1.4 Illustration of Selected RA Hour

The figure below, using South region as example, illustrates the variation of hourly Margin (%) between September 1, 2020, and August 31, 2021, and labels the selected RA Hour / AAOC Hour. In this example, there are 65 RA Hours identified in each of the four Seasons, hence the AAOC Hour will not be needed for backfilling any deficiency hour.



1.2 **Seasonal Accredited Capacity Calculation**

Resource Accreditation should reflect the anticipated capability and availability of Planning Resources during times when they are most needed. The following sections illustrate the two-tiered weighting structure to calculate Intermediate Seasonal Accredited Capacity (ISAC) reflecting general availability while emphasizing availability during times of greatest need. Each Resource will have its ISAC determined based on its Real-Time offered availability (Emergency Maximum Limit) during seasonal RA Hours (Tier 2) as described in Section 1.1 and Non-RA Hours (Tier 1).

1.2.1 Prepare Hourly Real-Time Offered Availability Dataset

The first step is to prepare the hourly Real-Time Offered Availability dataset for a Resource, including (1) hourly timestamp (EST); (2) offered Real-Time availability (EmerMax MW); (3) lead time(Start up time + Start up notification time) (in hours); (4) binary indicator if a resource is in outage from either the commit status or from records in Control Room Operations Window (CROW) Outage Scheduler; (5) binary identifier indicating if a Resource is online.; (6) ICAP (MW); and (7) binary indicator if a resource has received outage exemption.

Figure below provides a sample screenshot of the dataset, using a sample Resource located in Central/North region. If a Resource is in Derated status but not in outage, its offered availability already accounts for the impact of derates.

season	timeest	RT Offer EmerMax (MW)	Cold Leadtime (hours)	Outage Identifier (1=Out-of-Service)	Online Identifier (1=online)	ICAP	Outage Exemption Identifier (1=Exemption)
summer	2020-07-29 00:00:00	76	1	0		71.6	0
summer	2020-07-29 01:00:00	76	1	0		71.6	0
summer	2020-07-29 02:00:00	77	1	0		71.6	0
summer	2020-07-29 03:00:00	77	1	0		71.6	0
summer	2020-07-29 04:00:00	77	1	0		71.6	0
summer	2020-07-29 05:00:00	77	1	0		71.6	0
summer	2020-07-29 06:00:00	77	1	0		71.6	0
summer	2020-07-29 07:00:00	77	1	0	1	71.6	0
summer	2020-07-29 08:00:00	76	1	0	1	71.6	0
summer	2020-07-29 09:00:00	75	1	0	1	71.6	0
summer	2020-07-29 10:00:00	75	1	0	1	71.6	0
summer	2020-07-29 11:00:00	75	1	0	1	71.6	0
summer	2020-07-29 12:00:00	75	1	0	1	71.6	0
summer	2020-07-29 13:00:00	75	1	0	1	71.6	0
summer	2020-07-29 14:00:00	75	1	0	1	71.6	0
summer	2020-07-29 15:00:00	75	1	0	1	71.6	0
summer	2020-07-29 16:00:00	75	1	0	1	71.6	0
summer	2020-07-29 17:00:00	75	1	0	1	71.6	0
summer	2020-07-29 18:00:00	75	1	0	1	71.6	0
summer	2020-07-29 19:00:00	75	1	0	1	71.6	0
summer	2020-07-29 20:00:00	75	1	0	1	71.6	0
summer	2020-07-29 21:00:00	75	1	0	1	71.6	0
summer	2020-07-29 22:00:00	75	1	0	1	71.6	0
summer	2020-07-29 23:00:00	76	1	0	1	71.6	0

In sample data above, the outage indicator is set to 1 (outage) either if there is a valid full outage ticket in CROW or the unit was offered as outaged in real time for the specific hour. The online indicator is based on unit's control mode from ICCP data as described in 2.4.7 in BPM-031 (ICCP Data Requirement).

1.2.2 Prepare Calculation for Annual Average Offered Capacity (AAOC)

If a Resource does not have 65 RA hours in a Season, AAOC is needed for backfilling the availability during deficiency hours in later steps. To calculate AAOC, the RT Offer EmerMax data is paired with AAOC hours by timestamp. Availability (MW) during AAOC hour is then generated through these following steps:

(1) Set availability = Min (ICAP, Real-Time Offer EmerMax) during AAOC hour; this step caps RT Offer EmerMax at ICAP;

(2) Set availability = zero if a Resource is in outage (based on outage identifier) during AAOC Hour;

(3) Set availability = zero if a Resource is not online and not in outage and has lead time (Start up time + Start up notification time) greater than 24 hours during AAOC Hour.

(4) Set availability = NULL if a Resource has been granted outage exemption during AAOC Hour.

Figure below shows the sample dataset fragment after generating the availability (MW) during AAOC hour through the steps described above.

season	timeest	RT Offer EmerMax (MW)	Cold Leadtime (hours)	Outage Identifier (1=Out-of-Service)	Online Identifier (1=online)	ICAP	Outage Exemption Identifier (1=Exemption)	Annual RA Hour Identifier (Classic)	Availability in AAOC Hour (MW) after Outage Exemption
summer	2020-07-29 00:00:00	76	1	0		71.6	0		
summer	2020-07-29 01:00:00	76	1	0		71.6	0		
summer	2020-07-29 02:00:00	77	1	0		71.6	0		
summer	2020-07-29 03:00:00	77	1	0		71.6	0		
summer	2020-07-29 04:00:00	77	1	0		71.6	0		
summer	2020-07-29 05:00:00	77	1	0		71.6	0		
summer	2020-07-29 06:00:00	77	1	0		71.6	0		
summer	2020-07-29 07:00:00	77	1	0	1	71.6	0		
summer	2020-07-29 08:00:00	76	1	0	1	71.6	0		
summer	2020-07-29 09:00:00	75	1	0	1	71.6	0		
summer	2020-07-29 10:00:00	75	1	0	1	71.6	0		
summer	2020-07-29 11:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 12:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 13:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 14:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 15:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 16:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 17:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 18:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 19:00:00	75	1	0	1	71.6	0	1	71.6
summer	2020-07-29 20:00:00	75	1	0	1	71.6	0		
summer	2020-07-29 21:00:00	75	1	0	1	71.6	0		
summer	2020-07-29 22:00:00	75	1	0	1	71.6	0		
summer	2020-07-29 23:00:00	76	1	0	1	71.6	0		

1.2.3 Prepare Calculation for Intermediate Seasonal Accredited Capacity (ISAC)

To calculate SAC, the RT Offer EmerMax data is paired with RA Hour by timestamp. Availability (MW) during RA Hour is then generated through these following steps:

For availability during Tier 1 Non-RA Hour:

(1) Set availability = Min (ICAP, Real-Time Offer EmerMax) during Tier 1 Non-RA hour; this step caps RT Offer at ICAP;

(2) Set availability = zero if a Resource is in outage (based on outage identifier) during Tier 1 Non-RA Hour;

(3) Set availability = NULL if a Resource has been granted outage exemption during Tier 1 Non-RA Hour.

For availability during Tier 2 RA Hour:

(1) Set availability = Min (ICAP, Real-Time Offer EmerMax) during Tier 2 RA hour; this step caps RT Offer at ICAP;

(2) Set availability = zero if a Resource is in outage (based on outage identifier) during Tier 2 RA Hour;

(3) Set availability = zero if a Resource is not online and not in out-of-service outage and has lead time (start up time + Start up notification time) greater than 24 hours during Tier 2 RA Hour;

(4) Set availability = NULL if a Resource has been granted outage exemption during Tier 2 RA Hour.

Figure below shows the sample dataset fragment after generating the availability (MW) during seasonal Tier 1 and Tier 2 RA hour through the steps described above.

season	timeest	RT Offer EmerMax (MW)	Cold Leadtime (hours)	Outage Identifier (1=Out-of-Service)	Online Identifier (1=online)	ICAP	Outage Exemption Identifier (1=Exemption)	Seasonal RA Hour Identifier (Classic)	Availability in Seasonal Tier 1 (non-RA) Hour (MW) after Outage Exemption	Availability in Seasonal Tier 2 RA Hour (MW) after Outage Exemption
summer	2020-07-29 00:00:00	76	1	0		71.6	0		71.6	
summer	2020-07-29 01:00:00	76	1	0		71.6	0		71.6	
summer	2020-07-29 02:00:00	77	1	0		71.6	0		71.6	
summer	2020-07-29 03:00:00	77	1	0		71.6	0		71.6	
summer	2020-07-29 04:00:00	77	1	0		71.6	0		71.6	
summer	2020-07-29 05:00:00	77	1	0		71.6	0		71.6	
summer	2020-07-29 06:00:00	77	1	0		71.6	0		71.6	
summer	2020-07-29 07:00:00	77	1	0	1	71.6	0		71.6	
summer	2020-07-29 08:00:00	76	1	0	1	71.6	0		71.6	
summer	2020-07-29 09:00:00	75	1	0	1	71.6	0		71.6	
summer	2020-07-29 10:00:00	75	1	0	1	71.6	0		71.6	
summer	2020-07-29 11:00:00	75	1	0	1	71.6	0		71.6	
summer	2020-07-29 12:00:00	75	1	0	1	71.6	0	1		71.6
summer	2020-07-29 13:00:00	75	1	0	1	71.6	0	1		71.6
summer	2020-07-29 14:00:00	75	1	0	1	71.6	0	1		71.6
summer	2020-07-29 15:00:00	75	1	0	1	71.6	0	1		71.6
summer	2020-07-29 16:00:00	75	1	0	1	71.6	0	1		71.6
summer	2020-07-29 17:00:00	75	1	0	1	71.6	0	1		71.6
summer	2020-07-29 18:00:00	75	1	0	1	71.6	0	1		71.6
summer	2020-07-29 19:00:00	75	1	0	1	71.6	0		71.6	
summer	2020-07-29 20:00:00	75	1	0	1	71.6	0		71.6	
summer	2020-07-29 21:00:00	75	1	0	1	71.6	0		71.6	
summer	2020-07-29 22:00:00	75	1	0	1	71.6	0		71.6	
summer	2020-07-29 23:00:00	76	1	0	1	71.6	0		71.6	

1.2.4 Calculation of Annual Average Offered Capacity (AAOC)

For each of the past three years, the AAOC is calculated as the sum of availability over AAOC hours, divided by the total number of AAOC hours (excluding outage exemption hours) in each year, as shown in the table below for a sample resource.

CY	# AAOC Hours	Sum of Availability (MW) over AAOC Hours	Annual Average Offered Capacity (MW)
Formula Key	A	B	B/A
CY17Sept18Aug	260	15,990	62
CY18Sept19Aug	260	17,444	67
CY19Sept20Aug	243	17,171	71

1.2.5 Calculation of Intermediate Seasonal Accredited Capacity (ISAC)

For Non-RA Hours (Tier 1), Intermediate Seasonal Accredited Capacity is calculated as the sum of availability over seasonal Tier 1 Non-RA hours, divided by the total number of seasonal Tier 1 Non-RA hours across the past three years.

CY	Season	# of Tier 1 non-RA Hours after outage exemption	Sum of Availability (MW) over Tier 1 non-RA Hours after outage exemption	Tier 1 3-year average ISAC after outage exemption
Formula Key		A	B	C=SUM(B1, B2, B3)/SUM(A1, A2, A3)
CY17Sept18Aug	fall	2,119	3,509	
CY18Sept19Aug	fall	2,119	128,215	44
CY19Sept20Aug	fall	1,731	129,457	
CY17Sept18Aug	winter	2,095	131,376	
CY18Sept19Aug	winter	2,095	89,229	61
CY19Sept20Aug	winter	2,091	163,989	
CY17Sept18Aug	spring	2,143	147,505	
CY18Sept19Aug	spring	2,142	151,993	72
CY19Sept20Aug	spring	2,192	164,796	
CY17Sept18Aug	summer	2,143	154,731	
CY18Sept19Aug	summer	2,143	149,724	71
CY19Sept20Aug	summer	2,143	154,375	

For RA Hour (Tier 2), its Intermediate Seasonal Accredited Capacity is calculated as the sum of availability over seasonal RA hours and AAOC multiplied by the deficient RA hours, then averaged over total number of Tier 2 RA hours across the past three years. A particular Season will be excluded from a unit's tier 1 and tier 2 ISAC calculation if either condition is met: 1) a unit has not been designated as RAR for the Season or 2) it has not been offering into Real-Time market due to an exempt outage for the whole Season.

CY	Season	# of Tier 2 RA Hours after outage exemption	Sum of Availability (MW) over Tier 2 RA Hours after outage exemption	Deficient # of Tier 2 hours	Annual Average Offered Capacity (MW) after outage exemption	Sum of Availability (MW) over Deficient hours	Sum of total Availability (MW)	Sum of Tier 2 hours	Tier 2 3-year average ISAC after outage exemption
Formula Key		A	B	C = Max((65 hours-A), 0)	D	E=C*D	F=B+E	G=A+C	H=SUM(F1, F2, F3)/SUM(G1, G2, G3)
CY17Sept18Aug	fall	65	0	0	62	0	0	65	
CY18Sept19Aug	fall	65	4,788	0	67	0	4,788	65	47
CY19Sept20Aug	fall	31	1,949	34	71	2,402	4,352	65	
CY17Sept18Aug	winter	65	5,348	0	62	0	5,348	65	
CY18Sept19Aug	winter	65	3,274	0	67	0	3,274	65	68
CY19Sept20Aug	winter	4	321	61	71	4,310	4,631	65	
CY17Sept18Aug	spring	65	4,784	0	62	0	4,784	65	
CY18Sept19Aug	spring	55	3,256	10	67	671	3,927	65	68
CY19Sept20Aug	spring	16	1,178	49	71	3,462	4,640	65	
CY17Sept18Aug	summer	65	4,683	0	62	0	4,683	65	
CY18Sept19Aug	summer	65	4,678	0	67	0	4,678	65	72
CY19Sept20Aug	summer	65	4,674	0	71	0	4,674	65	

1.2.6 Tier Weighting of ISAC

The final Intermediate Seasonal Accredited Capacity (ISAC) value is the weighted averaged over its values from two tiers as calculated from steps above. The corresponding tier weightings are:

	Weighting by Planning Year		
Tier	2023- 2024 Planning Year	2024-2025 Planning Year	2025-2026 Planning Year and beyond
$ISAC_{Tier1\_weighting}$	40%	30%	20%
$ISAC_{Tier2\_weighting}$	60%	70%	80%

$$ISAC = ISAC_{Tier\ 1\ MW} \times ISAC_{Tier\ 1\ weighting} + ISAC_{Tier\ 2\ MW} \times ISAC_{Tier\ 2\ weighting}$$

The table below illustrates the ISAC of a sample resource.

WEIGHTED ISAC by SEASON with outage exemption	Season	ISAC
	fall	46
	winter	67
	spring	69
	summer	72

1.2.7 Final conversion to SAC

Lastly, the ISAC is converted back to SAC in UCAP term using the formula and as illustrated in the sample table below. The Conversion Ratio is calculated for each Season on a system-wide basis for all Schedule 53 resources.

$$SAC = ISAC \times Conversion\ Ratio_{UCAP/ISAC}$$

Conversion Ratio UCAP / ISAC	Season	SAC
1.1754	fall	54
1.131	winter	75
1.152	spring	80
1.068	summer	77

The following rules are applied for determining units to be included/excluded in ratio calculations.

1. Only resources are included in both LOLE study and SAC calculations for the same Season of planning year are included in the UCAP/ISAC ratio calculation.2. Resources that are granted with a class average for one or multiple Seasons, are not included in ratio calculation for the Season(s)

1.2.8 SAC calculation for Combined Cycle (CC)units

Due to complicated nature of modeling and market participation options for combined cycle units, MISO will calculate their ISAC/SAC values based on how they are modeled and historically been offered into the Real-Time market, and how the combined cycle units submit their test capacity (GVTC) data in MISO GADS data:

1. If the owner of combined cycle unit submits GVTC data on the parent CP node only, MISO will calculate the SAC value on the parent node, by combining the Real-Time children's offer data if needed and capped at the latest GVTC. MISO will only provide planned outage exemptions for the SAC calculation, if all of the children units are fully outaged with valid exempt outage requests.

2.If the owner of combined cycle unit submits GVTC data on the children's CP nodes, or submits GVTC data on the parent node, but with specified % split of each children node, MISO will calculate SAC values for each children CP node. MISO may need to split the Real-Time offer (Emergency Max) based on the % ratios of all the children's GVTC data, if needed. In this scenario, each children's exempt outage will be reflected in their own SAC calculations.

1.2.9 SAC calculation for Jointly Owned Units (JOU)

Jointly Owned Units (JOUs) SAC values will be calculated the same way as regular units as long as the owners submit their separate GVTC data in the MISO GADS system. For units that have experienced ownership and/or share percentage changes within the last 3 years where Real-Time offer data is used, MISO may need to combine all the owner's Real-Time offers, capped by their total GVTC and then split again based on the latest GVTC ratios among ownerships before calculating each owner's SAC values.

1.3 **Class Average based SAC calculation**

New Schedule 53 Resources or existing Resources that do not have at least 60 days of Real-Time offered availability when designated for RAR over the last three (3) years for each Season (Summer, Fall, Winter, Spring) will have a SAC based on the class average SAC to ICAP Ratio for its Resource type. MISO will calculate Schedule 53 class averages based on existing GADS fuel type categories from the existing MISO Schedule 53 fleet.

Per MISO's discretion and agreement with the resource owner, MISO may grant the unit class average, if a unit's operation and offer history no longer represents its future economical and physical characteristics.

Class averages (% values) are calculated based on units with sufficient Real-Time offer in each resource type by dividing their total seasonal ISAC values divided by total effective ICAP (lesser of GVTC or interconnection service):

$$Class\ Average\ \%_{type\ of\ resource} = \sum_{type\ of\ resource} ISAC \Big/ \sum_{type\ of\ resource} Effective\ ICAP$$

For units whose SAC is calculated based on a class average, their class average % is applied to the unit's ICAP (lesser of GVTC or Interconnection Service) to determine the ISAC. The UCAP/ISAC ratio per Season will then be applied to identify the final SAC for the Season

1.4 SAC conversion to ZRC

1.4.1 Allocate Total SAC into NRIS SAC and ERIS SAC based on Interconnection Service:

Schedule 53 Resource's Total SAC is allocated into NRIS SAC and ERIS SAC based upon its type of Interconnection Service.

$$Total\ SAC = NRIS\ SAC + ERIS\ SAC$$

To the extent the Planning Resource has Network Resource Interconnection Service (NRIS) or was determined to be aggregate deliverable through the market transition deliverability test, then that quantity will be allocated first to calculate the NRIS SAC as defined in Module E 69A.4.5

$$NRIS\ SAC = \min(NRIS, ICAP) \times \frac{Total\ SAC}{ICAP}$$

The remaining balance of Total SAC is allocated to ERIS SAC with following formula:

$$ERIS\ SAC = \max\big(0, (ICAP - NRIS)\big) \times \frac{Total\ SAC}{ICAP}$$

1.4.2 Eligibility of NRIS SAC and ERIS SAC Conversion into seasonal Zonal Resource Credits

The NRIS SAC represents capacity in MW that is eligible to be converted into seasonal Zonal Resource Credits.

In determining the amount of ERIS SAC eligible for conversion into seasonal ZRCs, the deliverability of any ERIS must be determined prior to ERIS SAC conversion. ERIS must be paired with firm Transmission Service that covers the entire Season to be considered deliverable. NRIS is automatically considered deliverable and does not require an additional Transmission Service Request. The full amount of ERIS SAC can be converted to ZRCs if the resource is fully deliverable to its ICAP amount.

Total SAC which can be converted into seasonal ZRCs are the summation of the Planning Resource's NRIS SAC plus the lesser of the resource's ERIS with firm Transmission Service. .

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Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-29
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-30

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 135
Holtec News Release

Holtec Receives Coveted “Tier 1 First Mover Award” from the USDOE to Accelerate Deployment of its Dual-Unit SMR-300 Plant at the Company’s Palisades Energy Site

- Holtec Highlights (https://holtecinternational.com/category/holtec-highlights/)
  - 2025 (https://holtecinternational.com/2025/)
  - 2024 (https://holtecinternational.com/2024/)
  - 2023 (https://holtecinternational.com/2023/)
  - 2022 (https://holtecinternational.com/2022/)
  - 2021 (https://holtecinternational.com/2021/)
  - 2020 (https://holtecinternational.com/2020/)
  - 2019 (https://holtecinternational.com/2019/)
  - 2018 (https://holtecinternational.com/2018/)
  - 2017 (https://holtecinternational.com/2017/)
  - 2016 (https://holtecinternational.com/2016/)
  - 2015 (https://holtecinternational.com/2015/)
  - 2014 (https://holtecinternational.com/2014/)
  - 2013 (https://holtecinternational.com/2013/)
  - 2012 (https://holtecinternational.com/2012/)
  - 2011 (https://holtecinternational.com/2011/)
- Videos (https://holtecinternational.com/news/videos/)

December 2, 2025

Camden, NJ, December 2, 2025: We are delighted and honored to have been selected as a recipient of the U.S. Department of Energy's Tier 1 "First Mover Team Support" award under the U.S. Government's Generation III+ Small Modular Reactor (SMR) Pathway to Deployment Program. The award, valued at $400 million, will catalyze the first-of-a-kind (FOAK) deployment of Holtec's dual-unit SMR-300 plant at the Company's Palisades Energy site where a formerly shuttered 805-MWe PWR is poised for imminent restart with the support of a DOE loan. Fittingly, the twin-unit SMR-300 plant has been named *PIONEER 1&2*, which captures its trailblazing mission to spearhead the rise of the SMR industry in the U.S. and the world. This FOAK project, which will add 680-MWe in a dual unit (340 MWe per unit) configuration, is envisaged to be built by Holtec with construction financing from the DOE's Loan Programs Office. With the financial pathway secured, we look with guarded confidence to implement our "*Mission 2030,*"which contemplates the Pioneer reactors being brought online in the first years of the 2030s.



Rendering of the first two Holtec SMR-300 units at the Palisades Energy site in Covert, Michigan.

As part of the program, DOE will provide milestone-based cost-share support that is intended to advance licensing, pre-construction, and supply-chain mobilization for the Palisades SMR-300 project. Holtec's proposal includes a multi-site deployment pathway that establishes a repeatable, fleet-scale model — a core requirement of the Tier 1 program intended to drive down costs and shorten construction durations through standardization and manufacturing efficiency. The DOE's support is an essential enabler of the Palisades SMR-300 project, moving it from development to deployment by building on the government's prior support for Holtec's SMR technology under the 2020 DOE Advanced Reactor Demonstration Program (ARDP) *Risk Reduction for Future Demonstrations* to support commercial readiness.

"Holtec realizes the future of nuclear energy as a source of reliable baseload electricity to power the economy of the future is realized only if we, in the industry, make the reactors predictably cost competitive. With a well-exercised and proven supply chain, a world-class (exclusive) alliance partner, Hyundai E&C, and the plant design marinated with four decades of practical corporate experience, we consider it our duty to lead the industry in building, owning, and operating the first SMR-300 plant in the United States. We are energized by DOE's confidence in our SMR-300 reactor, which we view as validation of our 14-year quest to develop a walk-away-safe and cost-competitive nuclear reactor. This grant positions Holtec to accelerate deployment of a standardized SMR-300 fleet that strengthens U.S. energy security and grid resilience and will further bolster Holtec as one of the largest U.S. exporters of nuclear equipment," said Dr. Kris Singh, CEO and Executive Chairman of Holtec International.

Holtec has repeatedly demonstrated its peerless execution capacity for nuclear projects over the past four decades, both domestically and abroad. From mechanical upgrades of nuclear plants to spent fuel management facilities to the ownership and decommissioning of nuclear power plants, Holtec has built a reputation for turnkey delivery. The Palisades restart project, which is the world's first restart of a retired nuclear plant, is due to be synchronized with the grid early next year, months ahead of the committed schedule and substantially below the allotted budget, provides contemporary evidence of our execution credentials.

Finally, we applaud the restart program for having created an operational platform, an operator and maintenance staff training pipeline, and a "can-do" nuclear project environment that is expected to have a salutary effect on the accelerated deployment of the SMR-300 fleet. In recognition of the importance of this SMR project to the Company, our President, Kelly Trice, who has shepherded the Palisades restart program since its inception, will also helm the Palisades SMR-300 project.

DOWNLOAD (HTTPS://HOLTECINTERNATIONAL.COM/WP-CONTENT/UPLOADS/2025/12/HH-40.24.PDF)

TAGS: PALISADES (HTTPS://HOLTECINTERNATIONAL.COM/TAG/PALISADES/), SMR (HTTPS://HOLTECINTERNATIONAL.COM/TAG/SMR/)

← Previous Post
New Fuel Arrives at Palisades to Power Its Imminent Restart (https://holtecinternational.com/hh-40-22/)

Holtec International's Companies, Divisions & Affiliates

HOLTECASIA

SMR

HOLTEC POWER DIVISION DE MEXICO

HOLT UKRA

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(https://www.youtube.com/channel/UC76KA6aBJ3lYmbsc5uSBXaw)

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Exhibit 136
Utility Dive Article on Palisades Plant

UTILITYDIVE

Palisades becomes first decommissioned US nuclear plant to reach ‘operations’ status

The plant still requires extensive work before it can resume generating electricity, however, owner Holtec International said.

Published Aug. 28, 2025



Meris Lutz
Senior Editor

Crews reinstall equipment at the Palisades power plant. Courtesy of Holtec International

The Palisades power plant in Covert Township, Michigan, on Aug. 25 became the first decommissioned U.S. nuclear plant to officially transition to “operations” status, owner Holtec International said in a statement.

The plant is not yet generating electricity; the company said the plant still requires extensive work, including reassembling the main generator and turbine.

Nevertheless, Holtec celebrated the “milestone” in its efforts to restart the plant, which it said will produce more than 800 MW. The plant’s new status follows its receipt of key approvals by the Nuclear Regulatory Commission last month.

“With this transition, Palisades is now authorized to receive nuclear fuel and restart the plant once allowable conditions are met,” the company said. “Beyond strengthening Michigan’s energy security, this achievement signals a historic first for the nuclear industry and reinforces the essential role of nuclear power in America’s energy future.”

Palisades began operations in 1971 and was decommissioned by Entergy in 2022. Soon after, Holtec acquired it and announced in 2023 its intention to pursue restarting it.

Holtec did not give a timeline for completion. It added that the plant’s emergency plan is in place, positioning Palisades “squarely in the final phase of restart preparations, as inspections, testing, and maintenance continue under rigorous independent federal oversight.”

The company is also planning to build a new small modular reactor on the same site “by the beginning of the next decade.”

Beyond Nuclear, a nonprofit that opposes the plant’s revival, issued a statement condemning its progress toward restarting.

“Holtec’s Palisades zombie reactor restart scheme is not only unprecedented, but also unneeded, insanely expensive for taxpayers and ratepayers, and very risky for health, safety, security, and the environment,” Kevin Kamps, the group’s radioactive waste specialist, said in a statement. “Because so much is at stake, we will continue to resist Holtec’s Palisades restart.”

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Exhibit 137
R Street Institute Commentary: *DOE "Zombies" Are Eating Competitive Power Markets*

REAL SOLUTIONS

Low-Energy Fridays: DOE "Zombies" Are Eating Competitive Power Markets

BY MICHAEL GIBERSON

ISSUES: ELECTRICITY POLICY, ENERGY AND ENVIRONMENT

NOV 13, 2025

This past May, the U.S. Department of Energy (DOE) used emergency authority to stop two scheduled power plant retirements. As we explained in July, these emergency orders are not a good way to boost grid reliability. That's not the only problem, though—the DOE's emergency orders also threaten to undermine competition in regional power markets.

The case invoked Section 202(c) of the Federal Power Act, which limits most orders to just 90 days. The DOE used this law to block the coal-fired J.H. Campbell Power Plant in Michigan and two units at the gas- and oil-fired Eddystone Generation Station in Pennsylvania from retiring. When those 90-day orders expired in August, the DOE issued new orders to keep the plants online. When these orders expire later in November, the DOE is expected to order the plants to stay online for *another* 90 days. Both currently operate with a safety net: If they lose money, the law makes area consumers cover those losses. And with losses covered no matter what, the plants have little reason to run efficiently. The result isn't grid reliability—it's creeping zombification of the market.

Markets require profits *and* losses to steer investment where it's needed (and away from where it's not). When a unit can't cover its costs at market prices, it should retire. When older, inefficient plants exit, space opens on the grid and in the market for better resources to jump in. Prices may initially rise, but consumers benefit in the end as competition grinds down average costs. Serial "emergency" orders break the economic feedback loop and undermine competitive forces.

The DOE's decision to keep two fossil-fueled power plants running raised speculation that the administration would block any fossil-fueled plant from retirement. However, a New Hampshire coal unit retired in October without federal intervention. That's good, because a plant that doesn't contribute to reliability and energy supplies at a competitive price *should* retire. But the lack of clear policy heightens uncertainty.

The economic damage shows up in three places:

- **Crowding out.** When zombie power plants are ordered to stay in the market, customers are stuck with the bill from any losses. Market revenues that would support efficient resources get skimmed by units the market has already rejected. The effect is subtle but

Privacy - Terms

important: Energy market prices flatten, clean and firm resources see less upside in tight hours, and generation turnover slows.

- **Planning.** Reliability planning depends on credible schedules—retirements that can be believed, new power plants that can be counted, and rules that don't change unnecessarily. A plant yo-yoing between "retired," "ordered to run," and "maybe extended" in 90-day increments can't fit into long-run reliability plans.

- **Policy-driven uncertainty.** States and stakeholders are suing the DOE over the emergency orders because the law is being employed in a manner different from what Congress intended. The DOE has not articulated a clear policy for how they will use their authority in the future, which leaves plant owners and potential investors in the dark.

Emergency orders do have their place. If a hurricane hits, fuel freezes, or a wildfire takes out a major power line, use 202(c) for the days or weeks necessary and then stand down. Utilities regularly ask for these emergency orders when they need them. The difference with zombie plant orders is that neither the plant owners nor the grid operators responsible for reliability in their regions requested them.

Nothing in this discussion denies reality—demand for electricity is rising, interconnection queues are clogged, and grid operators face tough winters and hot summers. The way forward is in policies that make better use of the existing grid, drive economical additions to transmission infrastructure, and let market forces drive power plant entry *and* exit. Competitive power markets are not responsible for rising electricity rates; in fact, a recent study pointed to increased spending on transmission and distribution wires as key factors in driving up customer rates.

Should the DOE continue to undermine market competition, consumers may get hit with the double-whammy of rising energy costs and rising infrastructure spending. Zombification of the electricity industry is no way to support a reliable, efficient power system.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-29
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-30

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 138
MISO Fall 2025 Operations Report

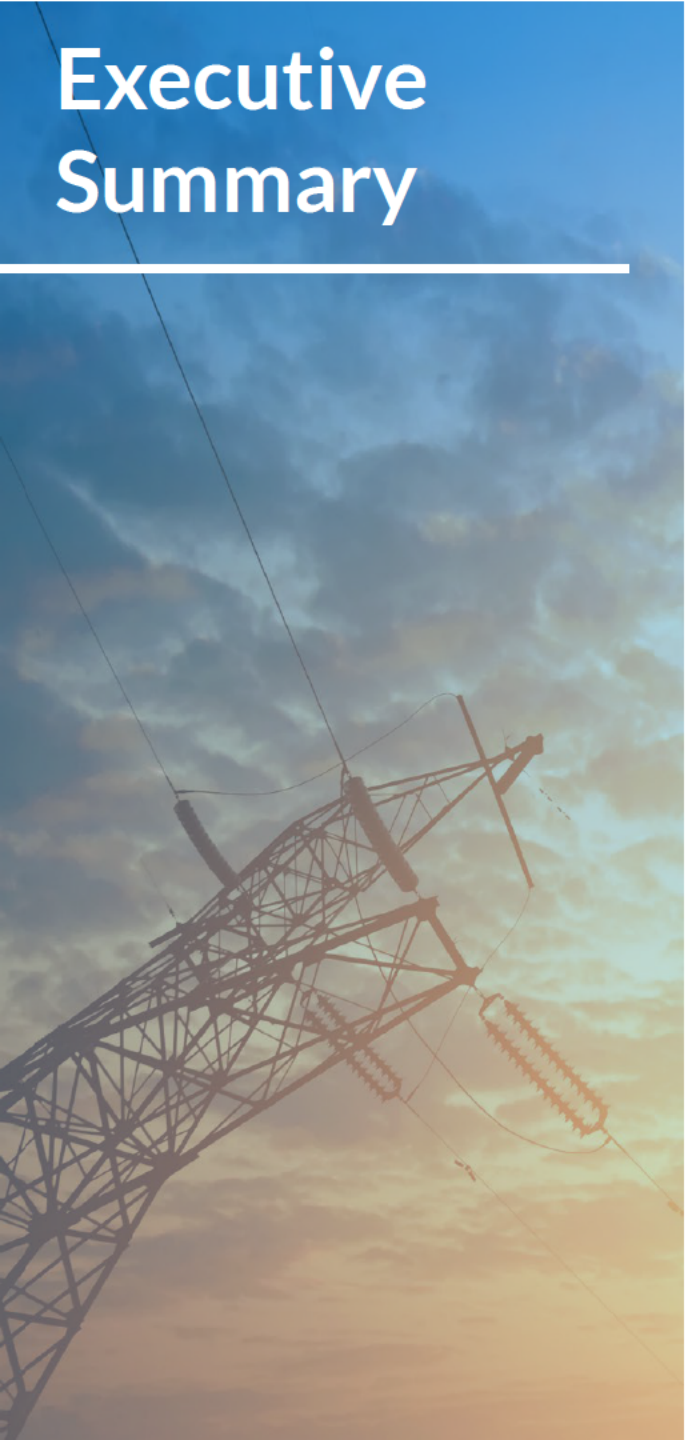


Operations Report

Markets Committee of the Board of Directors

December 9, 2025

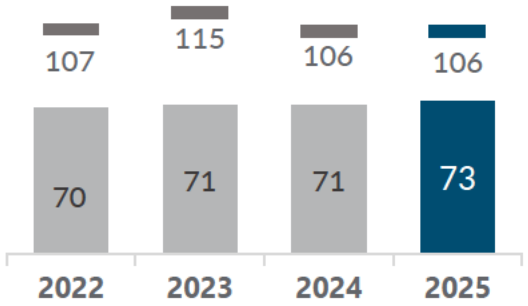
Executive Summary



- MISO's market and operations performed as expected during a mild fall.
- MISO is continually working to review and improve its Operational Risk Model, which will be used this winter to position operations in advance of challenging conditions, helping enable efficient reliability.
- Winter preparedness activities include training and drills for MISO and its members to practice for various conditions.

Reliability, markets and operational functions performed as expected this fall

AVERAGE AND PEAK LOAD (GW)



SYSTEMWIDE PEAK

106 GW

September 16

Fall Forecasted Peak: 110 GW

SOLAR PEAK

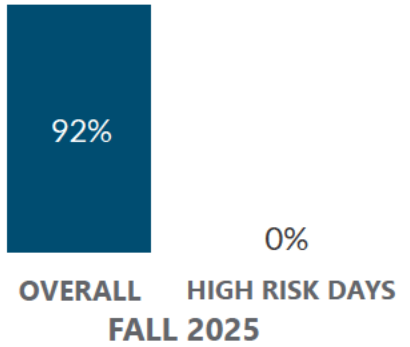
14.5 GW

September 7

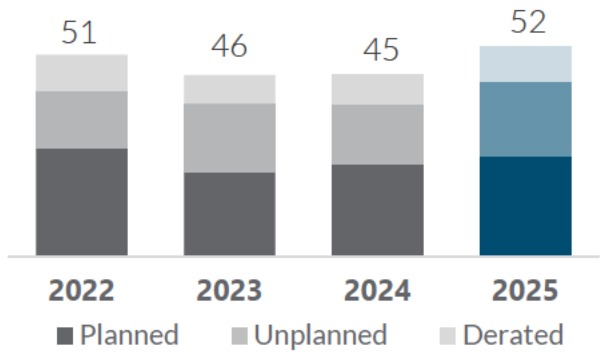
ACTUAL HIGH-RISK DAYS

6

RISK PREDICTION ACCURACY



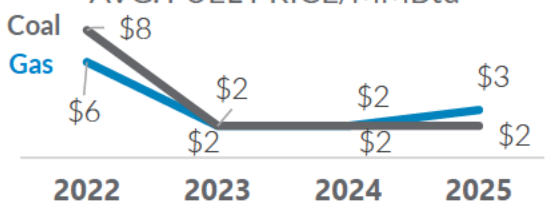
AVERAGE DAILY GENERATION OUTAGES (GW)



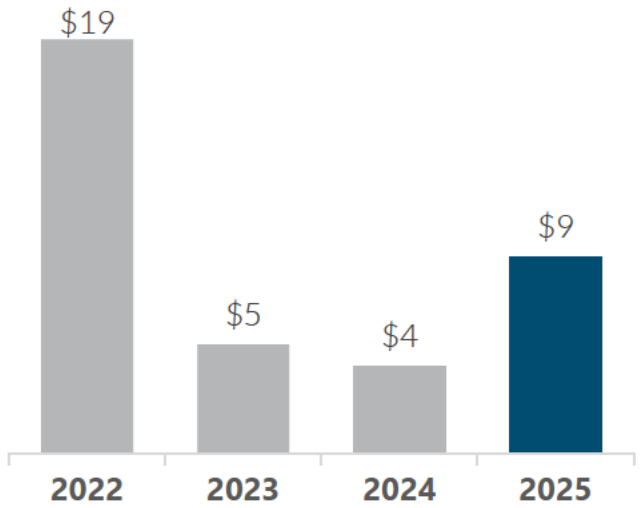
REAL-TIME LMP



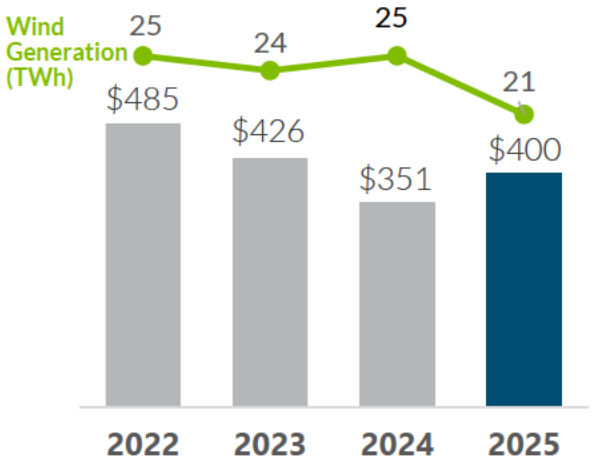
AVG. FUEL PRICE/MMBtu



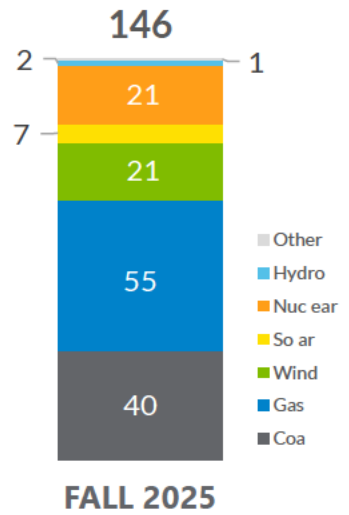
REAL-TIME UPLIFT* PAYMENTS ($M)



REAL-TIME CONGESTION ($M)**



ENERGY FUEL MIX (TWh)



Data shown for fall (September-November) as of 11/23/2025. Some November data not yet available.
Uplift is also known as revenue sufficiency guarantee (RSG); uplift values may change due to resettlement
Real-time congestion cost includes external constraints

MISO's Operational Risk Platform aids in unit commitment management through dynamic reserve products, and will continue to be impactful with planned maturity

OPERATIONAL RISK PLATFORM

MISO's dynamic Short-Term Reserves are set using a machine learning model that is focused on daily sufficiency with plans for maturity and expansion

TODAY

- ✓ Securing more reserves on the system on High-Risk days based on peak hour
- ✓ Informing operational situational awareness and decision making

FUTURE

- Management of additional reserve products
- Reserve requirements based on hourly predictions
- More robust inputs
- Automation

UNIT COMMITMENT EFFICIENCY IMPROVEMENTS

- **Unit Commitment:** Additional investment in Look-Ahead Commitment enhancements and process improvements
- **Reserve Planning:** Dynamic requirements through our Operational Risk Platform
- **Congestion Management:** Continue to improve congestion forecasting and work with stakeholders to address forced outage rates

STI Performance

Metric	YTD Performance
MARKET EFFICIENCY	
Unit Commitment Efficiency	●
Market Funding Efficiency	■
RELIABLITY	
Reliability Control	▼

▼ *Below Threshold* ■ *Threshold* ● *Target* ▲ *Excellent*

STI: Short-Term Incentive

Monthly Operational Metrics

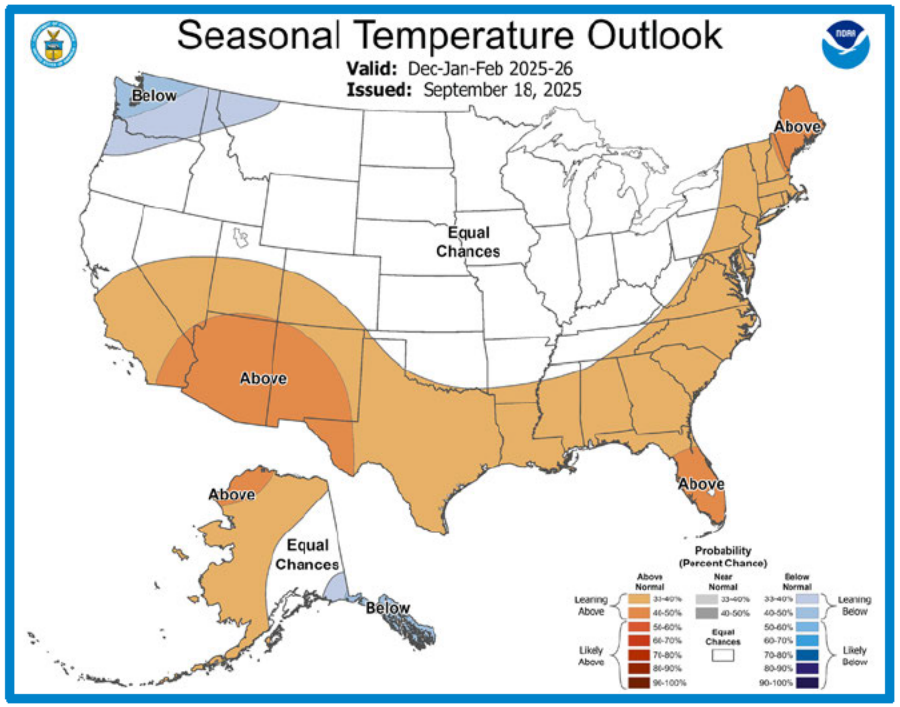
Metric	Oct 2025	Sept 2025	Aug 2025	July 2025	Metric	Oct 2025	Sept 2025	Aug 2025	July 2025
OPERATIONAL EXCELLENCE									
Control Performance – BAAL	●	●	●	●	Control Performance – CPS1 and CPS1 12-month rolling	●	●	●	●
Price Deviation	●	▼	●	▼	Real-Time Obligation fulfilled by Day-Ahead Supply at the Peak Hour	●	●	●	●
Monthly Average Gross Virtual Profitability	●	●	●	●	Day-Ahead Wind Generation Forecast Error	●	●	●	●
FTR Funding	●	●	●	●	Day-Ahead Solar Generation Forecast Error	●	●	●	●
RSG per MWh to Energy Price	■	●	●	●	Tie Line Error	●	●	●	●
Day-Ahead Mid-Term Load Forecast	●	●	●	●	ARS Deployment	●	●	●	●
Short-Term Load Forecast	●	●	●	●					
CUSTOMER SERVICE									
System Impact Study Performance	●	●	●	●	Settlement Disputes	●	●	●	●

● *Expected* ■ *Concern/Monitor* ▼ *Review*

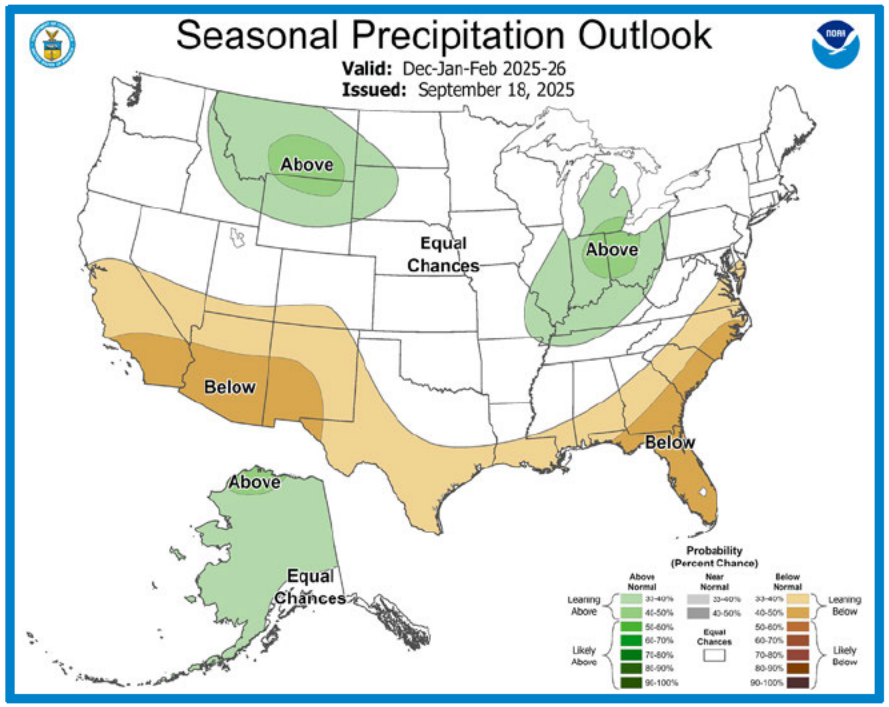
CLICK HERE to see MISO's monthly Operations Reports

MISO and its members evaluate anticipated risks for the winter and prepare for expected challenges, including drills for all steps of the emergency procedures

WINTER 2025-26 WEATHER PROJECTIONS



More variability in temperature is expected in the North and Central regions, while the South is anticipated to be above average



Above-normal precipitation is forecast for the Great Lakes region and drier along the Gulf Coast

WINTER PREPARATIONS

- Winter readiness workshops
- FERC/NERC winter recommendations
- Year-round operator training on normal and abnormal conditions
- Emergency procedure drills with member company operators
- Continuous improvement of processes and procedures

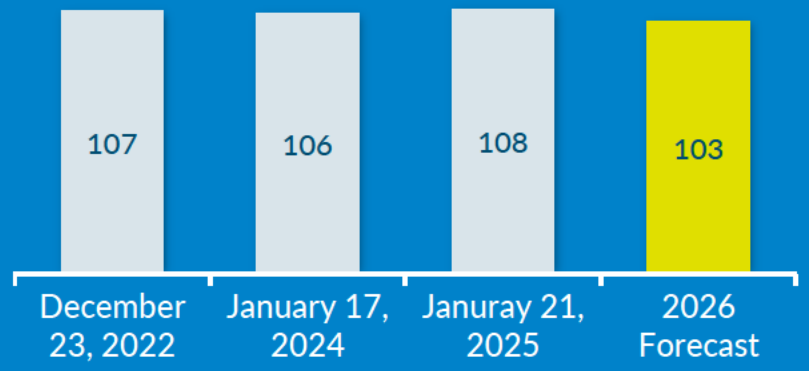
Seasonal outlook maps source: National Oceanic and Atmospheric Administration

The MISO Seasonal Resource Adequacy Construct cleared sufficient resources to cover demand this winter

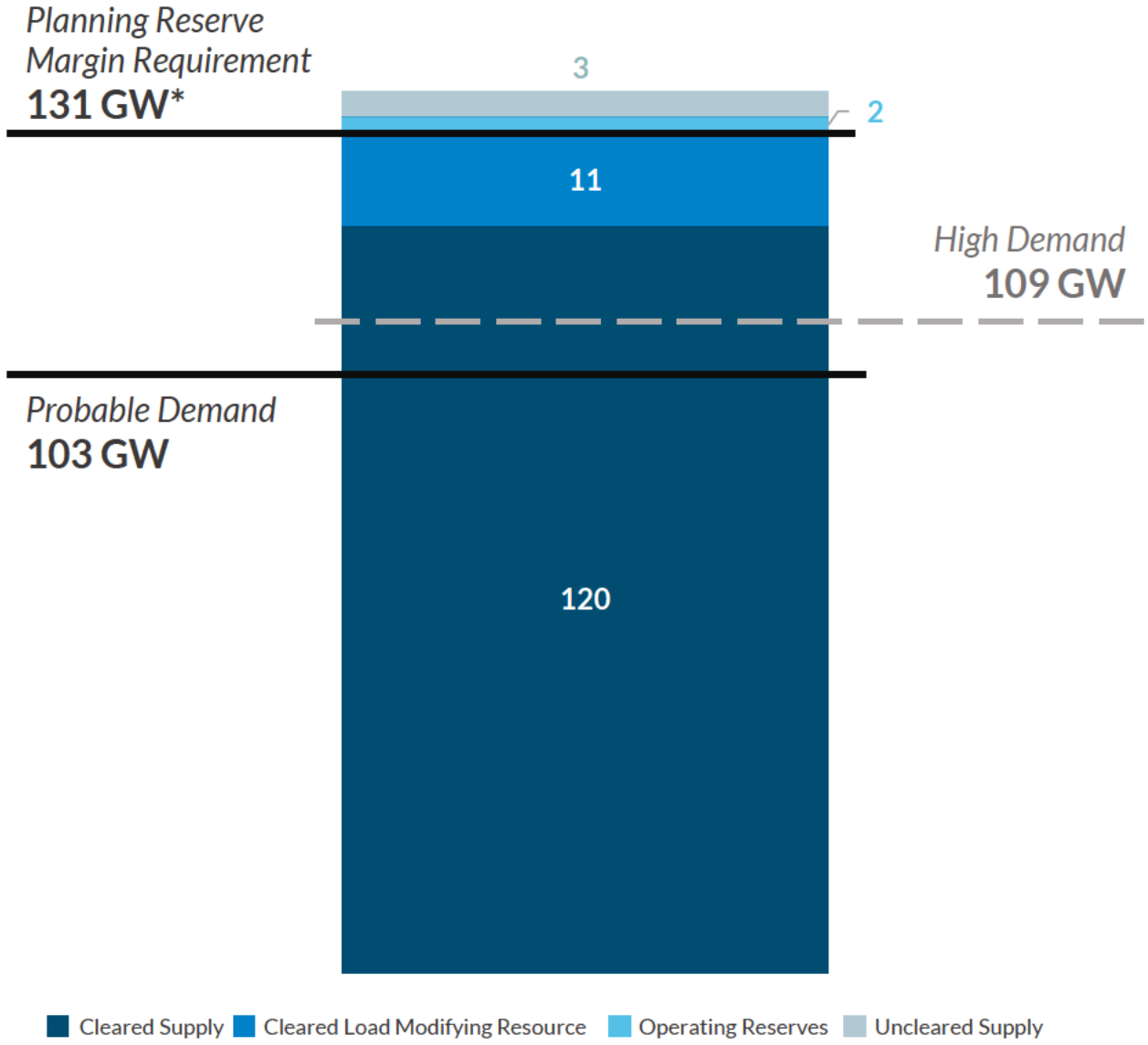
WINTER PRA CLEARING PRICES

All Zones
$33.20/MW-day

WINTER PEAK (GW)



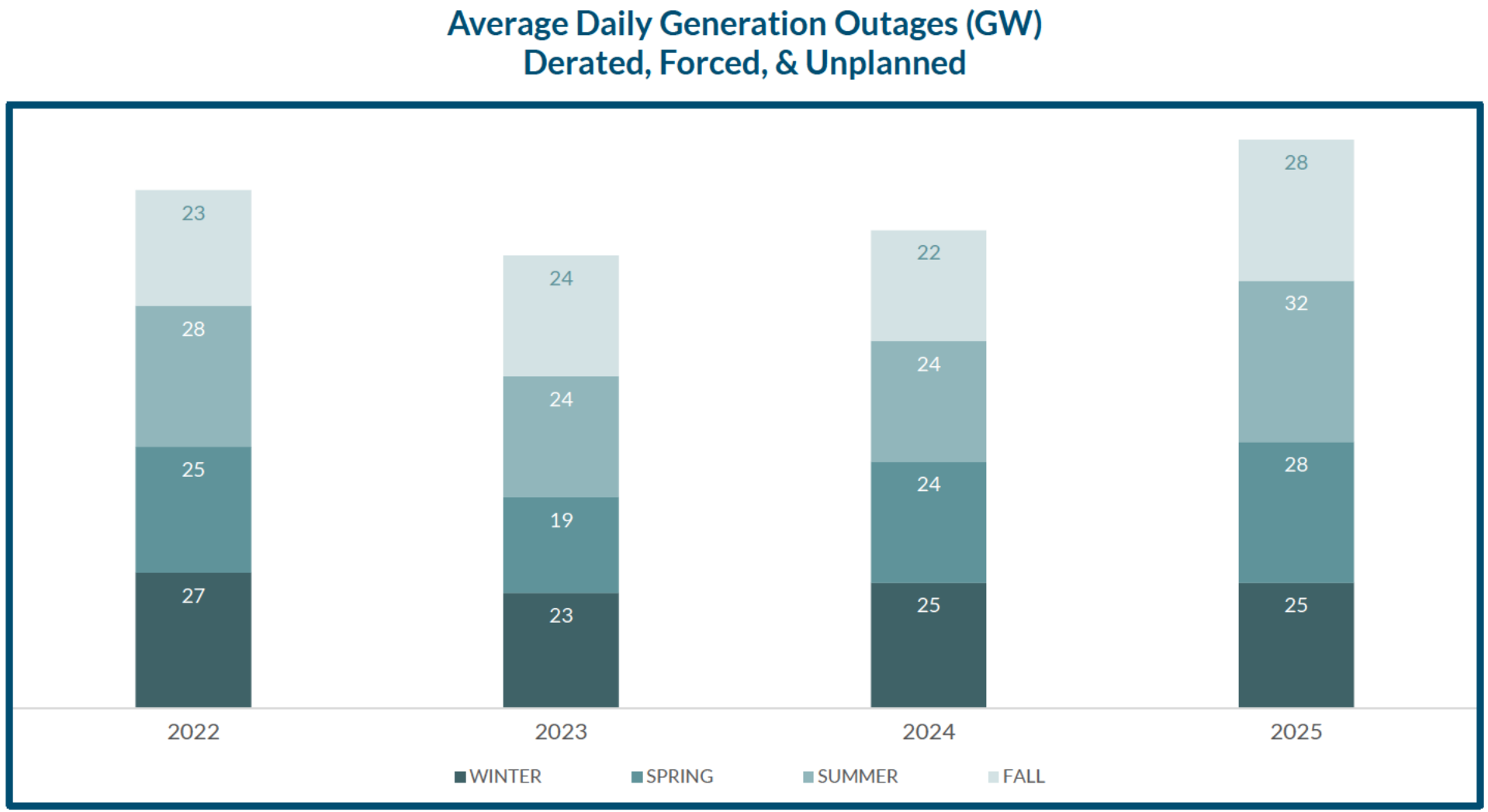
PRA – Planning Resource Auction



Appendix



Increased generation outage rates continued into the fall season



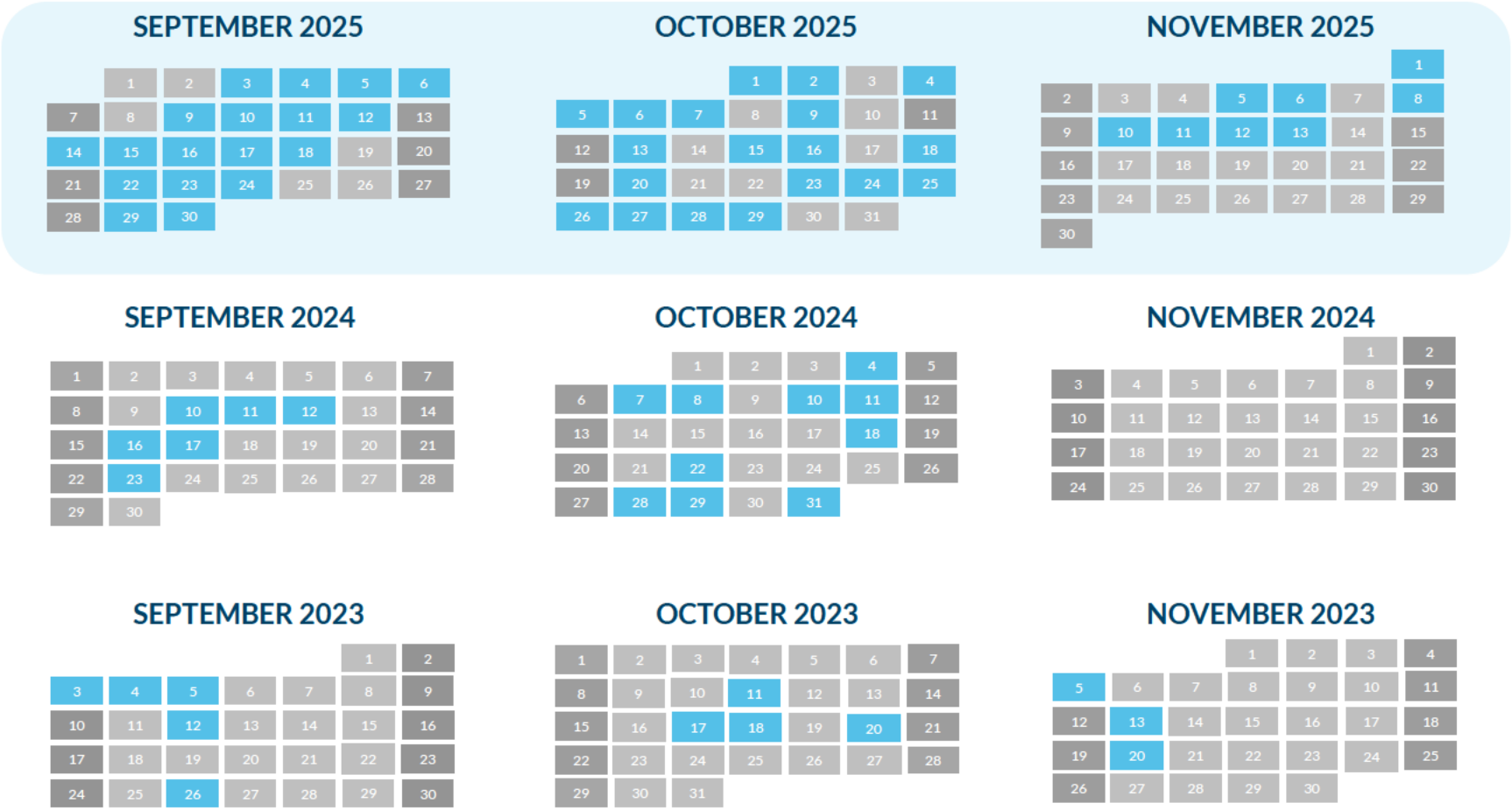
Four metrics fell outside of the expected range this fall

Metric	Status	Comments
Price Percentage Deviation	September Review	Periods of congestion and real-time ancillary service product scarcity pricing throughout the month resulted in price divergence between the Day-Ahead and Real-Time Markets.
RSG Per Megawatt Hour to Energy Price	October Monitor	84% of the total $4.4M of Real-Time RSG MWP for October was paid in the first 19 days of month to resources primarily committed by RAC to manage active transmission constraints caused by increased load demand and decreased resource capacity from the Day-Ahead clearing.

CLICK HERE to see MISO's monthly Operations Reports, which include the charts previously shared in the Appendix of this report

No reliability actions were needed this fall

FALL OPERATING CONDITIONS



Data as of 11/24/2025

Awareness and Weather *Alerts and Warnings* *Reliability Actions and Events*

Details of the Fall Operating Conditions

September

- **09/03 – Footprint:** System Status Level 1
- **09/04 – South Region:** Capacity Advisory* (Texas)
- **09/05 – South Region:** Capacity Advisory* (Texas)
- **09/06 – South Region:** Capacity Advisory* (Texas)
- **09/09 – South Region:** Capacity Advisory* (Texas)
- **09/10 – South Region:** Capacity Advisory* (Texas)
- **09/11 – South Region:** Capacity Advisory* (Texas)
- **09/12 – South Region:** Capacity Advisory* (Texas)
- **09/15 – Footprint:** Geomagnetic Disturbance Warning
- **9/15-9/17 – Footprint:** Conservative Operations
- **9/15-9/17 – Footprint:** Hot Weather Alert
- **9/15-9/18 – Footprint:** Capacity Advisory
- **09/17 – South Region:** Capacity Advisory* (Texas)
- **09/22 – Footprint:** Capacity Advisory
- **09/23 – South Region:** Capacity Advisory* (Texas and Louisiana)
- **09/24 – South Region:** Capacity Advisory* (Texas and Louisiana)
- **9/29-9/30 – Footprint:** Conservative Operations

October

- **10/01 – Footprint:** Geomagnetic Disturbance Warning
- **10/02 – Footprint:** Geomagnetic Disturbance Alert
- **10/04 – South Region:** Capacity Advisory* (Texas)
- **10/05 – South Region:** Capacity Advisory* (Texas)
- **10/06 – Central:** Conservative Operations
- **10/06 – South Region:** Capacity Advisory* (Texas)
- **10/6-10/7 – Central:** Capacity Advisory
- **10/07 – South Region:** Capacity Advisory* (Texas)
- **10/09 – Footprint:** Conservative Operations
- **10/09 – South Region:** Capacity Advisory* (Louisiana)
- **10/13 – Footprint:** System Status Level 1
- **10/15 – South Region:** Capacity Advisory* (Texas)
- **10/16 – South Region:** Capacity Advisory* (Texas)
- **10/18 – South Region:** Capacity Advisory* (Texas)
- **10/20 – AMRN:** System Status Level 1
- **10/23-10/29 – South Region:** Transmission Advisory
- **10/29 – Footprint:** System Status Level 1

November

- **11/01 – South Region:** Capacity Advisory* (Texas)
- **11/5-11/6 – Footprint:** Geomagnetic Disturbance Warning
- **11/6 – Footprint:** Geomagnetic Disturbance Alert
- **11/8 – South Region:** Capacity Advisory* (Texas)
- **11/10 – South Region:** Capacity Advisory* (Texas)
- **11/11 – South Region:** Capacity Advisory* (Texas)
- **11/11 – Footprint:** Geomagnetic Disturbance Warning
- **11/11-11/12 – Footprint:** Geomagnetic Disturbance Alert
- **11/12-11/13 – Footprint:** Geomagnetic Disturbance Warning

**MISO issued Capacity Advisories for South region load pockets to provide proactive notice of elevated reliability risk.*
Data as of 11/24/2025

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-29
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-30

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 139
Report of the National Energy Policy Development Group

National Energy Policy



Report of the National Energy Policy Development Group

May 2001

Reliable, Affordable, and Environmentally Sound Energy for America's Future

Report of the

National Energy Policy Development Group

"America must have an energy policy that plans for the future, but meets the needs of today. I believe we can develop our natural resources and protect our environment."

— President George W. Bush

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THE VICE PRESIDENT

WASHINGTON

May 16, 2001

The Honorable George W. Bush
President of the United States
The White House
Washington, D.C. 20500

Dear Mr. President:

On behalf of the National Energy Policy Development Group, I submit for your consideration our National Energy Policy report. As you directed us at the outset of your Administration, we have developed a national energy policy designed to help bring together business, government, local communities and citizens to promote dependable, affordable and environmentally sound energy for the future.

The report reflects the requirements and philosophy you set out for our work. It envisions a comprehensive long-term strategy that uses leading edge technology to produce an integrated energy, environmental and economic policy. To achieve a 21st century quality of life -- enhanced by reliable energy and a clean environment -- we must modernize conservation, modernize our infrastructure, increase our energy supplies, including renewables, accelerate the protection and improvement of our environment, and increase our energy security.

We submit these recommendations with optimism. The tasks ahead are great but achievable. To meet our energy challenge, we must put to good use the resources around us and the talents within us. It summons the best of America and offers a healthier environment, a stronger economy and a brighter future for the American people.

Sincerely,

Dick Cheney

Enclosure

PRINTED ON RECYCLED PAPER

Members of the
National Energy Policy Development Group

DICK CHENEY
The Vice President

COLIN L. POWELL
The Secretary of State

PAUL O'NEILL
The Secretary of the Treasury

GALE NORTON
The Secretary of the Interior

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The Secretary of Commerce

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LAWRENCE B. LINDSEY
The Assistant to the President for Economic Policy

RUBEN BARRALES
Deputy Assistant to the President and Director of Intergovernmental Affairs

Executive Director: Andrew D. Lundquist

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8 Strengthening Global Alliances
Enhancing National Energy Security and International Relationships

Appendix One
Summary of Report Recommendations

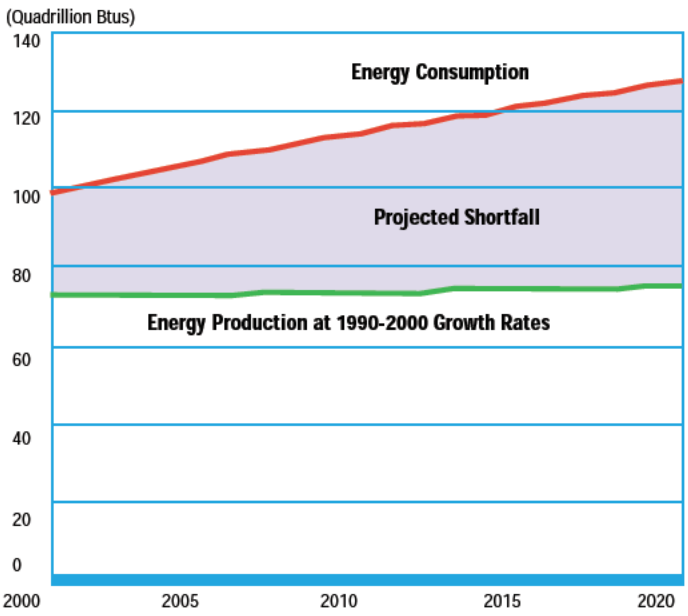
Appendix Two
Glossary

Overview

Reliable, Affordable, and Environmentally Sound Energy for America's Future

In his second week in office, President George W. Bush established the National Energy Policy Development Group, directing it to "develop a national energy policy designed to help the private sector, and, as necessary and appropriate, State and local governments, promote dependable, affordable, and environmentally sound production and distribution of energy for the future." This Overview sets forth the National Energy Policy Development (NEPD) Group's findings and key recommendations for a National Energy Policy.

Figure 1
Growth in U.S. Energy Consumption Is Outpacing Production



Over the next 20 years, growth in U.S. energy consumption will increasingly outpace U.S. energy production, if production only grows at the rate of the last 10 years.

Sources: Sandia National Laboratories and U.S. Department of Energy, Energy Information Administration.

America in the year 2001 faces the most serious energy shortage since the oil embargoes of the 1970s. The effects are already being felt nationwide. Many families face energy bills two to three times higher than they were a year ago. Millions of Americans find themselves dealing with rolling blackouts or brownouts; some employers must lay off workers or curtail production to absorb the rising cost of energy. Drivers across America are paying higher and higher gasoline prices.

Californians have felt these problems most acutely. California actually began the 1990s with a surplus of electricity generating capacity. Yet despite an economic boom, a rapidly growing population, and a corresponding increase in energy needs, California did not add a single new major electric power plant during the 1990s. The result is a demand for electricity that greatly succeeds the amount available.

A fundamental imbalance between supply and demand defines our nation's energy crisis. As the chart illustrates, if energy production increases at the same rate as during the last decade our projected energy needs will far outstrip expected levels of production.

This imbalance, if allowed to continue, will inevitably undermine our economy, our standard of living, and our national security. But it is not beyond our power to correct. America leads the world in scientific achievement, technical skill, and entrepreneurial drive. Within our country are abundant natural resources, unrivaled technology, and unlimited human creativity. With forward-looking leadership and sensible policies, we can meet our fu-



America's expanding economy, growing population, and rising standard of living will be sustained by our unmatched technological know-how.

ture energy demands and promote energy conservation, and do so in environmentally responsible ways that set a standard for the world.

The Challenge

America's energy challenge begins with our expanding economy, growing population, and rising standard of living. Our prosperity and way of life are sustained by energy use. America has the technological know-how and environmentally sound 21st century technologies needed to meet the principal energy challenges we face: promoting energy conservation, repairing and modernizing our energy infrastructure, and increasing our energy supplies in ways that protect and improve the environment. Meeting each of these challenges is critical to expanding our economy, meeting the needs of a growing population, and raising the American standard of living.

We are already working to meet the first challenge: using energy more wisely. Dramatic technological advances in energy efficiency have enabled us to make great strides in conservation, from the operation of farms and factories to the construction of buildings and automobiles. New technology allows us to go about our lives and work with less cost, less effort, and less burden on the natural environment. While such advances cannot alone solve America's energy problems, they can and will continue to play an important role in our energy future.

The second challenge is to repair and expand our energy infrastructure. Our current, outdated network of electric generators, transmission lines, pipelines, and refineries that convert raw materials into usable fuel has been allowed to deteriorate. Oil pipelines and refining capacity are in need of repair and expansion. Not a single major oil refinery has been built in the United States in nearly a generation, causing the kind of bottlenecks that lead to sudden spikes in the price of gasoline. Natural gas distribution, likewise, is hindered by an aging and inadequate network of pipelines. To match supply and demand will require some 38,000 miles of new gas pipelines, along with 255,000 miles of distribution lines. Similarly, an antiquated and inadequate transmission grid prevents us from routing electricity over long distances and thereby avoiding regional blackouts, such as California's.

"America must have an energy policy that plans for the future, but meets the needs of today. I believe we can develop our natural resources and protect our environment."

— President
George W. Bush

Increasing energy supplies while protecting the environment is the third challenge. Even with successful conservation efforts, America will need more energy.

Renewable and alternative fuels offer hope for America's energy future. But they supply only a small fraction of present energy needs. The day they fulfill the bulk of our needs is still years away. Until that day comes, we must continue meeting the nation's energy requirements by the means available to us.

Estimates indicate that over the next 20 years, U.S. oil consumption will increase by 33 percent, natural gas consumption by well over 50 percent, and demand for electricity will rise by 45 percent. If America's energy production grows at the same rate as it did in the 1990s we will face an ever-increasing gap.

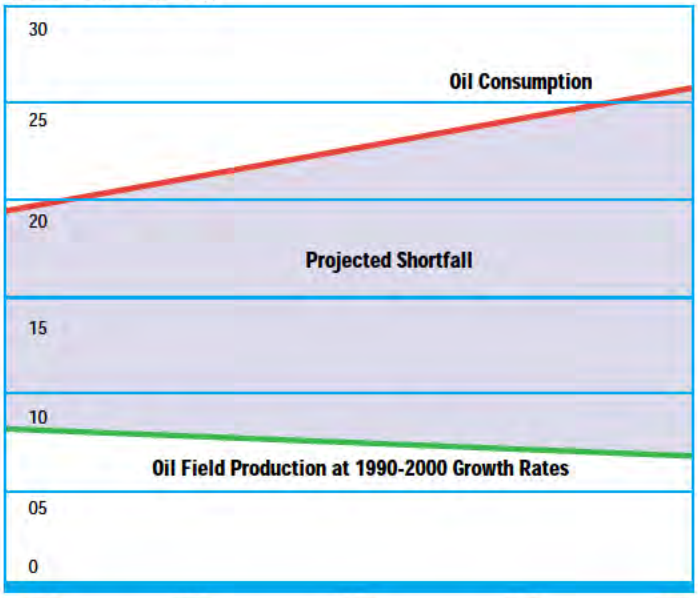
Increases on this scale will require preparation and action today. Yet America has not been bringing on line the necessary supplies and infrastructure.

Extraordinary advances in technology have transformed energy exploration and production. Yet we produce 39 percent less oil today than we did in 1970, leaving us ever more reliant on foreign suppliers. On our present course, America 20 years from now will import nearly two of every three barrels of oil – a condition of increased dependency on foreign powers that do not always have America's interests at heart. Our increasing demand for natural gas – one of the cleanest forms of energy – far exceeds the current rate of production. We should reconsider any regulatory restrictions that do not take technological advances into account.

Figure 2

U.S. Oil Consumption Will Continue to Exceed Production

(Millions of Barrels per Day)



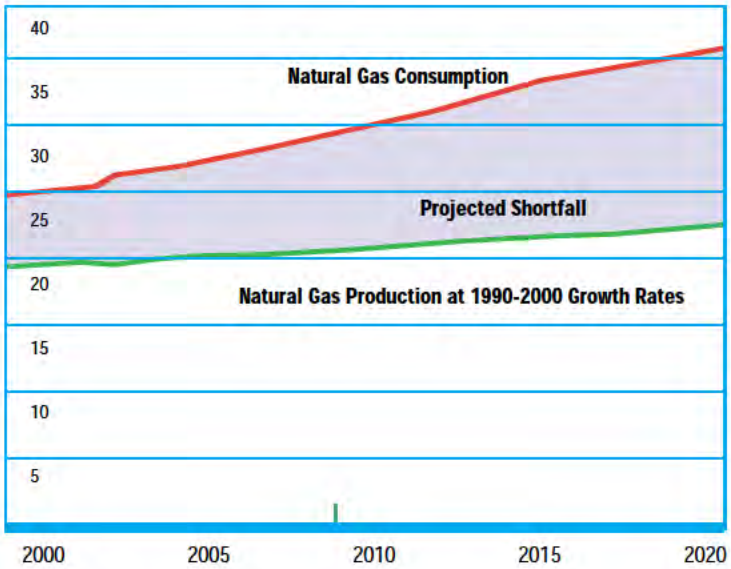
Over the next 20 years, U.S. oil consumption will grow by over 6 million barrels per day. If U.S. oil production follows the same historical pattern of the last 10 years, it will decline by 1.5 million barrels per day. To meet U.S. oil demand, oil and product imports would have to grow by a combined 7.5 million barrels per day. In 2020, U.S. oil production would supply less than 30 percent of U.S. oil needs.

Sources: Sandia National Laboratories and U.S. Department of Energy, Energy Information Administration.

Figure 3

U.S. Natural Gas Consumption Is Outpacing Production

(Trillion Cubic Feet)



Over the next 20 years, U.S. natural gas consumption will grow by over 50 percent. At the same time, U.S. natural gas production will grow by only 14 percent, if it grows at the rate of the last 10 years.

Sources: Sandia National Laboratories and U.S. Department of Energy, Energy Information Administration.

erview chart

We have a similar opportunity to increase our supplies of electricity. To meet projected demand over the next two decades, America must have in place between 1,300 and 1,900 new electric plants. Much of this new generation will be fueled by natural gas. However, existing and new technologies offer us the opportunity to expand nuclear generation as well. Nuclear power today accounts for 20 percent of our country's electricity. This power source, which causes no greenhouse gas emissions, can play an expanding part in our energy future.

The recommendations of this report address the energy challenges facing America. Taken together, they offer the thorough and responsible energy plan our nation has long needed.

Components of the National Energy Policy

The National Energy Policy we propose follows three basic principles:

- The Policy is a long-term, comprehensive strategy. Our energy crisis has been years in the making, and will take years to put fully behind us.
- The Policy will advance new, environmentally friendly technologies to increase energy supplies and encourage cleaner, more efficient energy use.
- The Policy seeks to raise the living standards of the American people, recognizing that to do so our country must fully integrate its energy, environmental, and economic policies.

Applying these principles, we urge action to meet five specific national goals. America must modernize conservation, modernize our energy infrastructure, increase energy supplies, accelerate the protection and improvement of the environment, and increase our nation's energy security.

Modernize Conservation

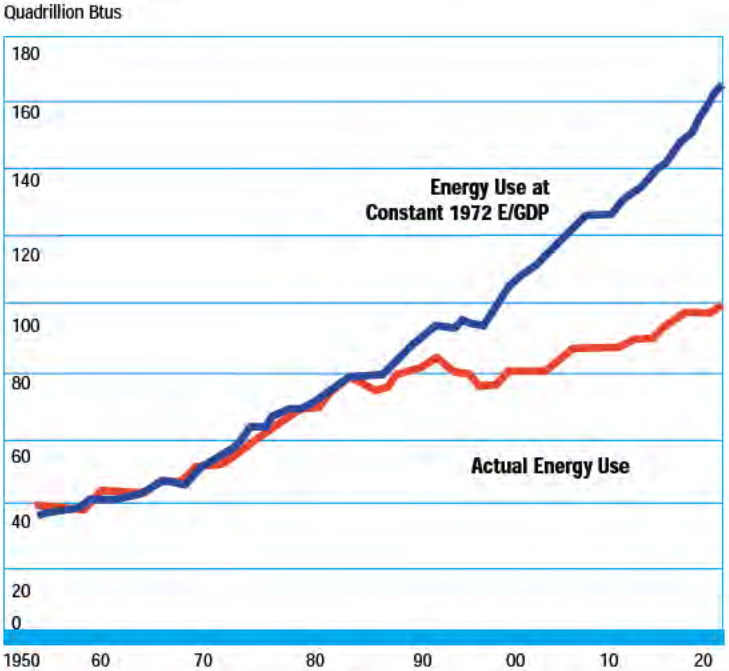
Americans share the goal of energy conservation. The best way of meeting this goal is to increase energy efficiency by applying new technology – raising productivity, reducing waste, and trimming costs. In addition, it holds out great hope for improving the quality of the environment. American families, communities, and businesses all depend upon reliable and affordable energy services for their well being and safety. From transportation to communication, from air conditioning to lighting, energy is critical to nearly everything we do in life and work. Public policy can and should encourage energy conservation.

Over the past three decades, America has made impressive gains in energy efficiency. Today's automobiles, for example, use about 60 percent of the gasoline they

"Here we aim to continue a path of uninterrupted progress in many fields... New technologies are proving that we can save energy without sacrificing our standard of living. And we're going to encourage it in every way possible."

— Vice President
Richard B. Cheney

Figure 4
U.S. Economy is More Energy Efficient (Energy Intensity)
Primary Energy Use



Improvements in energy efficiency since the 1970s have had a major impact in meeting national energy needs relative to new supply. If the intensity of U.S. energy use had remained constant since 1972, consumption would have been about 70 quadrillion Btus (74 percent) higher in 1999 than it actually was.

Source: U.S. Department of Energy, Energy Information Administration.

did in 1972, while new refrigerators require just one-third the electricity they did 30 years ago. As a result, since 1973, the U.S. economy has grown by 126 percent, while energy use has increased by only 30 percent. In the 1990s alone, manufacturing output expanded by 41 percent, while industrial electricity consumption grew by only 11 percent. We must build on this progress and strengthen America's commitment to energy efficiency and conservation.

The National Energy Policy builds on our nation's successful track record and will promote further improvements in the productive and efficient use of energy. This report includes recommendations to:

- Direct federal agencies to take appropriate actions to responsibly conserve energy use at their facilities, especially during periods of peak demand in regions where electricity shortages are possible, and to report to the President on actions taken.
- Increase funding for renewable energy and energy efficiency research and development programs that are performance-based and cost-shared.
- Create an income tax credit for the purchase of hybrid and fuel cell vehicles to promote fuel-efficient vehicles.
- Extend the Department of Energy's "Energy Star" efficiency program to include schools, retail buildings, health care facilities, and homes and extend the "Energy Star" labeling program to additional products and appliances.
- Fund the federal government's Intelligent Transportation Systems program, the fuel cell powered transit bus program, and the Clean Buses program.
- Provide a tax incentive and streamline permitting to accelerate the development of clean Combined Heat and Power technology.
- Direct the Secretary of Transportation to review and provide recommendations on establishing Corporate Average Fuel Economy (CAFE) standards with due consideration to the National Academy of Sciences study of CAFE standards to be released in July, 2001.

Modernize Our Energy Infrastructure

The energy we use passes through a vast nationwide network of generating facilities, transmission lines, pipelines, and refineries that converts raw resources into usable fuel and power. That system is deteriorating, and is now strained to capacity.

One reason for this is government regulation, often excessive and redundant. Regulation is needed in such a complex field, but it has become overly burdensome. Regulatory hurdles, delays in issuing permits, and economic uncertainty are limiting investment in new facilities, making our energy markets more vulnerable to transmission bottlenecks, price spikes and supply disruptions. America needs more environmentally-sound energy projects to connect supply sources to growing markets and to deliver energy to homes and business.

To reduce the incidence of electricity blackouts, we must greatly enhance our ability to transmit electric power between geographic regions, that is, sending power to where it is needed from where it is produced. Most of America's transmission lines, substations, and transformers were built when utilities were tightly regulated and provided service only within their assigned regions. The system is simply unequipped for large-scale swapping of power in the highly competitive market of the 21st century.

The National Energy Policy will modernize and expand our energy infrastructure in order to ensure that energy supplies can be safely, reliably, and affordably transported to homes and businesses. This report includes recommendations to:

- Direct agencies to improve pipeline safety and expedite pipeline permitting.
- Issue an Executive Order directing federal agencies to expedite permits and coordinate federal, state, and local actions necessary for energy-related project approvals on a national basis

"For the electricity we need, we must be ambitious. Transmission grids stand in need of repair, upgrading, and expansion. . . . If we put these connections in place, we'll go a long way toward avoiding future blackouts."

— Vice President
Richard B. Cheney

in an environmentally sound manner, and establish an interagency task force chaired by the Council on Environmental Quality. The task force will ensure that federal agencies set up appropriate mechanisms to coordinate federal, state and local permitting activity in particular regions where increased activity is expected.

- Grant authority to obtain rights-of-way for electricity transmission lines with the goal of creating a reliable national transmission grid. Similar authority already exists for natural gas pipelines and highways.
- Enact comprehensive electricity legislation that promotes competition, encourages new generation, protects consumers, enhances reliability, and promotes renewable energy.
- Implement administrative and regulatory changes to improve the reliability of the interstate transmission system and enact legislation to provide for enforcement of electricity reliability standards.
- Expand the Energy Department's research and development on transmission reliability and superconductivity.

Increase Energy Supplies

A primary goal of the National Energy Policy is to add supply from diverse sources. This means domestic oil, gas, and coal. It also means hydropower and nuclear power. And it means making greater use of non-hydro renewable sources now available.

One aspect of the present crisis is an increased dependence, not only on foreign oil, but on a narrow range of energy options. For example, about 90 percent of all new electricity plants currently under construction will be fueled by natural gas. While natural gas has many advantages, an over-reliance on any one fuel source leaves consumers vulnerable to price spikes and supply disruptions. There are several other fuel sources available that can help meet our needs.

Currently, the U.S. has enough coal to last for another 250 years. Yet very few coal-powered electric plants are now under construction. Research into clean coal technologies may increase the attractiveness of coal as a source for new generation plants.

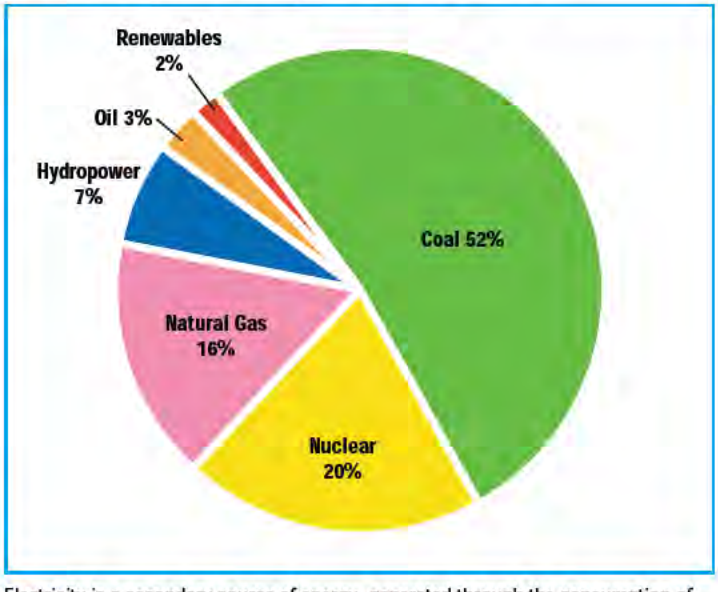
Nuclear power plants serve millions of American homes and businesses, have a dependable record for safety and efficiency, and discharge no greenhouse gases into the atmosphere. As noted earlier, these facilities currently generate 20 percent of all electricity in America, and more than 40 percent of electricity generated in 10 states in the Northeast, South, and Midwest. Other nations, such as Japan and France, generate a much higher percentage of their electricity from nuclear power. Yet the number of nuclear plants in America is actually projected to decline in coming years, as old plants close and none are built to replace them.

Enormous advances in technology have made oil and natural gas exploration and production both more efficient and more environmentally sound. Better technology means fewer rigs, more accurate drilling, greater resource recovery and envi-

"As a country, we have demanded more and more energy. But we have not brought on line the supplies needed to meet that demand.... We can explore for energy, we can produce energy and use it, and we can do so with a decent regard for the natural environment."

—Vice President
Richard B. Cheney

Figure 5
Fuel Sources for Electricity Generation in 2000



Electricity is a secondary source of energy, generated through the consumption of primary sources. Coal and nuclear energy account for nearly 75 percent of U.S. electricity generation.

Source: U.S. Department of Energy, Energy Information Administration

ronmentally friendly exploration. Drilling pads are 80 percent smaller than a generation ago. High-tech drilling allows us to access supplies five to six miles away from a single compact drilling site, leaving sensitive wetlands and wildlife habitats undisturbed. Yet the current regulatory structure fails to take sufficient account of these extraordinary advances, excessively restricting the environmentally safe production of energy from many known sources.

Our policy will increase and diversify our nation's sources of traditional and alternative fuels in order to furnish families and businesses with reliable and affordable energy, to enhance national security, and to improve the environment. This report includes recommendations to:

- Issue an Executive Order directing all federal agencies to include in any regulatory action that could significantly and adversely affect energy supplies a detailed statement on the energy impact of the proposed action.
- Open a small fraction of the Arctic National Wildlife Refuge to environmentally regulated exploration and production using leading-edge technology. Examine the potential for the regulated increase in oil and natural gas development on other federal lands.
- Earmark $1.2 billion of bid bonuses from the environmentally responsible leasing of ANWR to fund research into alternative and renewable energy resources – including wind, solar, biomass, and geothermal.
- Enact legislation to expand existing alternative fuels tax incentives to include landfills that capture methane gas emissions for electricity generation and to electricity produced from wind and biomass. Extend the number of eligible biomass sources to include forest-related sources, agricultural sources, and certain urban sources.
- Provide $2 billion over 10 years to fund clean coal technology research and a new credit for electricity produced from biomass co-fired with coal.
- Direct federal agencies to streamline the hydropower relicensing process with proper regard given to environmental factors.
- Provide for the safe expansion of nuclear energy by establishing a national repository for nuclear waste, and by streamlining the licensing of nuclear power plants.

Accelerate Protection and Improvement of the Environment

America's commitment to environmental protection runs deep. We are all aware of past excesses in our use of the natural world and its resources. No one wishes to see them repeated. In the 21st century, the ethic of good stewardship is well established in American life and law.

We do not accept the false choice between environmental protection and energy production. An integrated approach to policy can yield a cleaner environment, a stronger economy, and a sufficient supply of energy for our future. The primary reason for that has been steady advances in the technology of locating, producing, and using energy. Since 1970, emissions of key air emissions are down 31 percent. Cars today emit 85 percent less carbon monoxide than 30 years ago. Lead emissions are down 90 percent. Lead levels in ambient air today are 98 percent lower than they were in 1970. America is using more, and polluting less.

One of the factors harming the environment today is the very lack of a comprehensive, long-term national energy policy. States confronting blackouts must take desperate measures, often at the expense of environmental standards, requesting waivers of environmental rules, and delaying the implementation of anti-pollution efforts. Shortfalls in electricity generating capacity and short-sighted policies have blocked construction of new, cleaner plants, leaving no choice but to rely on older, inefficient plants to meet demand. The increased use of emergency power sources, such as diesel generators, results in greater air pollution.

New anti-pollution technologies hold great promise for the environment. The same can be said of 21st century power generators that must soon replace older models; signifi-

"We will insist on protecting and enhancing the environment, showing consideration for the air and natural lands and watersheds of our country."

— Vice President
Richard B. Cheney

cant new resources for land conservation efforts; and continued research into renewable energy sources. All have a place in the National Energy Policy.

The National Energy Policy will build upon our nation's successful track record and will promote further improvements in the productive and efficient use of energy. This report includes recommendations to:

- Enact "multi-pollutant" legislation to establish a flexible, market-based program to significantly reduce and cap emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power generators.
- Increase exports of environmentally friendly, market-ready U.S. technologies that generate a clean environment and increase energy efficiency.
- Establish a new "Royalties Conservation Fund" and earmark royalties from new, clean oil and gas exploration in ANWR to fund land conservation efforts.
- Implement new guidelines to reduce truck idling emissions at truck stops.

Increase Energy Security.

The National Energy Policy seeks to lessen the impact on Americans of energy price volatility and supply uncertainty. Such uncertainty increases as we reduce America's dependence on foreign sources of energy. At the same time, however, we recognize that a significant percentage of our resources will come from overseas. Energy security must be a priority of U.S. trade and foreign policy.

We must look beyond our borders and restore America's credibility with overseas suppliers. In addition, we must build strong relationships with energy-producing nations in our own hemisphere, improving the outlook for trade, investment, and reliable supplies.

Energy security also requires preparing our nation for supply emergencies, and assisting low-income Americans who are most vulnerable in times of supply disruption, price spikes, and extreme weather.

To ensure energy security for our nation and its families, our report includes these recommendations:

- Dedicate new funds to the Low Income Home Energy Assistance Program by funneling a portion of oil and gas royalty payments to LIHEAP when oil and natural gas prices exceed a certain amount.
- Double funding for the Department of Energy's Weatherization Assistance Program, increasing funding by $1.4 billion over 10 years.
- Direct the Federal Emergency Management Administration to prepare for potential energy-related emergencies.
- Support a North American Energy Framework to expand and accelerate cross-border energy investment, oil and gas pipelines, and electricity grid connections by streamlining and expediting permitting procedures with Mexico and Canada. Direct federal agencies to expedite necessary permits for a gas pipeline route from Alaska to the lower 48 states.

Looking Toward the Future

The President's goal of reliable, affordable, and environmentally sound energy supplies will not be reached overnight. It will call forth innovations in science, research, and engineering. It will require time and the best efforts of leaders in both political parties. It will require also that we deal with the facts as they are, meeting serious problems in a serious way. The complacency of the past decade must now give way to swift but well-considered action.

Present trends are not encouraging, but they are not immutable. They are among today's most urgent challenges, and well within our power to overcome. Our country has met many great tests. Some have imposed extreme hardship and sacrifice. Others have demanded only resolve, ingenuity, and clarity of purpose. Such is the case with energy today.

We submit these recommendations with optimism. We believe that the tasks ahead, while great, are achievable. The energy crisis is a call to put to good use the resources around us, and the talents within us. It summons the best of America, and offers the best of rewards – in new jobs, a healthier environment, a stronger economy, and a brighter future for our people.

"The goals of this strategy are clear: to ensure a steady supply of affordable energy for America's homes and businesses and industries."

— President
George W. Bush

Taking Stock

Energy Challenges Facing the United States

America's current energy challenges can be met with rapidly improving technology, dedicated leadership, and a comprehensive approach to our energy needs. Our challenge is clear—we must use technology to reduce demand for energy, repair and maintain our energy infrastructure, and increase energy supply. Today, the United States remains the world's undisputed technological leader; but recent events have demonstrated that we have yet to integrate 21st-century technology into an energy plan that is focused on wise energy use, production, efficiency, and conservation.

Prices today for gasoline, heating oil, and natural gas are dramatically higher than they were only a year ago. In California, homeowners, farmers, and businesses face soaring electricity prices, rolling blackouts, increasing financial turmoil, and an uncertain energy future. Our nation's dependence on foreign sources of oil is at an all-time high and is expected to grow. Current high energy prices and supply shortages are hurting U.S. consumers and businesses, as well as their prospects for continued economic growth.

Our national energy policy must be comprehensive in scope. It must protect our environment. It must also increase our supply of domestic oil, natural gas, coal, nuclear, and renewable energy sources. Our failure over the past several years to modernize our energy infrastructure—the network of transmission lines, gas pipelines, and oil refineries that transports our energy to consumers and converts raw materials into usable fuels—is a result of the lack of careful planning and lack of a comprehensive national energy plan. The United States faces serious energy challenges: electricity shortages and disruptions in California and elsewhere in the West, dramatic increases in gasoline prices due to record-low inventories, a strained supply system, and continued dependence on foreign suppliers. These challenges have developed from years of neglect and can only be addressed with the implementation of sound policy. There are no easy, short-term solutions.

Our increased dependence on foreign oil profoundly illustrates our nation's failure to establish an effective energy policy. Between 1991 and 2000, Americans used 17 percent more energy than in the previous decade, while during that same period, domestic energy production rose by only 2.3 percent. While U.S. production of coal, natural gas, nuclear energy, and renewable energy has increased somewhat in recent years, these increases have been largely offset by declines in domestic oil production. As a result, America has met almost all of its increased energy demand over the past ten years with increased imports.

U.S. energy consumption is projected to increase by about 32 percent by 2020. Unless a comprehensive national energy policy is adopted, Americans will continue to feel the effects of an inadequate electrical transmission grid, a pipeline system stretched to capacity, insufficient domestic energy supply, and a regional imbalance in supply sources. It is important that we meet these challenges with a comprehensive energy plan that takes a long-term approach to meeting our energy needs.



The U.S. economy depends on reliable and affordable energy. In the coming months, we face several serious long-term energy challenges: electricity shortages and disruptions in California and the West, dramatic increases in gasoline prices due to record-low inventories, a strained supply system, and continued dependence on foreign suppliers.

Philadelphia Convention & Visitors Bureau



California's Energy Challenge

Recent and looming electricity blackouts in California demonstrate the problem of neglecting energy supply. They also foretell the consequences of failing to implement a long-term energy plan for our nation as a whole. Though weather conditions and design flaws in California's electricity restructuring plan contributed, the California electricity crisis is at heart a supply crisis.

Since 1995, California's peak summer demand for electricity has risen by at least 5,500 megawatts (MW), while in-state generation has failed to keep pace. California's generation shortfall did not stem from a lack of interest in building capacity. Since 1997, power producers filed applications to build an additional 14,000 MW of new capacity in California.

In addition to a lack of new generation, a crucial transmission bottleneck in the middle of the state—called Path 15—prevents power in the south from being shipped to the north during emergencies.

This year, reduced hydropower availability due to low rainfall, higher than expected unplanned plant outages, and the financial problems of California's utilities exacerbated this growing supply–demand imbalance. As a result, California's supply problem turned into a crisis, resulting in soaring electricity bills for homes and businesses and rolling blackouts.

In part due to the interconnected nature of the western electricity grid, California's critical electricity shortages have helped to drive up electricity costs in the West.

Unfortunately, there are no short-term solutions to long-term neglect. It can take new power plants and transmission facilities years to site, permit, and construct. Despite expedited federal permitting, California's emergency efforts to increase new generation by 5,000 MW by July appear to be falling short. Less than 2,000 MW of new generation is expected to be in place by summer. Even with aggressive conservation measures, peak demand this summer is projected to outstrip supply by several thousand megawatts. The California grid operator expects more than 30 days of blackouts.

California officials have warned that the crisis may last several years. Though California's efforts to increase generation may not suffice to prevent blackouts this summer, if continued and strengthened, they promise to limit the duration of the crisis.

Recommendations:

★ The National Energy Policy Development (NEPD) Group recommends that the President issue an Executive Order to direct all federal agencies to include in any regulatory action that could significantly and adversely affect energy supplies, distribution, or use, a detailed statement on (1) the energy impact of the proposed action, (2) any adverse energy effects that cannot be avoided should the proposal be implemented, and (3) alternatives to the proposed action. The agencies would be directed to include this statement in all submissions to the Office of Management and Budget of proposed regulations covered by Executive Order 12866, as well as in all notices of proposed regulations published in the Federal Register.

★ The NEPD Group recommends that the President direct the executive agencies to work closely with Congress to implement the legislative components of a national energy policy.

Conservation and Energy Efficiency

Conservation and energy efficiency are crucial components of a national energy plan. Energy efficiency is the ability to use less energy to produce the same amount of useful work or services. Conservation is closely related and is simply using less energy. Improved energy efficiency and conservation reduces energy consumption and energy costs, while maintaining equivalent service in our homes, offices, factories, and automobiles. Greater energy

efficiency helps the United States reduce energy imports, the likelihood of energy shortages, emissions, and the volatility of energy prices.

Over the last three decades, the United States has significantly improved its energy efficiency by developing and expanding the use of energy efficient technologies. Although our economy has grown by 126 percent since 1973, our energy use has increased by only 30 percent. Had energy use kept pace with economic growth, the nation would have consumed 171 quadrillion British thermal units (Btus) last year instead of 99 quadrillion Btus.

About a third to a half of these savings resulted from shifts in the economy, such as the growth of the service sector. The other half to two-thirds resulted from greater energy efficiency. Technological improvements in energy efficiency allow consumers to enjoy more energy services without commensurate increases in energy demand. The rate at which these efficiency improvements are made varies over time, depending on the extent to which factors—such as energy policies, research and development, prices, and market regulations—encourage the development of new, efficient products and consumer investment in these products. An increased rate of improvement in energy efficiency can have a large impact on energy supply and infrastructure needs, reducing the need for new power plants and other energy resources, along with reduced stress on the energy supply infrastructure.

Load management is the ability to adjust energy loads to reflect immediate supply conditions. In the very short term, direct appeals for conservation can ease strained energy supply markets for a time. Over the longer run, the ability to adjust demand on an as-needed basis can be an important source of energy reserves, resulting in lower energy bills for participating customers.

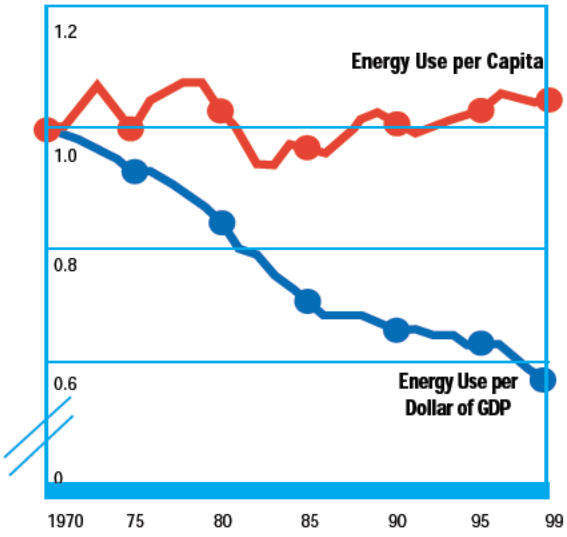
The impact that improvements in energy efficiency can have on energy supply markets grows over time. Electricity demand is projected to rise by 1.8 percent a year over the next 20 years, requiring the addition of some 393,000 MW of generation capacity. At the same time, energy efficiency is projected to continue to improve between 2000 and 2020. A decrease in demand from 1.8 percent to 1.5 percent would reduce the need for new generating capacity next year by about 2,000 MW. Extending that reduction over the next 20 years would reduce the need for new generation by 60,000 to 66,000 MW.

While this projection shows that conservation can help ensure the United States has adequate energy supplies for the future, it also shows that conservation alone is not the answer. Even with more conservation, the U.S. will need more energy supplies. Today, new technologies offer new opportunities to enhance our energy efficiency. As these technologies gain market acceptance, they will help ensure a reliable and affordable energy and electric power supply for the nation.

Energy Intensity

The energy intensity of the U.S. economy is measured by the amount of energy used to produce a dollar's worth of gross domestic product (GDP). It now takes only about 56 percent of the energy required in 1970 to produce a

Figure 1-1
U.S. Energy Use per Capita and per Dollar of GDP: 1970–1999
(Index: 1970 = 1)



The energy intensity of the U.S. economy is measured by the amount of energy used to produce a dollar's worth of gross domestic product (GDP). By that yardstick, U.S. energy intensity declined significantly between 1970 and 1985, and has continued to decline, albeit at a slower rate.

Source: U.S. Department of Energy, Energy Information Administration.

Measures of Electrical Power

A watt is a measure of the amount of energy that can be produced during a specific period of time.

1 kilowatt (KW)= 1,000 watts
1 megawatt (MW)=1million watts
1 gigawatt (GW)=1 billion watts
1 terawatt (TW)=1 trillion watts

U.S. Energy Efficiency Is Improving

- New home refrigerators now use about one-third less energy than they did in 1972.
- New commercial fluorescent lighting systems use less than half the energy they did during the 1980s.
- Federal buildings now use about 20 percent less energy per square foot since 1985.
- Industrial energy use per unit of output declined by 25 percent from 1980 to 1999.
- The chemical industry's energy use per unit of output has declined by roughly 40 percent in the past 25 years.
- The U.S. government has reduced its energy use in buildings by over 20 percent since 1985.
- The amount of energy required to generate 1 kilowatt-hour of electricity has declined by 10 percent since 1980.

What Causes Transmission Constraints?

When additional electricity flow from one area exceeds a circuit's capacity to carry that flow to another area, the overloaded circuit becomes congested and blocks a steady flow of power. To prevent transmission bottlenecks, system operators curtail transactions between areas or increase generation on the side of the constraint where the electricity is flowing and reduce generation on the opposite side. Transmission constraints result in price differences between regions that exceed differences due to line losses, because electricity can no longer flow freely to the affected area.

dollar of GDP today (Figure 1-1). This reduction is attributable to improved energy efficiency, as well as to structural changes in the economy, particularly the relative decline of energy-intensive industries.

The decline in the nation's energy intensity accelerated between 1999 and 2000, a period when nonenergy-intensive industries experienced rapid growth. Energy intensity is projected to continue to decline through 2020 at an average rate of 1.6 percent a year. This is a slower rate of decline than experienced in the 1970s and early 1980s, which was characterized by high energy prices and a shift to less energy-intensive industries, but is a more rapid rate of decline than experienced on average during the latter part of the 1980s and the 1990s.

Challenges Confronting Electricity Supply

Our nation's electricity supply has failed to keep pace with growing demand. This imbalance is projected to persist into the future. The adverse consequences have manifested themselves most severely in the West, where supply shortages have led to high prices and even blackouts. In other regions, inadequate supply threatens the reliability and affordability of electric power.

Large amounts of new generating capacity are slated for installation around the country from 2001 to 2004. However, there is a geographic mismatch between where we will generate energy and where it is needed. For example, little capacity is being added where it is most needed, such as in California and eastern New York.



A pressing long-term electricity challenge is to build enough new generation and transmission capacity to meet projected growth in demand.

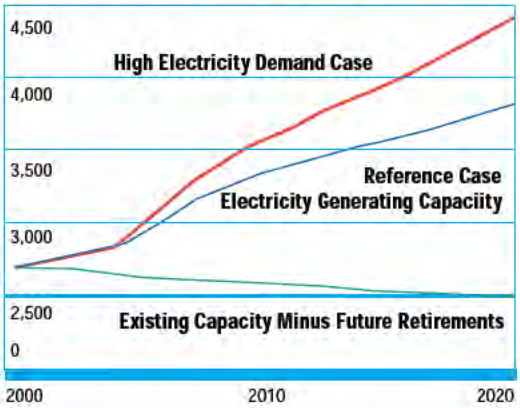
Electricity supply conditions in the Southeast are expected to be tight in the summer of 2001, much as they have been the previous two years. The Northeast may also face supply shortages. If the temperatures of the summer of 2000 had been normal rather than unseasonably cool, New York and New England would most likely have experienced electricity supply shortfalls and price spikes. Critical supply problems could arise if the weather in the summer of 2001 is unusually warm or if plant outages rise above average levels.

Our nation's most pressing long-term electricity challenge is to build enough new generation and transmission capacity to meet projected growth in demand. Across the country, we are seeing the same signs that California faced in the mid-1990s: significant economic regulatory uncertainty, which can result in inadequate supply. This level of uncertainty can vary across the country, depending on state and local regulations. Of the approximately 43,000 MW of new generating capacity that power companies planned in 1994 for construction from 1995 to 1999, only about 18,000 MW were actually built. Although plans have been announced to build more capacity than the country will need over the next five to seven years, this new construction assumes market and regulatory conditions that are not yet assured. Over the next twenty years, the United States will need 1,300 to 1,900 new power plants, which is the equivalent of 60 to 90 new power plants a year (Figure 1-2).

But even with adequate generating capacity, we do not have the infrastructure to ensure reliable supply of electricity. Investment in new transmission capacity has failed to keep pace with growth in demand and with changes in the industry's structure. Since 1989, electricity sales to consumers have increased by 2.1 percent annually, yet transmission capacity has increased by only 0.8 percent annually. As electricity markets become more regional, transmission constraints are impeding the movement of electricity both within and between regions.

The price spikes in the Midwest in the summer of 1998 were in part caused by trans-

Figure 1-2
The U.S. Needs More Power Plants



The nation is going to require significant new generation capacity in the next two decades. Depending on demand, the United States will need to build between 1,300 and 1,900 new power plants—or about one new power plant a week.

Source: U.S. Department of Energy, Energy Information Administration.

mission constraints, which limited the region's ability to import electricity from other regions at a time of high demand. Transmission bottlenecks contributed to the blackouts in California over the past year, and have been a persistent cause of price spikes in New York City during peak demand. Constraints on New England's ability to import low-cost power from Canada could raise electricity prices during periods of high demand.

Electricity is a secondary source of energy, generated through the consumption of primary sources (Figure 1-3). The largest source of U.S. electricity generation is coal, followed by nuclear energy, natural gas, hydropower, oil, and non-hydropower renewable energy.

Coal

Coal is America's most abundant fuel source. The United States has a 250-year supply of coal. Over 1 billion tons of coal were produced in 25 states in 2000. About 99.7 percent of U.S. coal production is consumed domestically, with electricity generation accounting for about 90 percent of coal consumption.

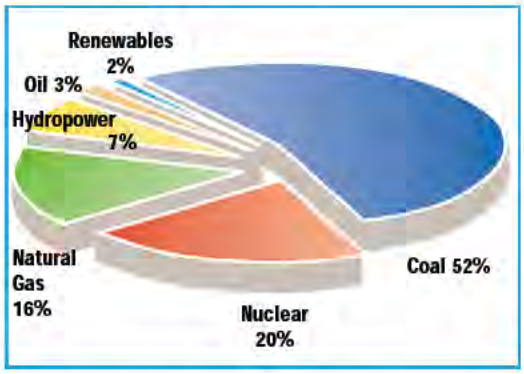
After peaking in 1982, coal prices have generally declined. This trend is projected to continue through 2020, reflecting an expanding shift into lower-cost western coal production and substantial increases in productivity. While coal is expected to remain the dominant fuel in meeting increasing U.S. electricity demand through 2020, energy policy goals must be carefully integrated with environmental policy goals. The Clean Air Act Amendments of 1990 and related state regulations require electricity generators to reduce emissions of sulfur dioxide and nitrogen oxide.

Nuclear Energy

Nuclear energy is the second-largest source (20 percent) of U.S. electricity generation. Nuclear power is used exclusively to generate electricity. Nuclear power has none of the emissions associated with coal and gas power plants, including nitrogen oxides, sulfur dioxide, mercury and carbon dioxide. Costs of electricity generation by nuclear plants compare favorably with the costs of generation by other sources.

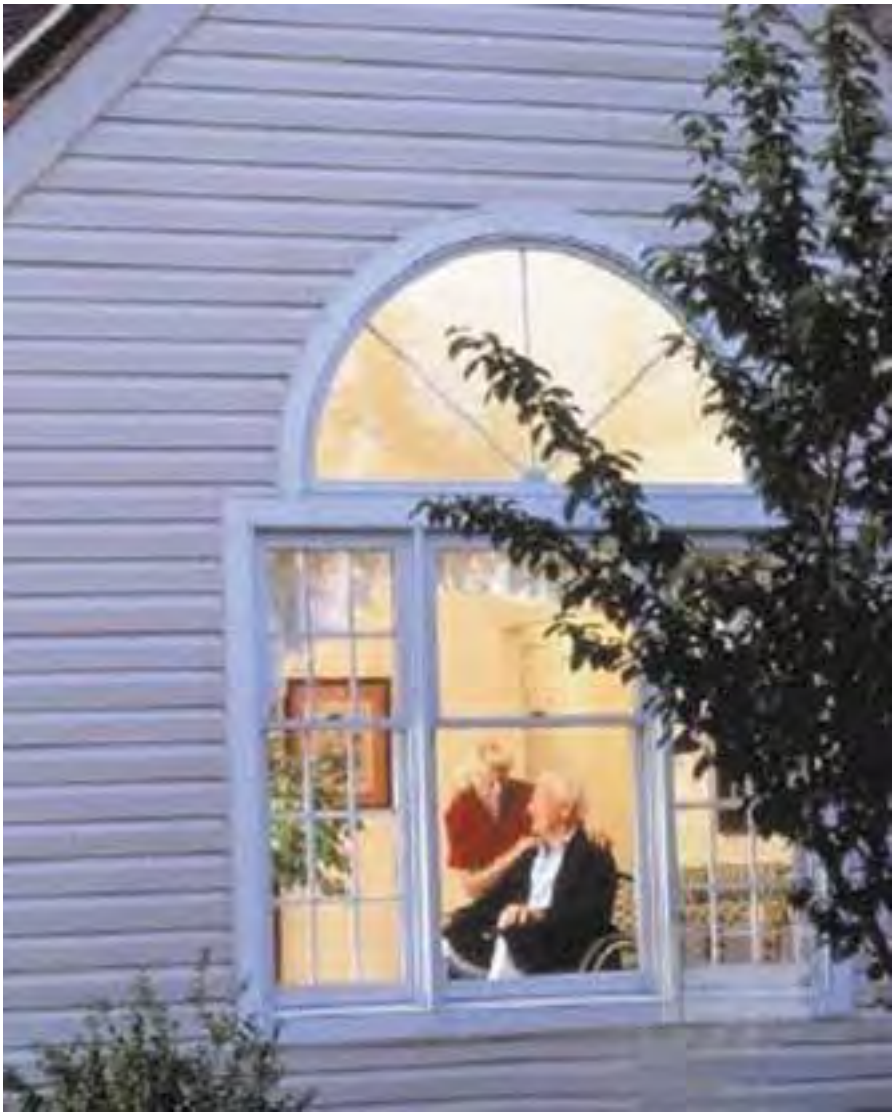
While the number of nuclear plants has declined due to retirements, nuclear electricity generation has steadily increased in recent years. Several factors have created a more favorable environment for nuclear energy: safe, standardized plant designs; an improved licensing process; effective safety oversight by the Nuclear Regulatory Commission (NRC); the advent of new technologies; and uncertain, volatile natural gas prices. This more favorable environment has resulted in increased re-licensing of nuclear plants and the consolidation of several plants in the hands of fewer, more experienced operators.

Figure 1-3
Fuel Sources for Electricity Generation in 2000



Electricity is a secondary source of energy, generated through the consumption of primary sources. Coal and nuclear energy account for over 70 percent of U.S. electricity generation.

Source: U.S. Department of Energy, Energy Information Administration.



Many Americans received high heating bills this winter as a result of sharp increases in natural gas prices.

The nuclear industry is closely regulated by the NRC, which provides oversight of the operation and maintenance of these plants. This oversight includes a comprehensive inspection program that focuses on the most significant potential risks of plant operations, and features full-time resident inspectors at each plant, as well as regional inspectors with specialized expertise. In addition to rigorous inspection criteria, the installation of new design features, improvements in operating experience, nuclear safety research, and operator training have all contributed to the nuclear industry's strong safety record.

An important challenge to the use of nuclear energy is the issue of safe and timely long-term storage of spent nuclear fuel and high- and low-level radioactive waste. Currently, no plans exist to construct any new nuclear plants. However, due to more favorable conditions, the decline in nuclear energy generation has not been as rapid as was predicted only a few years ago, as evidenced by increased re-licensing.

Natural Gas

Natural gas is the third-largest source of U.S. electricity generation, accounting for 16 percent of generation in 2000. Under existing policy, natural gas generating capacity is expected to constitute about 90 percent of the projected increase in electricity generation between 1999 and 2020. Electricity generated by natural gas is expected to grow to 33 percent in 2020—a growth driven by electricity restructuring and the economics of natural gas power plants. Lower capital costs, shorter construction lead times, higher efficiencies, and lower emissions give gas an advantage over coal and other fuels for new generation in most regions of the country.

However, natural gas is not just an electricity source. It is used in many different ways, including as vehicle fuel, as industrial fuel, and in our homes. In addition, natural gas is used as a feedstock during the manufacturing process of such products as chemicals, rubber, apparel, furniture, paper, clay, glass, and other petroleum and coal products. Overall, natural gas accounts for 24 percent of total U.S. energy consumed and for all purposes 27 percent of domestic energy produced.

Eighty-five percent of total U.S. natural gas consumption is produced domestically. The import share of consumption rose from 5 percent in 1987 to 15 percent in 2000, and net imports have comprised more than 50 percent of the growth in gas demand since 1990. Canada, with very large gas supplies and easy pipeline access to the lower 48 states, accounts for nearly all U.S. natural gas imports. Unlike oil, almost all natural gas is produced and sold within the same region. Therefore, prices are determined by regional, rather than global, markets.

In 2000, natural gas prices moved

sharply higher after fifteen years of generally flat prices. Futures prices surged by 320 percent in 2000 to an all-time high of $9.98 per million Btus in late December 2000—nearly five times higher than the $2.05 per million Btu average from 1991 to 1999. While prices have declined since the beginning of 2001, they remain much higher than recent levels.

Between 2000 and 2020, U.S. natural gas demand is projected by the Energy Information Administration to increse by more than 50 percent, from 22.8 to 34.7 trillion cubic feet. Others, such as Cambridge Energy Research Associates, expect gas consumption to increase by about 37 percent over that period. Growth is projected in all sectors—industrial, commercial, residential, transportation, and electric generation. More than half of the increase in overall gas consumption will result from rising demand for electricity generation.

Although high natural gas prices have negative effects on consumers, businesses, industries, and the economy as a whole, they also promote more rapid development and adoption of new energy efficient technologies, investment in distribution systems, and greater investment in exploration and development. Although these market responses do not occur rapidly enough to prevent near-term price spikes, over time, they help to hold down prices.

As a result of the sharp increase in natural gas prices, many consumers received historically high utility bills this winter. The price spike has had a particularly severe impact on low-income consumers who use natural gas for heating. In recent months, 5 million consumers have applied for federal and state assistance to pay their heating bills—an increase of 1 million consumers over last year.

The projected rise in domestic natural gas production—from 19.3 trillion cubic feet in 2000 to 29.0 trillion cubic feet in 2020—may not be high enough to meet projected demand. In the near term, incremental production of natural gas is expected to come primarily from unconventional sources in the Rocky Mountain, Gulf Coast, and mid-continent regions; the North Slope of Alaska; and the offshore Gulf of Mexico. Onshore federal lands currently contribute about 10 percent of U.S. production, and federal offshore production contributes about 26 percent.

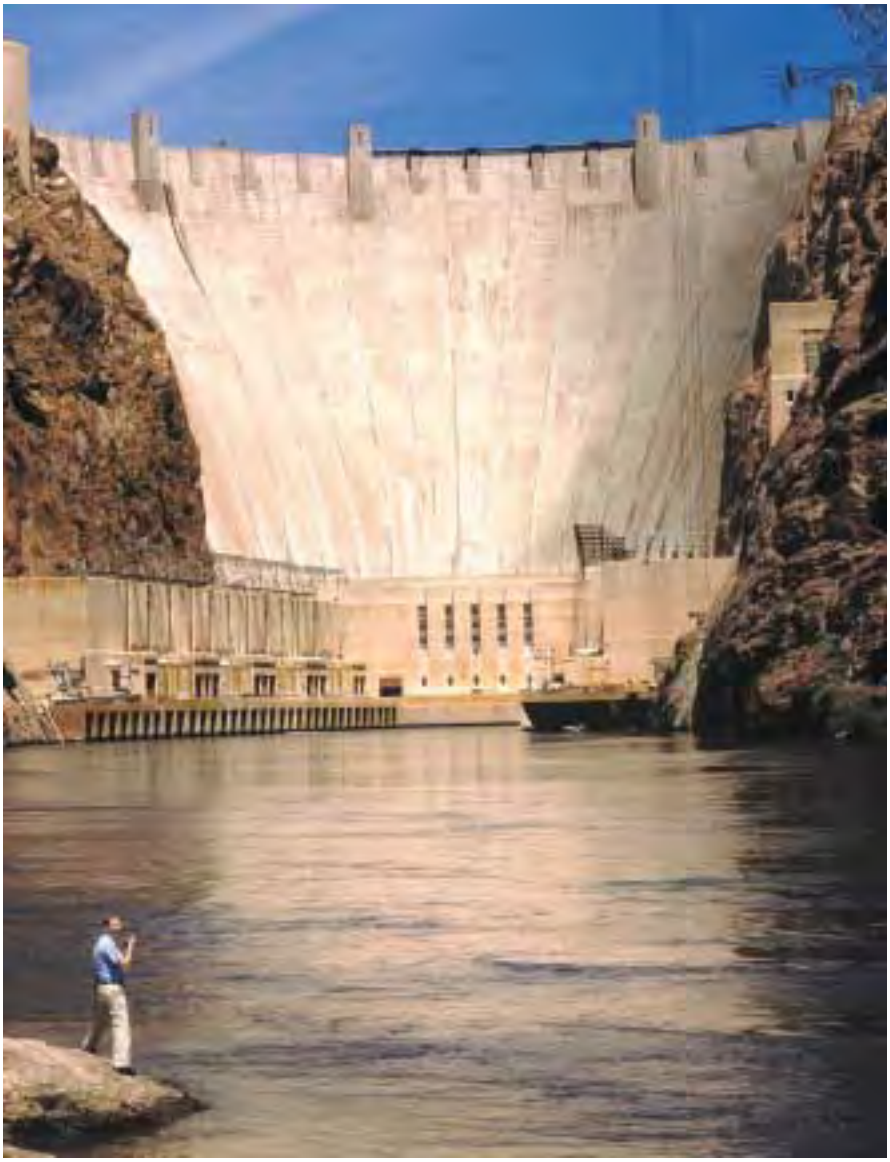
The most significant long-term challenge relating to natural gas is whether adequate supplies can be provided to meet sharply increased projected demand at reasonable prices. If supplies are not adequate, the high natural gas prices experienced over the past year could become a continuing problem, with consequent impacts on electricity prices, home heating bills, and the cost of industrial production. These concerns will redouble if policy decisions sharply reduce electricity generation by any other source, since it is doubtful that natural gas electricity generation could expand to the extent necessary to compensate for that loss of generation.

To meet this long-term challenge, the United States not only needs to boost production, but also must ensure that the natural gas pipeline network is expanded to the extent necessary. For example, although natural gas electricity generation in New England is projected to increase by 16,000 MW through 2000, bottlenecks may block the transmission of necessary supplies. Unless pipeline constraints are eliminated, they will contribute to supply shortages and high prices, and will impede growth in electricity generation.

Hydropower

Hydropower is the fourth-largest source of U.S. electricity generation, accounting for about 7 percent of total generation in 2000. In some regions of the country, such as the Northwest and New York, hydropower makes a much bigger contribution to electricity generation. Although the United States is second only to Canada in hydropower generation, hydropower generation has remained relatively flat in the United States for years.

Hydropower has significant environmental benefits. It is a form of low-cost electricity generation that produces no emissions, and it will continue to be an important source of U.S. energy for the future. Given the potential impacts on fish and wildlife, however, it is important to ef-



Hydropower is the fourth-largest source of U.S. electricity generation. The most significant challenge confronting this source of energy is regulatory uncertainty regarding the federal licensing process.

ficiently and effectively integrate national interests in both natural resource preservation and environmental protection with energy needs.

There are two categories of hydropower projects in the United States: (1) those operated by federal electric utilities, such as the federal power marketing administrations (Bonneville, Western, Southwestern, and Southeastern); and (2) the approximately 2,600 non-federal hydropower dams licensed or exempted by the Federal Energy Regulatory Commission (FERC). The federal utilities have large hydropower systems operated by the Bureau of Reclamation and Army Corps of Engineers, and play an important role meeting electricity demand, especially in the Northwest and the West. Hydropower projects operate with multiple purposes, such as electricity generation, flood control, navigation, and irrigation.

Although most potential for hydropower has already been developed, there is some undeveloped hydropower capacity in the United States. Much of this capacity could be expanded without constructing a new dam.

The most significant challenge confronting hydropower is regulatory uncertainty regarding the federal licensing process. The process is long and burdensome, and decision-making authority is spread across a range of federal and state agencies charged with promoting different public policy goals. Reforms can improve the hydropower licensing process, ensuring better public participation, ensuring that effective fish and wildlife conditions are adopted, and providing interagency resolution before conflicting mandatory license conditions are presented. The licensing process needs both administrative and legislative reforms. In addition, FERC should be encouraged to adopt appropriate deadlines for its own actions during the process.

Oil

Oil accounts for approximately 3 percent of electricity generation. Oil is used as a primary source to fire electricity generation plants in some regions. Specifically, oil is an important source of electricity in Hawaii, Florida, and some northeastern states. Oil can also be used an additional source of fuel for electricity generation in plants that can use either natural gas or oil. However, electricity generation from oil is projected to decline to about one-half of one percent of total electricity generation by 2020.

Renewable Energy: A Growing Resource

Renewable energy technologies tap natural flows of energy—such as water, wind, solar, geological, and biomass sources—to produce electricity, fuels, and heat. Non-hydropower renewable electricity generation is projected to grow at a faster rate

than all other generation sources, except natural gas. These sources of energy are continuously renewable, can be very clean, are domestically produced, and can generate income for farmers, landowners, and others. Although its production costs generally remain higher than other sources, renewable energy has not experienced the price volatility of other energy resources.

Non-hydropower renewable energy sources currently account for only about 4 percent of total energy consumption and 2 percent of total electricity generation. The sources of non-hydropower renewable electricity generation are biomass (the direct combustion of plant matter and organic residues, such as municipal solid waste use); geothermal (use of naturally occurring steam and hot water); wind; and solar. Biomass and geothermal account for most renewable electricity generation.

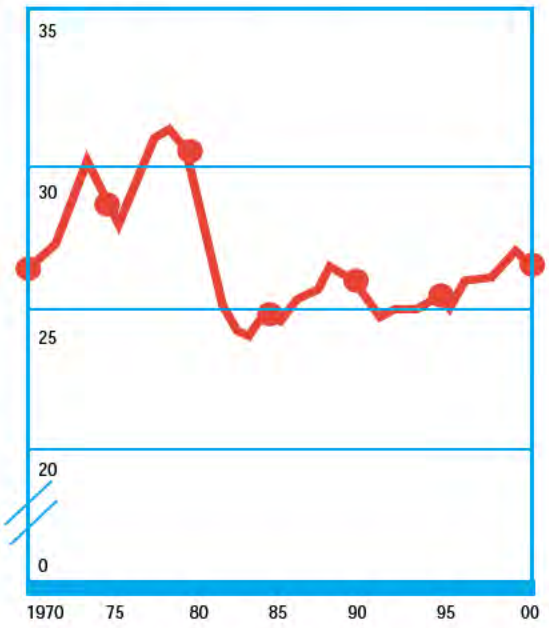
The most important long-term challenge facing renewable energy remains economic. Renewable energy costs are often greater than those of other energy sources. However, these costs have declined sharply in recent years, due to improved technology. If this trend continues, renewable energy growth will accelerate. By 2020, non-hydropower renewable energy is expected to account for 2.8 percent of total electricity generation.

Transportation Energy Needs

Oil is the nation's largest source of primary energy, serving almost 40 percent of U.S. energy needs. In 2000, the United States consumed an average of 19.5 million barrels of oil every day. Transportation fuels account for about two-thirds of our oil consumption, and the industrial sector for 25 percent. Residential and commercial uses, such as heating oil and propane—important fuels in the Northeast and Midwest—account for most of the rest.

The share of oil in U.S. energy supply has declined since the early 1970s, the result of growth in other fuels, particularly coal and nuclear. Per capita oil consumption, which reached a peak in 1978, has fallen by 20 percent from that level (Figure 1-4).

Figure 1-4
U.S. Per Capita Oil Consumption: 1970–2000



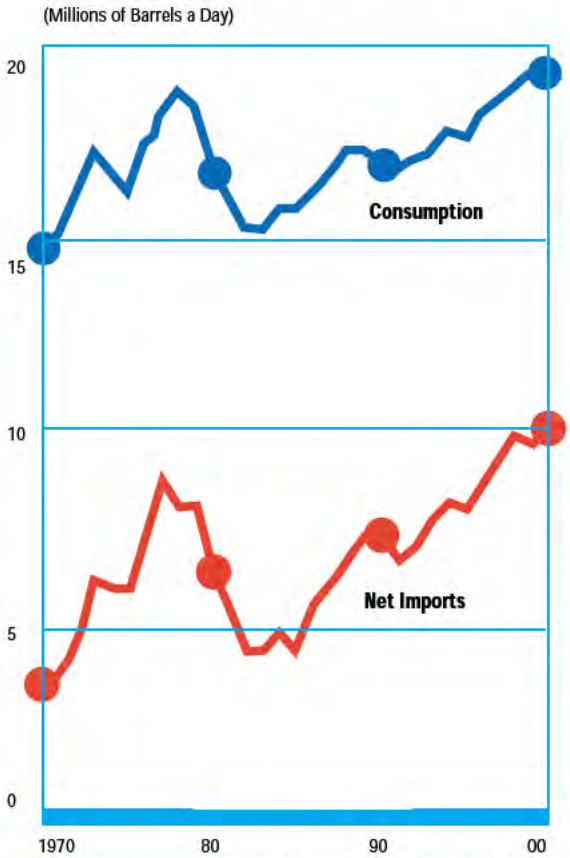
Per capita oil consumption reached a peak in 1978 of 31 barrels. it has fallen by 20 percent since then to 26 barrels per capita.

Source: U.S. Department of Energy, Energy Information Administration

Renewable energy technologies tap natural flows of energy to produce electricity, fuels, and heat.
U.S. Department of Energy, National Renewable Energy Laboratory



Figure 1-5
Dependence on Foreign Sources of Oil



U.S. dependence on oil imports is a serious long-term challenge. The economic security of our nation and our trading partners will remain closely tied to global oil market developments.

Source: U.S. Department of Energy, Energy Information Administration.

In 2020, oil is projected to account for roughly the same share of U.S. energy consumption as it does today.

The United States has been a net importer of energy since the 1950s, and U.S. dependence on imports has grown sharply since 1985 (Figure 1-5). Today, oil accounts for 89 percent of net U.S. energy imports. Net oil imports account for most of the rise in energy imports since the mid-1980s, and have grown from about 4.3 million barrels per day (bpd) in 1985 to 10 million bpd in 2000.

World oil prices have been marked by notable price volatility over the past several years. For example, the average initial purchase price of crude oil rose from $8.03 a barrel in December 1998 to $30.30 a barrel in November 2000. Spot prices rose even higher. This dramatic price swing was the product of several events. A series of production cuts by the Organization of Petroleum Exporting Countries (OPEC) in 1998 and 1999 sharply curtailed global oil supplies. At the same time, rebounding demand for oil in Asia following roughly two years of economic weakness, and rapid economic growth in the United States boosted oil consumption and squeezed supplies even further. By September 2000, oil prices peaked as markets faced limited supply of crude and petroleum products



U.S. Department of Transportation

Domestic oil supply cannot be increased unless several access and infrastructure challenges are addressed. For example, U.S. refining and pipeline capacity has not kept pace with increasing demand for petroleum products.

ahead of the winter season, when demand is typically higher. In December 2000, oil prices fell after the market absorbed the impact of a series of OPEC production increases.

This recent price volatility illustrates the effect of intermittent market power exerted by cartel behavior in a global petroleum market. Moreover, prices are set in a market where supply is geographically concentrated. Almost two-thirds of world proven reserves are in the Middle East. Elsewhere, Central and South America account for 9 percent; Africa, 7 percent; North America, 5 percent; Eastern Europe and the former Soviet Union, 5 percent; the rest of Asia, 4 percent; and Western Europe, 2 percent. OPEC's huge oil reserves and production capacity and its periodic efforts to influence prices add to volatility in the market.

Oil prices are expected to remain high through 2002, affecting the cost of transportation, heating, electricity generation, and industrial production. High oil prices mean high prices for petroleum products, such as gasoline, diesel fuel, heating oil, propane, and jet fuel. The summer 2001 base case average gasoline price from the Department of Energy *Short-Term Energy Outlook* is $1.49 per gallon. However, prices have risen more rapidly than anticipated since the report's release, and a much higher summer average in the range of $1.50 to $1.65 per gallon is likely. Some areas have already experienced gasoline prices above $2.00 per gallon. Gasoline inventories going into the driving season are projected to be lower than last year, which could set the stage for regional supply problems that once again create significant price volatility in gasoline markets.



Because the United States is a mature oil-producing region, production costs are often higher than in foreign countries.

Price Volatility in Gasoline Markets

During the early summer of 2000, low inventories set the stage for a gasoline price run-up in the Midwest. Several pipeline and refinery problems sent marketers scrambling for limited supplies of both reformulated gasoline (RFG) and conventional gasoline, driving prices up rapidly. In Chicago, the spot price for blend stock for RFG, excluding ethanol, doubled in about six weeks, from 83 cents per gallon on April 25 to $1.65 on June 7. Spot prices then fell back over the next five weeks to 84 cents on July 12 as extra supply began arriving. Retail regular-grade RFG prices in the Midwest rose from $1.47 on April 24 to just over $2.00 per gallon on June 19, before falling back to $1.43 by July 24, showing the typical tendency of

retail prices to lag spot price changes.

Refiners face additional challenges as a result of various state and local clean fuel requirements for distinct gasoline blends ("boutique fuels"). These different requirements sometimes make it difficult, if not impossible, to draw on gasoline supplies from nearby areas or states to meet local needs when the normal supply is disrupted.

In 2000, very low inventories of gasoline and other refined products on the U.S. East and Gulf coasts increased the market's susceptibility to external shocks, such as operating problems in refineries or pipelines, or short-term surges in demand. Last winter, heating oil prices were at near-record levels. During 2000, the federal government reduced the vulnerability of the Northeast to heating oil shortages, such as those experienced in January 2000, by creating a 2-million-barrel heating oil reserve in New Jersey and Connecticut.

Because the United States is a mature oil-producing region, production costs are often higher than in foreign countries, particularly OPEC countries. In addition, access to promising domestic oil reserves is limited. U.S. oil production in the lower 48 states reached its peak in 1970 at 9.4 million bpd. A surge in Alaskan North Slope oil production beginning in the late 1970s helped postpone the decline in overall U.S. production, but Alaska's production peaked in 1988 at 2 million bpd, and fell to 1 million bpd by 2000. By then, U.S. total oil output had fallen to 5.8 million bpd, 39 percent below its peak.

By 2020, U.S. oil production is projected to decline from 5.8 to 5.1 million bpd under current policy. However, oil consumption is expected to rise to 25.8 million bpd by 2020, primarily due to growth in consumption of transportation fuels. Given existing law, production from offshore sources, particularly the Gulf of Mexico, is predicted to play an increasingly important role in the future, accounting for a projected high of 40 percent of domestic oil production by 2010, up from 27 percent today. Technological advances can mitigate the decline in U.S. oil production by enhancing recovery from domestic oil reserves and lowering production costs.

Our projected growing dependence on oil imports is a serious long-term challenge. U.S. economic security and that of our trading partners will remain closely tied to global oil market developments. Without a change in current policy, the share of U.S. oil demand met by net imports is projected to increase from 52 percent in 2000 to 64 percent in 2020. By 2020, the oil for nearly two of every three gallons of our gasoline and heating oil could come from foreign countries. The sources of this imported oil have changed considerably over the last thirty years, with more of our imports coming from the Western Hemisphere. Despite progress in diversifying our oil suppliers over the past two decades, the U.S. and global economies remain vulnerable to a major disruption of oil supplies.

The Strategic Petroleum Reserve (SPR), the federal government's major tool for responding to oil supply disruptions, has not kept pace with the growth in imports. The number of days of net oil import protection provided by the Reserve declined from 83 days of imports in 1992 to 54 days of imports today. Net domestic oil imports have increased significantly since 1992, while the SPR's oil inventory actually decreased.

Domestic oil supply cannot be increased unless several access and infrastructure challenges are addressed. U.S. refining and pipeline capacity has not kept pace with increasing demand for petroleum products. Unless changes take place, the net effect will likely be increased imports, regionally tight markets, and circumstances in which prices for gasoline, heating oil, and other products rise independently of oil prices.

Greater price volatility for gasoline, diesel fuel, heating oil, propane, and jet fuel is likely to become a larger problem over time, unless additional refining capacity and expanded distribution infrastructure can be developed at the same time cleaner products are required. Increasing domestic oil production and reducing demand, particularly for transportation fuels, will re-

quire adoption of a comprehensive national energy policy.

Alternative Transportation Fuels

Development of alternative fuels such as ethanol and other biofuels (liquid fuels derived from organic matter, such as crops), natural gas, and electricity, can help diversify the transportation sector that is so reliant on oil.

Ethanol, a biofuel based on starch crops such as corn, is already making a significant contribution to U.S. energy security, displacing more oil than any other alternative fuel. Other biofuels, such as biodiesel, which can be made from soybean, canola oils, animal fats, and vegetable oils, are making an increasingly important contribution

The success of the federal alternative fuels program has been limited, however. The program focuses on mandating that certain fleet operators purchase alternative fueled vehicles. The hope was that this vehicle purchase mandate would lead to expanded use of alternative fuels. That expectation has not been realized, since most fleet operators purchase dual-fueled vehicles that operate on petroleum motor fuels. Reforms to the federal alternative fuels program could promote alternative fuels use, such as expanding the development of an alternative fuels infrastructure.

Summary of Recommendations

Taking Stock: Energy Challenges Facing the United States

★ The NEPD Group recommends that the President issue an Executive Order to direct all federal agencies to include in any regulatory action that could significantly and adversely affect energy supplies, distribution, or use, a detailed statement on: (1) the energy impact of the proposed action, (2) any adverse energy effects that cannot be avoided should the proposal be implemented, and (3) alternatives to the proposed action. The agencies would be directed to include this statement in all submissions to the Office of Management and Budget of proposed regulations covered by Executive Order 12866, as well as in all notices of proposed regulations published in the Federal Register.

★ The NEPD Group recommends that the President direct the executive agencies to work closely with Congress to implement the legislative components of a national energy policy.

★ The NEPD Group recommends to the President that the NEPD Group continue to work and meet on the implementation of the National Energy Policy, and to explore other ways to advance dependable, affordable, and environmentally responsible production and distribution of energy.

Note: All recommendations in this report are subject to execution in accordance with applicable law. Legislation would be sought where needed. Also, any recommendations that involve foreign countries would be executed in accordance with the customs of international relations, including appropriate diplomatic consultation.

Regional U.S. Energy Challenges

Midwest

Energy consumption in the Midwest is dominated by the industrial sector, the sector with the fastest-growing consumption rate through 2020. The transportation sector has the second-fastest consumption growth rate through 2020. States are affected by higher prices for natural gas, propane, and gasoline, and they expect gasoline price spikes this summer. Electricity supplies in some parts of the region may be tight during peak summer demand. High energy prices will drive up farm operating costs, particularly for fertilizer, irrigation, grain drying, and fuel for tractors.

Illinois consumers are reeling from high heating and cooling costs. Landlords are forced to pass on these costs in the form of higher rents. Farmers face low commodity prices, high fuel costs, and dramatically higher fertilizer costs. A key refinery is closing in part because of the cost of meeting cleaner-burning gasoline requirements.

Minnesota's residential electricity use has increased due to population growth and a healthy economy.

Iowa imports over 90 percent of its energy. Farmers are paying twice the 1999 price of fertilizer because of higher prices for natural gas, which is a major component in the fertilizer production.



West

Energy consumption in the West is dominated by the transportation sector, which is followed closely by the industrial sector. The region's drought emergency is exacerbating an already challenging energy picture. California is likely to experience more severe electricity blackouts this summer. The Pacific Northwest faces a major shortage of hydropower generation due to low water levels. Electricity prices will remain high in the West until more supply is added. Gasoline could be in short supply this summer in California and other states.

California's energy consumption has grown by about 7 percent a year, while production has remained flat. The point has been reached where demand is occasionally exceeding supply, which has caused rolling blackouts. The situation is likely to worsen this summer when demand will peak.

Oregon's lowest snow pack in history will result in the most severe short-term electricity problem in decades. The state will face high spot market prices and reports the highest gasoline prices in the country.

Washington businesses are closing down or cutting back on production. Electricity costs of $400 per unit compared to $35 a year ago contributed to the closure of a major paper plant employing 800 employees.

Colorado small business are suffering as well. A 169 percent jump in natural gas prices in one year may force small businesses to close.

Idaho utilities are offering to pay their irrigation customers to not farm portions of their fields to reduce electricity demand and make that saved power available for other local customers. The low snow pack has reduced water in river systems needed for hydropower generation.

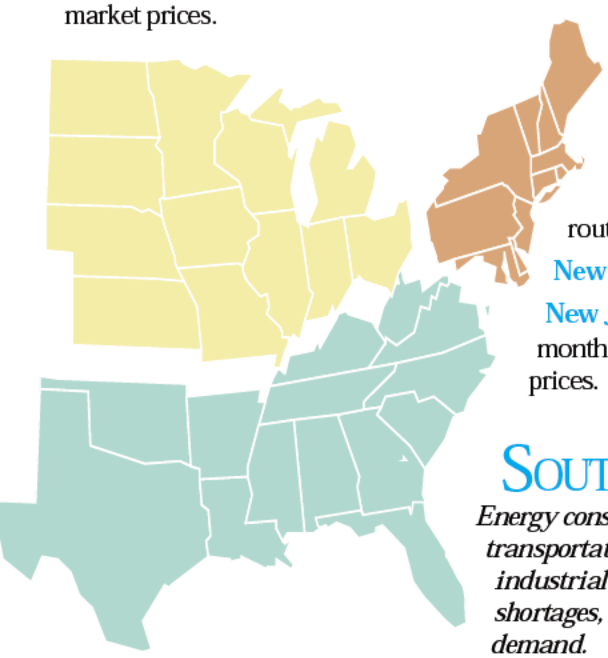
Hawaii's geographic isolation contributes to its many energy issues, such as importing 100 percent of its energy, its disproportionately high consumption of jet fuel and heavy reliance on tourism, and its dependence on imported oil for over 90 percent of its primary energy, the majority from sources in the Asia-Pacific region. Electricity is produced mainly from oil, including residuals and distillates from refineries and coal. Because the Islands' electric grids are not interconnected, electric utilities must operate with high reserve margins.

Nevada is covered in large part by federal lands that require federal approval for permitting new transmission and generation facilities. The permitting process can be protracted and cumbersome, despite efforts by federal agencies to streamline and coordinate. The desert climate requires both heating and cooling, the cost of which can be burdensome. While the desert climate is also conducive to geothermal, wind, and solar technologies, additional work is needed to make these technologies economically competitive.

Northeast

Energy consumption in the Northeast is dominated by the transportation sector. Forecasts developed by the Energy Information Administration indicate that the transportation sector will also remain the dominant sector with the fastest-growing consumption rate through 2020. Northeast states' energy challenges include reducing vehicle pollution and interstate transport of power plant emissions. Heavy dependence on heating oil results in disproportionate impacts during cycles of high prices. Energy supplies in the region are limited by electric transmission and gas pipeline bottlenecks.

New York is rushing to complete 11 small natural gas turbines to avoid blackouts in New York City this summer, where customers pay market prices.



Delaware needs upgraded transmission lines to handle increasing loads. Traditional distributed generation using diesel generators may address these shortfalls, but could raise environmental problems.

Connecticut expects no power shortages this summer, but brownouts are possible if there is a prolonged spike in energy use while power plants are shut down for routine maintenance.

New Hampshire must conserve power on hot days to avoid summer blackouts.

New Jersey regulators have had to allow utilities to raise natural gas rates by 2 percent a month through July 2001 to make up for money lost during the winter due to high fuel prices.

South

Energy consumption in the South is dominated by the industrial sector, followed by the transportation sector. The transportation sector, however, is expected to grow faster than the industrial sector through 2020. While no state in the region anticipates summer power shortages, electricity supplies in parts of the region may be tight during peak summer demand.

Arkansas' costs of natural gas and propane have doubled and then tripled, contributing to employee layoffs.

Oklahoma's second-largest industry is the oil and gas industry. The volatility of oil and gas markets can severely affect Oklahomans and the state's economy.

Striking Home

The Impacts of High Energy Prices on Families, Communities, and Businesses

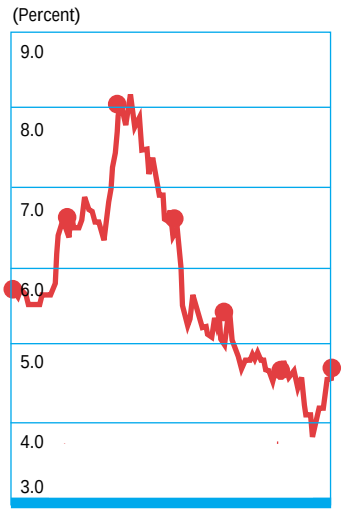
American families, communities, and businesses all depend on reliable and affordable energy for their health, safety, and livelihood. Energy is a critical component of nearly everything that affects our daily lives, from transportation to communication, from food production to medical services, and from air conditioning to heating. Americans expect these services to enhance our lives, and are keenly aware that each additional, unanticipated energy expense is a decrease in funds available for other needs.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to explore potential opportunities to develop educational programs related to energy development and use. This should include possible legislation to create public education awareness programs about energy. Such programs should be long-term in nature, should be funded and managed by the respective energy industries, and should include information on energy's compatibility with a clean environment.

Figure 2-1

Income Spent on Energy



Until recently, the share of disposable household income spent on energy steadily declined, falling to a low of 3.8 percent at the end of 1998. Higher prices for oil and other energy products and record cold temperatures in late 2000 bumped this share up to 4.8 percent in the fourth quarter.

Note: Plotted quarterly through the fourth quarter of 2000.

Source: U.S. Department of Commerce, Bureau of Economic Analysis.

Impacts of High Energy Prices on the Daily Lives of Americans

Many American families and businesses have already felt the strain of rising prices and unreliable energy supplies. Every time energy prices rise, American families have fewer dollars available to meet their needs. Low-income households, energy-intensive industries, and farmers generally find it difficult to make rapid adjustments to energy price increases.

Rising oil prices act like a tax by foreign oil exporters on Americans. Changing energy prices impose economic costs, such as forcing plants to change schedules, replace machinery, or even shut down. These costs can eventually impact economic growth. So far, increased capital investment by domestic energy producers has offset only a small part of the dampening effects of higher energy costs on consumer spending.

Families

Energy bills for the 74 million middle-class American households consist primarily of home and transportation related expenses. Heating and cooling expenses represent about 40 percent of household energy costs. Other energy expenses include costs for lighting, hot water, appliances, and transportation.

For almost twenty years, the share of household income that Americans spent on their energy needs steadily declined. However, between 1998 and the end of last year, family spending on energy rose by more than 26 percent, from 3.8 to 4.8 percent of after-tax income (Figure 2-1).

Last winter, heating bills for many families tripled. Roughly 50 percent of American families heat their homes with natural gas. Because the last two months of 2000 were particularly cold in some parts of the country, heating bills increased significantly relative to the previous winter. Last winter, average natural gas heating costs in the Midwest increased by 73 percent, from $540 to $933. New Englanders' heating bills rose by 27 percent, from $760 to $967.





Higher energy prices have forced some energy-intensive manufacturing industries to halt or scale back production and lay off workers.

Many working households can usually accommodate such increases in energy by cutting back on other needs. However, low-income households often have more difficult choices to make. Energy costs for an average low-income household could total 14 percent of family income during the winter of 2000–01, up from about 11 percent for the previous winter. In contrast, energy costs typically represent only about 4 percent of a middle-class family's household budget.

The Low Income Home Energy Assistance Program (LIHEAP) is a federal block grant program that helps low-income consumers pay their energy bills. Last winter, 1.2 million more American families applied for LIHEAP assistance to pay their heating bills, bringing the total close to 5 million American families—up by 26 percent over last year's 3.9 million applicants. As many as 3.6 million families in eighteen states and the District of Columbia risk being unable to pay their bills and having their energy cut off because of the effects of rapidly increasing energy costs.

Recommendations:

★ The NEPD Group recommends that the President take steps to mitigate impacts of high energy costs on low-income consumers. These steps would include:

- Strengthening the Low Income Home Energy Assistance Pro gram by making $1.7 billion available annually. This is an increase of $300 million over the regular FY 2001 appropriation.
- Directing the Secretaries of Interior and Health and Human Services to propose legislation to bolster LIHEAP funding by using a portion of oil and gas royalty payments.
- Redirecting royalties above a set trigger price to LIHEAP, whenever crude oil and natural gas prices exceed that trigger price, as determined by the responsible agencies.

★ The NEPD Group recommends that the President increase funding for the Weatherization Assistance Program by $1.2 billion over ten years. This will roughly double the spending during that period on weatherization. Consistent with that commitment, the FY 2002 Budget includes a $120 million increase over 2001. The Department of Energy will have the option of using a portion of those funds to test improved implementation approaches for the weatherization program.

★ The NEPD Group recommends that the President support legislation to allow funds dedicated for the Weatherization and State Energy Programs to be transferred to LIHEAP if the Department of Energy deems it appropriate.

The low-income elderly are particularly vulnerable to disruptions in energy supply. If they keep their homes at a reasonable temperature, the high cost of electricity may make it difficult for them to pay their higher electricity bills. This could further result in an elimination of service. Another summer of very hot weather and high energy bills could cause serious health problems for some Americans, particularly those sensitive to high temperatures.

The Department of Energy's Weatherization Assistance Program has reduced the heating and cooling costs of low-income households by weatherizing more than 5 million homes since its inception in 1976. The President has requested $1.2 billion in additional funding for this program over ten years, roughly double the current level of spending. Consistent with that commitment, the 2002 budget will include a $120 million increase over 2001.

The Department of Energy's Weatherization Assistance Program

The energy burden on low-income households, as a proportion of income, is four times greater than for other American households. The Weatherization Program provides grant funding for a network of all states and some 970 local weatherization agencies to provide insulation, duct system improvements, furnace upgrades, and other cost-effective, energy-saving improvements based on the energy needs of each home weatherized. Currently, each dollar spent on home weatherization generates $2.10 worth of energy savings over the life of the home; with additional economic, environmental, health, and safety benefits associated with the installations and resulting home improvements. Typical savings in heating bills, for a natural gas heated home, grew from about 18 percent in 1989 to 33 percent today.

Businesses

For businesses, higher energy prices and disruptions in energy supply may increase inflation and reduce profits, production, investment, and employment. The im-

pact of higher energy prices takes two forms: the higher costs of paying for the energy to run the business, and the higher costs when raw fuel sources are used in manufacturing.

In some energy-intensive industries, rising energy prices have had a significant effect on product prices and operations. For instance, while nonenergy producer prices at the intermediate stage of processing have risen by only 3.6 percent since December 1998, prices of industrial materials and plastic resins, which use petroleum inputs, are up 14 and 23 percent, respectively. DuPont, the leading U.S. producer of plastics, chemicals, and fibers derived from oil and natural gas, faced an increase of $1.3 billion in raw material costs last year, the largest increase in the industry in a decade. The company expects further disruptions this year due to high energy costs.

The Federal Reserve has reported that businesses have experienced higher energy costs for a number of months, but have been unable to pass these increases on to customers due to intense foreign and domestic competition and slowing demand. On March 7, 2001, the Federal Reserve reported that businesses across the country experienced higher fuel and other energy costs in February 2001, but most businesses were unwilling or unable to pass these costs on to consumers.

This absorption of much of the higher costs of energy has deteriorated the profit margins of many businesses. About one-quarter of the increase in total unit costs of nonfinancial, nonenergy corporations in the final quarter of last year reflected a rise in energy costs. A more moderate pace of consumer spending, due in part to higher energy prices (natural gas in particular) also contributed to the margin squeeze. The reduction in businesses' purchasing power has also constrained outlays for plants and equipment and most likely intensified the slowdown in business investment that occurred in the last half of 2000.

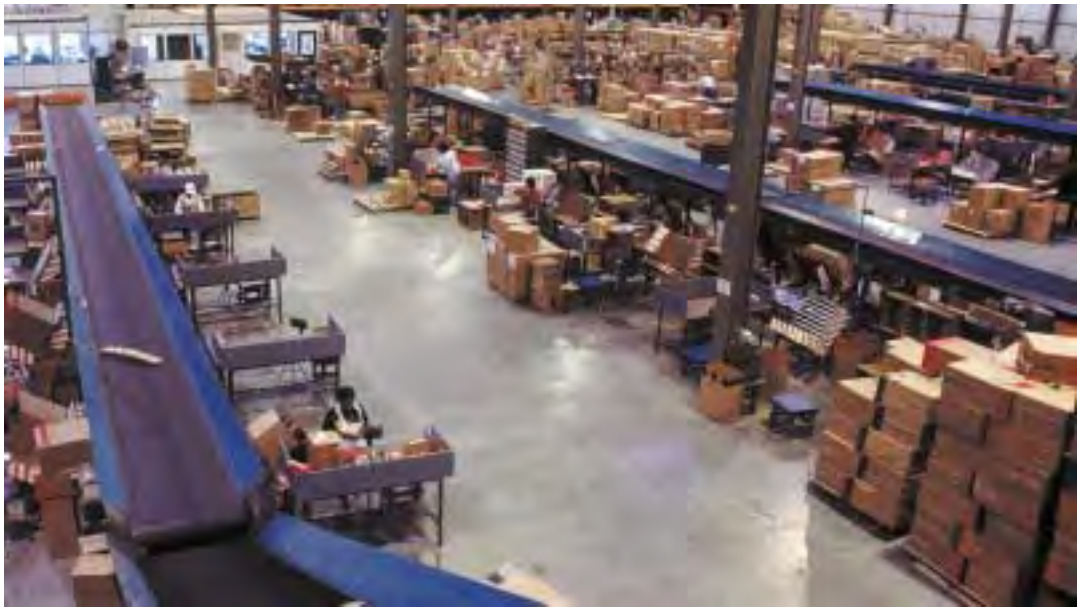
Energy-intensive manufacturing industries are very sensitive to changes in energy prices, and adjust their production accordingly. Some companies have been forced to halt or scale back production and lay off workers. Others have deemed it more profitable to sell their energy than to produce their products. In the Pacific Northwest, Georgia-Pacific's paper mill closed down and laid off 800 workers until diesel generators could be installed. In recent months, the company's average power costs soared from $1.2 million to $10 million.

For other industries, such as computer-driven service industries, energy is not an important component of the total cost. However, many such businesses require a high-quality, reliable source of power. Even a brief loss of power can impose significant costs on high-technology firms.

Energy supply disruptions also impose costs on firms when products or prod-



Disruptions in the supply of energy impose hardships on businesses when products or product inputs are damaged or destroyed, or when production runs are interrupted.



Many companies have been unable to pass higher energy costs on to their customers, which has sharply reduced their profit margins.



Farmers have been hit especially hard by higher fuel and oil prices, which accounted for over a third of the rise in the cost of running their farms.

uct inputs are damaged or destroyed, or when production runs are interrupted. For example, a survey of small businesses conducted by the National Federation of Independent Business in February, 2001, found that more than half of the firms surveyed that had experienced blackouts this year in California were forced to reduce or shut down business operations altogether during the blackouts. About one-third lost sales, almost 21 percent said materials were damaged or destroyed, and nearly 40 percent had to absorb wage costs for work that was not completed.

For businesses that seek to mitigate energy price volatility, an important factor is access to derivatives markets. Both exchange-traded futures and over-the-counter derivative contracts allow firms to substantially reduce their exposure to changes in energy prices. A wide variety of highly liquid futures contracts on energy products such as oil, natural gas, and electricity allow energy users and market participants to reduce or add financial exposure to energy prices. More sophisticated and customizable products are available in the over-the-counter derivative markets. As these markets become increasingly liquid and efficient, more firms will take advantage of these products, reducing the economy's sensitivity to shifts in energy prices. However, most small businesses currently lack the resources or sophistication to take advantage of these products, and will therefore remain vulnerable to rising energy costs. The U.S. government should continue to support the development of efficient derivatives markets.

Figure 2-2

Farmers Are Being Squeezed by Energy Prices

(Index: 1990–92 = 100)



Costs for fuel, fertilizer, and electricity have boosted total prices paid by farmers, while prices farmers receive for their products have remained weak.

Note: Prices paid are for goods, services, interest, taxes, and wages; prices received are for all farm products.

Source: U.S. Department of Agriculture.

Agriculture

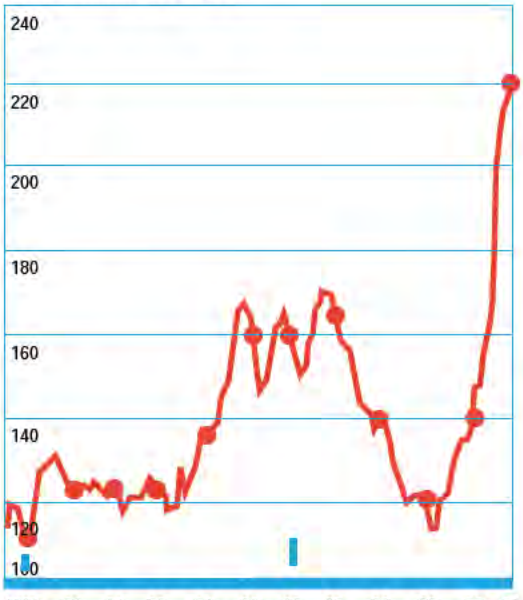
Farmers need ample, affordable energy to run their machinery and equipment. Today, farm production costs are rising sharply, while farm income remains low. Increasing oil prices and interest rates, along with higher prices for other production inputs (including hired labor), boosted farmers' production expenses by 4 percent, or $7.6 billion, in 2000. The rise in farm production expenses has occurred at a time of continued weakness in the prices farmers receive for their products (Figure 2-2).

Higher fuel and oil prices accounted for over one-third of the increase in farm

Figure 2-3

Farm Costs Are Increasing

(Index: December 1979 = 100)



Rising energy prices had a significant effect on product prices in some industries that are heavily dependent on energy inputs. The most dramatic example is the 90 percent increase in the price of nitrogenous fertilizer since December 1998.

Source: U.S. Department of Labor.

production costs. Retail diesel prices this past winter were $1.60 a gallon, compared to about $1.40 a year ago and only $1.00 two years ago. Propane prices were over $1.60 a gallon this winter, compared to $1.10 a year ago. And, natural gas prices hit $10.00 per million Btus in January, after averaging about $2.50 for most of 1998–99. Although natural gas prices have declined, they remain much higher than earlier levels.

Natural gas is an important component of farm production costs. For example, it is used to dry grain, heat farm buildings, and run food-processing equipment. Heating costs for poultry producers soared last winter, sharply reducing earnings.

Natural gas also is a major component in the production of fertilizers, pesticides, and other farm chemicals. It accounts for 70 to 90 percent of the cost of producing anhydrous ammonia, a key source of nitrogen fertilizer. Surging natural gas prices have boosted the price of nitrogenous fertilizer by 90 percent since 1998 (Figure 2-3). During last December and January, several nitrogen production plants shut down, and capacity utilization fell to 50 percent. Anhydrous ammonia recently sold for $330 a ton in the Midwest, compared to $210 a ton for all of 2000 and $160 to $170 a ton at the start of 2000.

Depending on the region of the country and type of farming enterprises, energy-related expenses range from 10 to 30 percent of operating costs for producing major crops. Farm operating costs are highest where fertilizer use is heaviest and natural gas is used for irrigation pumps, such as wheat, cotton, and corn farms in the West and southwestern plains states. Costs are high for greenhouse and nursery crops that use natural gas for heating. Perishable crops also face problems, as energy costs in processing are markedly higher.

Most of California's 9.5 million irrigated acres use electricity to pump water. In addition to higher bills, California farmers will likly face rolling blackouts this summer, which may disrupt farming and processing operations. Low stream flows in the West this year may lead to more pumping of ground water, which will add to irrigation costs in the West. As a result, the costs of California's agricultural products may rise significantly.

In 2001, farmers' total cash production expenses are forecast to increase by an additional $1.5 billion to a record $179.5 billion.

Farm production costs are rising sharply, while farmers' incomes remain low. Depending on the region of the country and type of farming enterprises, energy-related expenses range from 10 to 30 percent of operating costs for producing major crops



Even though total planted acreage is expected to fall this year, higher natural gas prices will raise expenses for nitrogen fertilizer. At the same time, net cash farm income is projected to decline from $56.4 billion in 2000 to under $51 billion in 2001, as production expenses continue to rise.

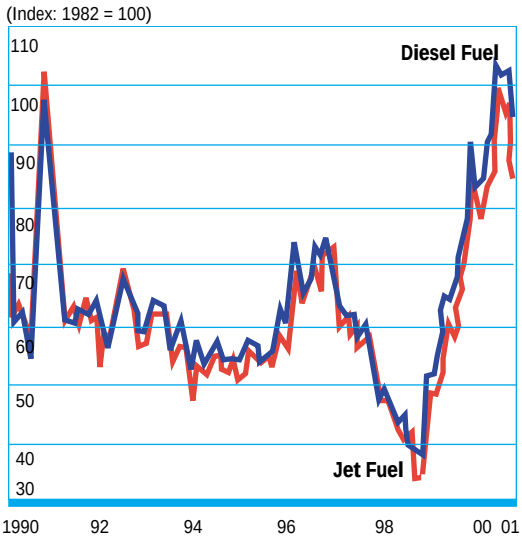
Taken together, fertilizer, fuel, and electricity costs for farmers are forecast to reach $24 billion for 2001, up by about 28 percent from $18.7 billion in 1999. This increase is about 9 percent of U.S. net cash farm income, and that share could be much higher for many individual commodities.

Transportation

The transportation sector accounts for nearly 30 percent of total U.S. energy consumption. The major transportation fuel sources are petroleum-based gasoline and diesel, jet, and marine-mode bunker fuels. Natural gas pipelines are used for product distribution, and electricity is the primary source of power for rail transit and liquid pipeline transmission and distribution.

During 2000, oil prices surged to a nine-year high, and gasoline prices skyrocketed. On average, fuel prices rose by 30 to 40 cents a gallon from 1999 prices, resulting in sharp increases for most modes of transportation, with nearly a 60 percent increase in railroad diesel fuel prices.

Figure 2-4
Transportation Costs Are on the Rise



The recent 140 percent rise in producer prices for intermediate diesel and airline fuels has affected the price of passenger and freight transport.

Note: Plotted through February 2001.
Source: U.S. Department of Labor.



A recent study by a San Francisco Bay business group concluded that blackouts could cost California as much as $16 billion annually, and $5 billion in the Bay area alone.

Price spikes have hit the travel and trucking industries particularly hard and have led to the closure of some operations. Trucking bankruptcies are currently at an all-time high. Over 3,500 motor carrier operations failed in 2000, a dramatic increase over the previous record high of 2,700 motor carrier failures in 1997. Producer prices for intermediate diesel fuel and aviation fuel each rose by about 140 percent from a low in December 1998, affecting passenger and freight transport in the highway, airline, rail, and other transportation sectors (Figure 2-4).

For most transport operations, energy-related expenses were 7 to 14 percent of total operating costs in 1998–99. This share was expected to jump to 10 to 25 percent in 2000. Excluding private auto travel, U.S. passenger and freight operations in 1999 generated about $600 billion in annual revenue and paid approximately $60 billion for fuel and power. If the volume stayed the same in 2000, the various increases in fuel costs for each mode of transportation would yield a fuel bill of

about $80 billion—an increase of one-third over the prior year's bill.

Economic Impacts of California's Energy Crunch

In California, 43 percent of small businesses surveyed in February, 2001, said the power problem had dimmed their views about California as an attractive place for doing business. When asked whether they agreed with the statement, "The electricity problem has forced me to take concrete steps exploring the possibility of moving my business out of California," 18.3 percent of small business respondents said they either agreed or strongly agreed with the statement. More than 31 percent said they will probably or definitely cut back on planned business investment, and almost 20 percent are exploring a move to another state. Half of these small businesses concluded that blackouts would reduce their earnings.

The Silicon Valley Manufacturing Group recently estimated that its nearly 200 members lost over $100 million dollars because of one day of rolling blackouts in June 2000. Countless more millions of dollars have been lost by interruptible commercial power users. Fontana-based California Steel Industries estimates it lost $2.4 million in a single day after its interruptible power was cut off twice for a total of about 12 hours. A recent study by a San Francisco Bay business group concluded that blackouts could cost California as much as $16 billion annually, and $5 billion in the Bay area alone.

The example of California's utilities illustrates the potentially severe negative effects on companies whose business is highly sensitive to energy prices. In this instance, rising energy costs coupled with an inability to pass those costs along to customers has created a sharp increase in short-term liabilities. Pacific Gas & Electric has been forced to file for bankruptcy as a result, and Southern California Edison, while avoiding bankruptcy for the time being, has seen its access to credit markets disappear and the value of its financial assets plummet. Resulting concerns about solvency have led to a withdrawal of bank-lending facilities and supplier credit.

The situation in California is of particular concern because of the major role the state plays in the regional and national economies. California's economy is equivalent to about 13 percent of U.S. gross domestic product (GDP), and it has accounted for an even larger share of U.S. GDP growth in recent years. Some businesses and consumers have been affected by production losses, lost wages, and higher energy bills resulting from rolling blackouts and higher natural gas prices.

The power supply crunch in California and the West could affect the region's economy, as energy supply uncertainty could reduce investment in the region. California's troubles could also spill over to the national economy:

- California accounted for 11 percent of U.S. manufacturing output in 1998. Sectors in other regions that rely on those products, or that supply inputs to California manufacturers, may share any pain caused by the energy squeeze.
- Disruptions to California's economy could have negative impacts on our international trade. California accounts for over 16 percent of total U.S. commodity exports; nearly 25 percent of industrial equipment and computers, electronics, and instruments exports; and over 15 percent of farm commodity and food product exports.
- The credit problems of the California utilities have boosted commercial paper rates for all lower-rated borrowers, and liquidity in the commercial paper market has fallen. This will push some firms to seek other sources of financing, which can be more costly than commercial paper.

American consumers and businesses are best served when markets function freely. Free markets allow prices to reflect changes in demand and supply, and avoid subsidies, price caps, and other constraints.

Improvements in Energy Efficiency Can Help

Improved energy efficiency strengthens energy security. The 42 percent decline in the intensity of U.S. energy use since the energy crisis in 1973 reflects a combination of technological advances, conservation ef-



The Silicon Valley Manufacturing Group recently estimated that its nearly 200 members lost over $100 million dollars because of only one day of rolling blackouts in California.

Figure 2-5
Conservation Through Higher Efficiency
Energy Consumption per Dollar of Real GDP



Energy intensity is the amount of energy used to produce a dollar's worth of gross domestic product (GDP). As a result of the 42 percent decline in energy intensity since the first energy crisis in 1973, the U.S. economy is far better prepared to day than it was in the 1970s to ad just to energy price or supply shocks.

Note: Real GDP in 1996 chained dollars.
Source: U.S. Department of Energy, Energy Information Administration.

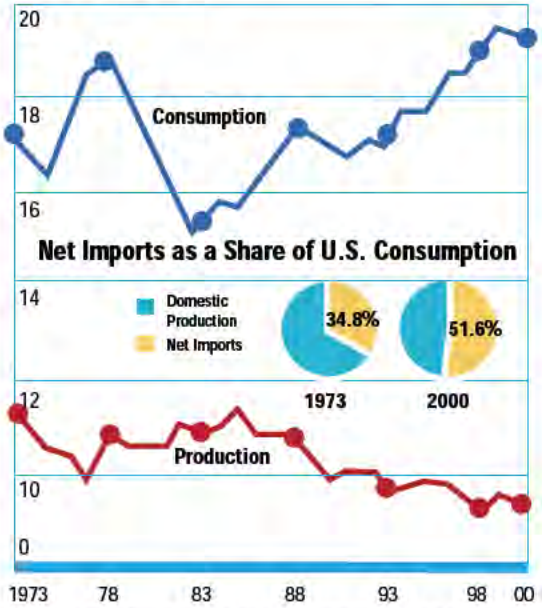
forts, regulatory action, market response, and a shift toward a service economy (Figure 2-5). Our improvements in energy efficiency have prevented our current energy problems from becoming worse.

The macroeconomic effects of a substantial rise in energy prices take two forms. First, to the extent that energy resources are imported, more U.S. dollars must be sent abroad to finance energy consumption, thus reducing funds available for investing in our own country. Second, higher prices cause dislocations among certain sectors of the economy, which could ultimately feed through to lower GDP growth and higher inflation.

Reliance on Foreign Energy

Between 1973 and 2000, U.S. dependence on foreign oil rose from about 35 percent to more than 52 percent of U.S. consumption (Figure 2-6). During the same period, the import share of natural gas consumption climbed from less than 5 percent to more than 15 percent and continues to rise.

Figure 2-6
Dependence on Oil Imports Is Rising
(Millions of Barrels per Day)



Over the past few decades, U.S. consumption of oil and petroleum products has increasingly outpaced domestic production. Today the United States imports over half of the oil it consumes—up from about 35 percent in the early 1970s.

Note: Petroleum includes both crude oil and petroleum products.
Source: U.S. Department of Energy, Energy Information Administration.

Figure 2-7
Oil Prices Have Risen Sharply
Monthly Spot Price of West Texas Intermediate Crude Oil
(Dollars per Barrel)



Despite the sharp rise in crude oil prices since late 1998, real prices still remain lower than at any time from 1974 to 1985.

Note: Real prices in 2000 dollars. Prices deflated using the Consumer-Price Index–Urban (CPI–U) Research Series for all items linked to CPI–U–X1 prior to December 1977.
Sources: Wall Street Journal; U.S. Department of Labor, Bureau of Labor Statistics.

Imports of energy products make up nearly 11 percent of all U.S. imports. By contrast, U.S. energy exports are relatively small. The energy trade deficit relative to our GDP represents the share of U.S. income that must be exported to purchase foreign fuel to meet domestic energy needs. The U.S. energy trade deficit in 2000 was about $120 billion, most of which was spent on oil imports.

As a share of GDP, the energy trade deficit had fallen to as low as 0.4 percent at the beginning of 1999, when prices for imported crude oil were less than $10 a barrel. However, by the end of 2000, these prices had tripled to more than $30 a barrel (Figure 2-7). As a result of both the oil price spike and growing U.S. demand, the energy deficit deteriorated significantly to 1.3 percent of GDP by the fourth quarter of last year—the largest deficit relative to GDP since the mid-1980s (Figure 2-8). The rise in oil prices alone has added about 0.7 percent of GDP to the U.S. trade deficit, compared to 0.9 percent in the euro currency area, and 0.8 percent in Japan.



Financial markets react to energy costs and the effect those energy costs have on both individual firms and sectors of the market.

Figure 2-8

The U.S.Energy Trade Deficit Has Worsened

(Percent)



The energy trade deficit relative to GDP represents the share of domestic income that must be exported to sup port domestic energy needs. For the past several years, the United States has been a net importer of energy prod ucts. As a consequence, our energy trade balance has been in deficit. By the fourth quarter of 2000, the energy deficit had deteriorated significantly to 1.3 percent of GDP—the largest since the mid-1980s.

Note: Plotted quarterly through the fourth quarter of 2000.-
Source: U.S. Department of Commerce, Bureau of Economic Analysis.-

Net U.S. oil imports are 4 billion barrels a year, which means that each $1 increase in the price of imported crude oil boosts U.S. expenditures by about $4 billion. Given these guidelines, the $20 per barrel increase from early 1999 to late 2000 translates into an export of roughly $80 billion a year (0.9 percent of GDP) when measured from the low price prevailing at the end of 1998.

Impacts of Energy Prices on Financial Markets

An analysis of the financial impacts of higher energy prices can be divided into two parts: the effects on individual firms whose securities comprise the financial markets, and the macroeconomic impact on inflation and interest rates. Rising energy costs and greater volatility in energy prices can have a negative effect on both individual firms and the broader financial environment, generally producing lower asset prices and higher interest rates. The financial market impact to date of rising energy prices has been limited to firms with high sensitivity to energy costs and to those with significant exposure to the California crisis. The second broad effect of rising energy costs is an increase both in measured inflation

and in expectations for future inflation. Both factors have considerable impact on interest rates and, therefore, on the borrowing costs for businesses and consumers throughout the economy.

Inflation Expectations and Interest Rates

Measurable inflation, for both producers and consumers, is a primary concern of the Federal Reserve in conducting monetary policy. Energy costs represent roughly 16 percent of the producer price index for finished goods and 8 percent of the consumer price index. This means that sharply rising energy costs can have a substantial impact on the Federal Reserve's decision-making process. Additional impacts will come from the market's anticipating Federal Reserve actions and pushing short-term interest rates higher than they otherwise would have been. Higher short-term interest rates raise the nominal cost of borrowing for firms and individuals and can slow economic growth.

Rising energy prices can also raise the inflation expectations of lenders, which can result in higher interest rates for borrowing at longer maturities. Rising long-term interest rates can reduce long-term investment, limiting future economic growth and productivity gains. Such an outcome would carry negative consequences for growth-sensitive financial sectors, such as equity and high-yield debt markets.

More broadly, declining credit fundamentals for certain business sectors could raise borrowing costs for firms not directly affected by higher energy prices. For example, commercial paper rates for all lower-rated borrowers have been affected by the credit problems of the California utilities, and liquidity in the market has fallen. As a result, firms may need to seek other sources of financing, such as bank loans (if obtainable) or asset-backed loans, that can be more costly than traditional commercial paper issuance.

Global Financial Markets

The upward pressure on interest rates that may result from higher U.S. energy costs also affects markets beyond our borders. U.S. monetary policy and related movements in short-term interest rates can have a significant impact on other countries. While the effect varies from region to region, many emerging market economies, particularly in Latin America, are vulnerable to upward moves in U.S. interest rates.

Higher nominal interest rates in the developed countries tend to reduce the amount of capital flowing to emerging markets. To the extent that this reduces investment, economic activity may be further reduced. In addition, borrowing in dollars is a significant source of funding for sovereign and private-sector entities worldwide, particularly in the emerging markets. Rising U.S. interest rates will increase the interest expenses for these borrowers, diverting funds from more productive uses and reducing overall credit quality.

The global market for energy is highly fragmented and region-specific, with the exception of oil. Nevertheless, certain nations and regions are net importers of energy and are highly sensitive to changing prices. Japan, a major importer of oil and natural gas, is particularly vulnerable. Europe is a net importer of energy, with certain exceptions, while emerging market nations vary widely in their dependence on foreign energy sources.

At the macroeconomic level, rising energy prices will increase the current account deficit of energy-importing nations. Since current account deficits must be financed, these nations will most likely need to pay higher interest rates to attract the necessary capital. As noted, this will tend to reduce domestic investment and lower long-term growth. In some countries, such as the United States or Japan, changes in interest rates and growth expectations can have substantial global impact.

Central banks and monetary authorities vary in the degree to which they focus on inflation in setting monetary policy, making some countries more or less likely than others to raise interest rates in an environment of rising energy prices.

Although Japan maintains a current account surplus due to manufacturing exports, its role as an international creditor could diminish. This may have additional impacts on the global financial markets, since Japanese financial institutions are generally suppliers of global credit.

The impact of rising energy costs on the dollar is likely to be mixed. While slower U.S. growth generally reduces demand for dollars, rising oil prices are likely to increase demand, since oil contracts are usually denominated in dollars.

Summary of Recommendations

★ The NEPD Group recommends that the President direct the Secretary of Energy to explore potential opportunities to develop educational programs related to energy development and use. This should include possible legislation to create public education awareness programs about energy. Such programs should be long-term in nature, should be funded and managed by the respective energy industries, and should include information on energy's compatibility with a clean environment.

★ The NEPD Group recommends that the President take steps to mitigate impacts of high energy costs on low-income consumers. These steps would include:

- Strengthening the Low Income Home Energy Assistance Program by making $1.7 billion available annually. This is an increase of $300 million over the regular FY 2001 appropriation.
- Directing the Secretaries of Interior and Health and Human Services to propose legislation to bolster LIHEAP funding by using a portion of oil and gas royalty payments.
- Redirecting royalties above a set trigger price to LIHEAP, whenever crude oil and natural gas prices exceed that trigger price, as determined by the responsible agencies.

★ The NEPD Group recommends that the President increase funding for the Weatherization Assistance Program by $1.2 billion over ten years. This will roughly double the spending during that period on weatherization. Consistent with that commitment, the FY 2002 Budget includes a $120 million increase over 2001. The Department of Energy will have the option of using a portion of those funds to test improved implementation approaches for the weatherization program.

★ The NEPD Group recommends that the President support legislation to allow funds dedicated for the Weatherization and State Energy Programs to be transferred to LIHEAP if the Department of Energy deems it appropriate.

★ The NEPD Group recommends the President recognize unique regional energy concerns by working with the National Governors Association and regional governor associations to determine how to better serve the needs of diverse areas of the country.

★ The NEPD Group recommends the President direct FEMA to prepare for potential energy emergencies.

- -FEMA should work with states' Offices of Emergency Management as they expand existing emergency operations plans to identify potential problems and address consequences of the power shortages. FEMA should use its current Regional Incident Reporting System to identify any situations that might demand immediate attention.
- Using the structure of the already existing Federal Response Plan, FEMA should conduct Regional Interagency Steering Committee (RISC) meetings for states affected by the energy shortfalls. The RISC is a FEMA-led interagency committee comprised of agencies and departments that support the Federal Response Plan. Either an upcoming, scheduled RISC meeting or a special-focus RISC meeting can be held to identify the short-term energy outlook, as well as any expected consequences, in each of the states during the peak summer season.

Protecting America's Environment

Sustaining the Nation's Health and Environment

Over the last three decades, American ingenuity has led to a reduction in adverse environmental and public health impacts from energy development and use. Americans demand a reliable energy supply and a clean environment, and we can achieve both. Spurred by strong environmental concerns, competitive forces, and environmental regulations, businesses have developed innovative technologies and pollution-prevention techniques to protect the environment. However, more can be done.

As our energy needs continue to grow and our production and distribution system is strained to capacity, it is clear that the lack of a comprehensive energy policy has environmental costs. For example, to prevent blackouts, California officials must tolerate a large short-term increase in smog-forming nitrogen oxides emissions. In Los Angeles, older, dirtier power plants have had to run longer than expected. California is also rushing to use mid-sized "peaker power plants" and diesel-fired emergency backup generators to keep the lights on.

The short-term cost in increased pollutant emissions of these emergency measures has been stark. Preliminary figures from California's South Coast Air Quality Management District indicate emissions have doubled in the first three months of the year compared with last year. In addition to nitrogen oxides emissions, diesel-fired backup generators also emit toxic soot. But with many days of blackouts predicted in California this summer, these generators will most likely run for much longer than expected, and could greatly increase emissions.

In the longer term, penalties and technological improvements should offset the impact of these increased emissions. However, California's experience demonstrates the environmental costs of not building an adequate supply of clean energy.

Government's Role

The federal government has a unique role in facilitating energy development while simultaneously protecting the environment and conserving our country's natural resource legacy. Energy development initiatives will be successful only if they adequately address their impacts on natural resource values.

Federal, state, tribal, and local governments have the responsibility of protecting unique natural resources and environmental values. In fact, some environmental protections we enjoy today are often taken for granted. For example, lead levels in ambient air today are 98 percent lower than they were in 1970, largely because government regulations required that lead be removed from gasoline. The reduced number of children with IQs below 70 is attributed to reducing lead in our environment.

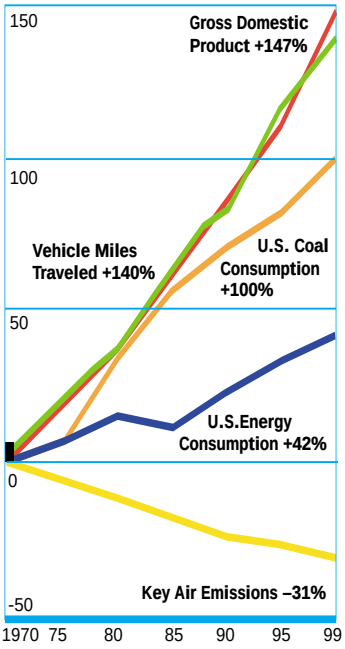
As U.S. energy needs grow, additional innovations will be necessary to continue improving environmental conditions and to meet new environmental challenges. As we improve the energy production and distribution system, all levels of government must ensure that regulatory systems protecting public health and the environment are rigorous and efficient, and encourage innovation and improvement.



Roughly 30 percent of our nation's electricity supply is now generated by nuclear, hydropower, and renewable sources, all of which have few air emissions.

Figure 3-1
Cleaner Air: Energy Consumption Has Risen While Emissions Have Declined

(Percent Change Since 1970)



Despite a marked increase in U.S. energy consumption, a combination of environmental regulations and technologies has decreased aggregate emissions of key air emissions: SO_2, NOx, mercury, CO, and volatile organic compounds.

Sources: U.S. Department of Energy, Energy Information Administration, and U.S. Environmental Protection Agency.

Air Quality

Regulatory Programs

Advances in technology and environmental regulations have decreased aggregate emissions of key air pollutants over the last three decades, despite a marked increase in energy consumption (Figure 3-1). Roughly 30 percent of our nation's electricity supply is now generated by nuclear, hydropower, and renewable sources, all of which have few air emissions.

Nonetheless, fossil fuel-fired power plants, other industrial sources, and vehicles remain significant sources of air pollution (Figure 3-2). These emissions can be associated with significant health problems, including respiratory and cardiopulmonary disease, cancer, and birth defects. In addition, they can be harmful to forests, water bodies, and fish, and can decrease visibility in scenic areas.

Environmental Protection Agency's (EPA) Acid Rain Program, enacted as part of the 1990 Clean Air Act Amendments, is the only program directed primarily at reducing air emissions from electric utilities.

Using flexible market-based incentives instead of technology-forcing standards, the program has reduced sulfur dioxide (SO_2) emissions from utilities faster than required by law for a fraction of the initial cost estimates. By 2010, EPA expects the program will reduce annual SO_2 emissions by 10 million tons from 1980 levels, thus avoiding significant health problems and the costs associated with those levels.

Federal and state regulatory programs also limit air pollution directly by restricting emissions from cars and trucks, and indirectly by setting criteria for the fuel for these vehicles. An individual car meeting 2004 federal requirements will emit 95 percent less carbon monoxide (CO), 94 percent fewer nitrogen oxides (NOx), and 98 percent fewer hydrocarbons than an average car did before laws limiting such vehicle pollution. Although individual cars and trucks are far cleaner today than they were in 1970, total emissions from the fleet of highway vehicles have remained relatively constant, because Americans drive twice as many miles today (2.5 trillion miles a year) as they did in 1970 (1.1 trillion miles a year).

Despite these and other achievements, further air quality improvements can be sought, as well as ways to address new problems identified by recent scientific findings. EPA has recently adopted new, more stringent standards to further reduce ozone and particulate matter. To meet public health and environmental challenges, power plants, industrial sources, and vehicles will need to produce fewer potentially harmful emissions.

Recommendation:

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to propose multi-pollutant legislation. The NEPD Group recommends that the President direct the EPA Administrator to work with Congress to propose legislation that would establish a flexible, market-based program to significantly reduce and cap emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power generators. Such a program (with appropriate measures to address local concerns) would provide significant public health benefits even as we increase electricity supplies.

- Establish mandatory reduction targets for emissions of three main pollutants: sulfur dioxide, nitrogen oxides, and mercury.
- Phase in reductions over a reasonable period of time, similar to the successful acid rain reduction program established by the 1990 amendments to the Clean Air Act.
- Provide regulatory certainty to allow utilities to make modifications to their plants without fear of new litigation.
- Provide market-based incentives, such as emissions-trading credits to help achieve the required reductions.

Cleaner, More Efficient Technologies

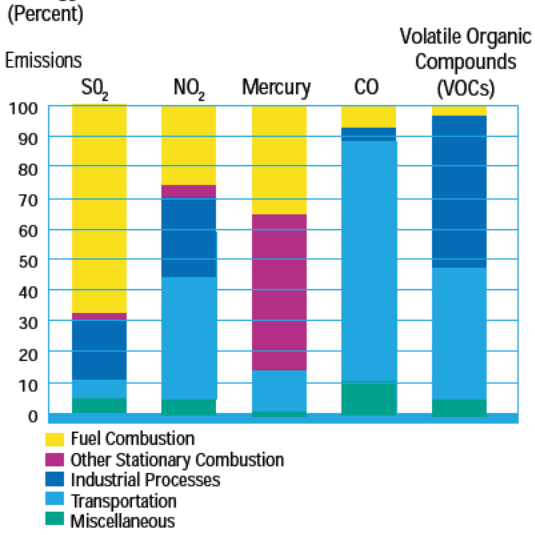
Emission control technologies and emission prevention not only decrease pollution but can also contribute to economic prosperity. Innovative emission control and prevention technology and increasingly efficient energy systems have developed at a brisk pace, increasing our ability to provide cleaner, cheaper energy. Besides reducing pollution, environmental technologies account for about $21.3 billion in U.S. exports, and support approximately 136,000 U.S. jobs.

The need to reduce emissions from cars and trucks has contributed to technological innovations that have transformed the domestic and global automotive industries. U.S. vehicle emission standards were the primary driving force for the original development of innovative technologies, many of which have become standard design features of today's high-tech vehicles: sophisticated three-way catalysts, on-board computers, oxygen sensors, and fuel-injection systems for cars and advanced fuel systems for trucks. Technologies such as these have allowed today's vehicles to be much cleaner, more efficient, higher performing, more reliable, and more durable than their counterparts of the 1960s and 1970s. Manufacturers are now working on developing state-of-the-art pollution control technology to further reduce emissions from motor vehicles. For optimal performance, this technology requires low-sulfur fuel that, consistent with applicable law, will be required in 2004 for gasoline and 2006 for diesel fuel. Some vehicles use alternative fuels (*e.g.,* natural gas, propane, ethanol, and electricity); others operate with a hybrid gasoline and electrical motor; and others are using fuel cells.

Cleaner Electricity

The source of energy used for power generation significantly affects the amount of air emissions. Clean energy can be generated from nuclear plants, hydropower facilities, wind farms, and solar energy systems with negligible (if any) air emissions. These sources today make up about 30 percent of our electricity supply. Solar and wind energy systems will continue to improve with advances in short-term weather and climate forecasting. Improved forecasting can also maximize hydropower efficiency.

Figure 3-2
Sources of Pollutants from Energy Generation and Use
(Percent)



Technology significantly reduces pollution from coal-fired power plants, which generate more electricity in the United States than any other source. For example, scrubbers can remove 95 percent of the SO_2 emissions from a coal-fired power plant. With the innovative, market-based SO_2 reduction requirements of the Clean Air Act Amendments of 1990, the estimated cost of using a scrubber on a coal-fired power plant to remove one ton of SO_2 has dropped approximately 40 percent in four years, from $474/ton in a 1993 estimate to $282/ton in a 1997 estimate, and continues to decline. Other existing control technologies for coal-fired plants can reduce NOx emissions by more than 90 percent.

A recently permitted state-of-the-art coal-fired unit, for example, at a Kansas City Power & Light facility, has 88 percent lower NOx, 99 percent lower particulate matter, and 92 percent lower SO_2 emissions than would an uncontrolled facility.

Recent research by the Department of Energy (DOE), EPA, and private companies suggests that existing technologies can also significantly reduce mercury emissions.

Technologies for Reducing SO_2 Emissions

Many power plants use flue-gas desulfurization, or scrubbers, to reduce SO_2 emissions from burning coal. The most common wet scrubber, the limestone forced-oxidation (LSFO) process, removes SO_2 from the flue gas by sorption and through chemical reactions with the limestone. LSFO technologies can remove up to 98 percent of SO_2 and significant amounts of mercury. The most common dry scrubber, the lime spray-drying process, is used for plants that burn lower-sulfur coals. A lime slurry mixes with the hot flue gas in a spray dryer and reacts with SO_2. By recapturing sorbent at the bottom of the spray dryer removed in a particulate control device, dry scrubbers can remove up to 96 percent of SO_2.

Clean Coal Technologies

New clean coal technologies are showing that air pollution can be reduced, and energy efficiency increased, by using America's abundant supply of coal.

Most conventional air emission control technologies installed on coal-fired electric-generating boilers have been designed to remove a specific pollutant from the stack flue gas. Because these technologies may not be the most cost effective means of reducing multiple pollutants, several companies are developing a single-control technology to reduce multiple air pollutants to levels equivalent to those achieved by conventional controls.

For example, a First Energy plant in New Hampshire recently pilot-tested state-of-the-art technology that has cut NOx emissions by 76 percent, SO_2 by 44 percent, total particulate matter by 99.94 percent, and mercury by 81 percent. The process uses electrically charged particles instead of catalysts to oxidize the air pollutants into products that are easily removed and can be converted to gypsum, fertilizer, and concentrated acids. American Electric Power is installing a wet scrubber system that it expects will remove up to 75 percent NOx and 90 percent mercury. It injects a phosphorus mixture into the hot flue gas, causing the release of ozone. The ozone then oxidizes the mercury into ionic mercury and the NOx into N_2, both of which are water-soluble and easily removed.

Using flexible market-based incentives, EPA's Acid Rain Program has reduced sulfur dioxide (SO_2) emissions from utilities faster than required by law for a fraction of the initial cost estimates.



Technologies for Improved Efficiencies

Two-thirds of the energy used in a conventional coal-fired power plant is wasted in the production of electricity. These losses can be minimized through a number of innovations, including installing high efficiency steam turbines, reducing steam leaks, and using software to optimize combustion efficiency. New coal-burning power plants can achieve efficiencies of over 40 percent using existing technology, and companies are developing even more efficient technologies. Wasted energy can also be recycled for use in industrial processes or for heating buildings.

A family of technologies known as combined heat and power (CHP) can achieve efficiencies of 80 percent or more. In addition to environmental benefits, CHP projects offer efficiency and cost savings in a variety of settings, including industrial boilers, energy systems, and small, building-scale applications. At industrial facilities alone, there is potential for an additional 124,000 megawatts (MW) of efficient power from gas-fired CHP, which could result in annual emission reductions of 614,000 tons of NOx emissions and 44 million metric tons of carbon equivalent. CHP is also one of a group of clean, highly reliable distributed energy technologies that reduce the amount of electricity lost in transmission while eliminating the need to construct expensive power lines to transmit power from large central power plants.

The U.S. Department of Energy, through its Clean Coal Technology Program, is working with utilities and scientists to develop even cleaner, more efficient electricity-generating systems using coal. One of the most promising new approaches to using coal for clean production of electricity is integrated gasification combined-cycle (IGCC) technology. IGCC power plants convert coal to a gaseous fuel, from which most

Clean Coal Technologies Up Close

The Wabash River Coal Gasification Project in Terre Haute, Indiana, is one of the cleanest, most efficient coal-burning facilities in the country. Partly funded by the Department of Energy (DOE) as part of its Clean Coal Technology Program, the 262-MW coal gasification facility is owned and operated by PSI Energy and Global Energy, Inc. Instead of being directly burned, the coal is gasified and then combusted in a combined-cycle gas turbine. This allows the coal to burn more efficiently—which means it gets more energy than a traditional plant out of the same amount of coal. The Wabash River Facility is over 20 percent more efficient than a typical coal-fired power plant.

The gasification process also allows many of the impurities in the coal to be removed before it is combusted to generate electricity. At the Wabash River project, over 99 percent of the sulfur is removed from the coal and marketed to industrial users of sulfur. Slag is also removed and is marketed to the construction industry. The plant's design allows it to burn other fuels, such as petroleum coke.

DOE is currently working with Global Energy and other industry partners to see if the plant could also be used to co-produce chemical feedstocks and transportation fuels. Additionally, DOE and its partners are studying lessons learned from the project to design a less expensive, more efficient coal gasification facility that would be ready for commercial deployment by 2005.

of the impurities are removed prior to combustion, and then use the gaseous fuel in a combustion turbine to produce electricity. Waste heat from the turbine is used to generate steam and drive a steam turbine, to produce more electricity.

Coal gasification plants offer the flexibility to burn other fuels, such as petroleum coke, and to make other products in addition to electricity, such as chemical feedstocks and transportation fuels. Hydrogen, which is produced directly in the coal gasifier, can be used in fuel cell-equipped vehicles. Methane, hydrogen, and other gasified coal products can be recombined into more traditional fuels, such as methanol, gasoline, or diesel fuel. Because these fuels would contain essentially no sulfur, they would easily meet EPA's sulfur standards for transportation fuels, and they would be usable in fuel cell-equipped vehicles designed for these fuels.

Two plants demonstrating coal gasification technology have already been built in the United States and have achieved over 98 percent SO_2 reduction, 90 percent NOx reduction, particulate emissions below detectable levels, and approximately 38 percent efficiency. EPA believes that lessons learned will enable the next plant of this design to achieve 42 percent efficiency, and the research goal is to achieve 60 percent efficiency for plants introduced after 2015.

A modern gas-fired power plant has virtually no SO_2 or mercury emissions and emits 97 percent less NOx and 50 percent less carbon dioxide (CO_2) than a traditional coal-fired plant. Natural gas as a source of electricity generation is on the rise, in part because it can help generators meet increasingly stringent clean air requirements.

Conservation and Environmental Protection

Conserving energy minimizes adverse environmental effects. Government partnerships with businesses and consumers are improving the energy efficiency of homes, office buildings, transportation sources, and industrial sites throughout the country. EPA's voluntary conservation and energy efficiency programs include Energy Star products labeling; Energy Star Residential programs for both new homes and home improvement; Energy Star Buildings, principally for commercial buildings; and new Energy Star for Industry, which focuses on manufacturers. In 2000, business participation in EPA's voluntary energy efficiency

programs reduced NOx emissions by more than 160,000 tons.

Through EPA's and the Department of Transportation's Commuter Choice Leadership Initiative, private-public employers are offering employees a variety of commuting options, which encourage commuting patterns that save fuel and energy while reducing emissions. For example, a 10 percent reduction in the rate of growth in vehicle miles traveled can result in annual savings of 38 million barrels of gasoline (82 million barrels of oil) by 2005, and can remove 45,000 metric tons of NOx, 37,000 metric tons of hydrocarbons, and 4.8 million metric tons of carbon-equivalent emissions.

Energy efficiency and conservation in the home are also important factors. Examples include EPA's home improvement program, which involves efficient appliances, duct work to prevent air conditioners from leaking, efficient windows, programmable thermostats, and efficient residential lighting.

Federal and state regulators are working with businesses and communities to mitigate adverse environmental impacts by requiring developers and operators to choose more environmentally friendly sites, infrastructure routes, and operational criteria; fostering the use of technologies that both protect the environment and still meet energy production goals; and requiring reclamation and mitigation of any environmental damage.



Water Quality

Oil, gas, and coal extraction processes can degrade water quality through their discharges. Energy generation and use can also degrade water quality by directly discharging pollutants into water bodies; changing the temperature, timing, and flow characteristics of water bodies; and emitting pollutants into the air that are ultimately deposited in water. Leaking storage tanks and pipelines release petroleum and fuel additives that can contaminate surface water and ground water, including drinking-water supplies.

Federal and state regulators are working with businesses and communities to mitigate these adverse impacts by requiring developers and operators to choose more environmentally friendly sites, infrastructure routes, and operational criteria; fostering the use of technologies that both protect the environment and meet energy production goals; and requiring reclamation and mitigation of any environmental damage. For example, as a result of an analysis under the National Environmental Policy Act of the impacts of a new power plant in California, the company building the plant agreed to change the design to use a dry cooling method. This change reduced ground-water consumption by 95 percent and eliminated both cooling tower "blowdown" water and particulate emissions, while still achieving the desired energy production. Adverse impacts to aquatic life from cooling-water intakes, thermal discharges, and hydropower intakes can be minimized with proper design and environmental controls. A cooperative government, industry, and community-based approach during project siting and design will help ensure full consideration of the effects upon fish and aquatic resources.

Programs to reduce air pollution also help clean up water bodies. For example, reducing electric utilities' air emissions of NOx and SO_2 and vehicles' NOx emissions reduces eutrophication and acid deposition in estuaries, both of which can harm fish populations and threaten commercial and recreational yields. For example, roughly 25 percent of nitrogen (which contributes to

eutrophication) entering Chesapeake Bay is from air emissions. And by significantly reducing SO_2 air emissions, the Acid Rain Program has helped reduce the acidification of water bodies.

Airborne mercury emitted by coal-fired power plants has been deposited into thousands of water bodies, and humans can be exposed to toxic methyl mercury when they eat fish from these waters. The Bush Administration will propose legislation adding mercury to the list of pollutant emissions from power plants that will be subject to mandatory limits.

Fish, Wildlife, and Their Habitat

Ecosystems provide food, shelter, and critical breeding and spawning grounds for fish and wildlife, and support commercial and recreational fishing, tourism, and other activities that contribute billions of dollars to the U.S. economy every year. Oil and gas exploration and production, hydropower dams, power plants, pipelines, and other energy-related projects can potentially affect fish, wildlife, and habitat. However, technological advances, a strong commitment to environmental protection, and the use of appropriate regulatory tools can enable proper energy development to go forward in an environmentally sensitive manner. It is important to recognize and to continue the progress in this area.

When energy development is proposed, the federal government has the dual responsibilities of facilitating such energy development *and* conserving our natural resource legacy.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress to create the "Royalties Conservation Fund."

- This fund will earmark potentially billions of dollars in royalties from new oil and gas prodution in ANWR to fund land conservation efforts.
- This fund will also be used to eliminate the maintenance and improvements backlog on federal lands.



Technological advances and a strong commitment to environmental protection are enabling the healthy coexistence of our nation's diverse ecosystems with the development of energy resources.

Special efforts are often necessary to ensure that proposed energy projects do not diminish the vitality of these unique resources. Working together, the public, businesses, and federal, state, tribal, and local governments can ensure that environmental impacts are carefully evaluated when considering energy exploration and production activities. For example, such precautions have been important for the exploration and production that is already allowed today in 42 National Wildlife Refuges.

Hydropower Generation

Hydropower, although a clean energy source, does present environmental challenges. Unless properly designed and operated, hydropower dams can injure or kill fish, such as salmon, by blocking their passage to upstream spawning pools. Innovations in fish ladders, screens, and hatcheries are helping to mitigate these adverse impacts. Ongoing dam relicensing efforts are resulting in community involvement and the industry's application of the latest technologies to ensure the maintenance of downstream flows and the upstream passage of fish. These efforts also have been successful in identifying and removing older, nonfunctioning dams and other impediments to fish movements.



Ecosystems provide food, shelter, and critical breeding and spawning grounds for fish and wildlife, and support commercial and recreational fishing, tourism, enhance our quality of life,and other activities that contribute billions of dollars to the U.S. economy every year.



Some natural resource areas are to be protected from any exploration. In other areas, energy development can proceed using the most advanced designs and technologies to ensure that proposed energy projects do not diminish the vitality and diversity of these unique resources.

An example of such successful collaboration involves the Wanapum Dam on the Columbia River. In coordination with the National Marine Fisheries Service, the Grant County Public Utility District No. 2 installed spillway deflectors that effectively reduced concentrations of total dissolved gas that can harm fish and other aquatic life. Furthermore, through the unique collaboration on this project, the cost for the spillway deflectors was a fraction of that for deflectors installed at other hydropower projects.

Coal, Oil, and Gas Exploration and Production

Certain exploration and production activities can pose environmental impacts to wildlife habitat, unless conducted in a way that protects the environment. In sensitive areas, these effects can often be avoided or minimized by timing exploration and operation activities in light of migration, nesting, and other critical time periods for wildlife. In addition, new technologies designed to lessen these and other impacts can be used, such as double-walled pipes to reduce the risk of oil spills.

Surface impacts from coal mining and oil exploration can temporarily damage habitats during the operation phases until reclamation is complete. To mitigate impacts during mining, for example, stormwater runoff and discharge into undisturbed environments are controlled. After mining is complete, reclamation efforts required by the Surface Mining Control and Reclamation Act restore viable habitats through careful reconstruction of physical and botanical resources. For instance, in the Powder River Basin, as part of reclamation, coal companies strategically place large boulders and other rock material to create wildlife cover and denning habitat. Restoration of wildlife habitat on these reclaimed areas has been quite successful.

In Alaska's Arctic—home to such animals as polar bears, musk oxen, caribou, wolves, and arctic fox—the bitterly cold winters have proven to be beneficial for environmentally responsible energy development. For example, when the North Slope is frozen and snow-covered, seismic trains can travel across it to gather geophysical information. Furthermore, companies have adopted innovative techniques to reduce the possible impacts of exploration and development. In Alaska's National Petroleum Reserve, the "footprint" from most exploratory wells on federal lands is short-lived and has minimal impact due to the use of ice roads and ice pads that melt with the spring thaw. Advances in extended-reach drilling technologies have also served to minimize environmental effects during energy production activities.

A lengthy 1999 Department of Energy study examined the environmental benefits of new exploration and production technologies and concluded that "improvements over the past 40 years have dramatically reduced industry's footprint on the fragile tundra, have minimized waste produced, and have protected the land for resident and migrating wildlife." The same study concluded that "it is important to tell this remarkable story of environmental progress in E&P [exploration and production] technology. Greater awareness of the industry's achievements in environmental protection will provide the context for effective policy, and for informed decision-making by both the private and public sectors."

Waste Management

Vigilant management and careful disposal of waste from energy extraction and production can prevent the contamination of our air, land, and water. Federal and state authorities are working to ensure that energy projects maintain sound programs to safely handle wastes from mining, drilling, generation and transmission.

Nuclear power plants present waste management challenges unique among energy-generating technologies. They generate spent fuel, as well as other radioactive waste, which must be isolated from ecosystems and human contact for long periods of time. Currently, spent fuel is stored at reactor sites in a number of states, although capacity is limited. Newer technologies have been developed to reduce the volume and

increase the manageability of spent fuel, but such spent fuel will still require safe handling and long-term isolation.

While the federal government has the responsibility to address such high-level wastes, states have the responsibility to address low-level wastes from nuclear plants, such as clothing and equipment. Disposal options for this type of radioactive waste are limited, because siting these facilities has been controversial. In fact, there are only three disposal facilities active in the United States.

Accidental Releases

Since the passage of the Oil Pollution Act in 1990, which, among other things, required double-hulled vessels and improved industry readiness, oil spilled in coastal zone waters has decreased from almost 8 million gallons in 1990 to just over 1 million gallons in 1999. Most energy production facilities implement comprehensive risk-management plans, which reduce the potential for accidents and help local officials prepare for accidents that may arise.

In contrast, inland oil spills do not appear to be decreasing at the same rate as coastal spills. The federal government receives many more inland oil spill notifications (9,000 notifications a year in the early 1990s versus 10,000 to 12,000 a year in the late 1990s), and many very large inland oil spills occur each year (over 100,000 gallons). The continued problem with inland oil spills may be due to aging pipelines, storage tanks, and other infrastructure components.

Since the advent of commercial nuclear power generation, there have been no radiation-related injuries or deaths associated with the operation of a commercial nuclear power plant in the United States. The most significant incident from a nuclear plant in the United States, at Three Mile Island in 1979, prompted improved safety regulation of nuclear plants. New nuclear reactor designs promise even higher safety levels than the reactors currently operating in this country.

Radiation exposure from nuclear facilities is extremely rare. In fact, roughly 82 percent of human exposure to radiation comes from natural sources: radon gas; the human body, which contains radioactive elements; outer space; and rocks and soil. Radon accounts for about 55 percent of our exposure to natural sources of radiation; radioactive elements in our own bodies account for 11 percent; rocks and soil account for 11 percent; and outer space, including the sun, accounts for 8 percent. The remaining 18 percent of average human radiation exposure comes from man-made sources, primarily medical and dental X-rays and consumer products.

The safety of U.S. nuclear energy plants has improved sharply in recent years. A safe nuclear energy plant is one that runs well, experiences few unplanned outages, and has a well-disciplined work force that follows procedures and avoids accidents. The safety of a U.S. nuclear energy plant is typically gauged by monitoring indicators of its performance in these areas: unplanned automatic reactor shutdowns, the annual percentage of possible power generated, and the industrial safety accident rate for plant workers.

In 2000, for the fourth year in a row, the number of unscheduled reactor shutdowns was zero. The industry generated 91.1 percent of its potential maximum output, breaking its 1999 record of 88.7 percent, far better than the typical 80 percent number of ten years ago.

Today, U.S. nuclear plants are more efficient and safer than ever. In the increasingly deregulated marketplace, competition has forced improvements in plant operations that have benefited safety performance as much as economic performance.

Climate Change

Energy-related activities are the primary sources of U.S. man-made greenhouse gas emissions, representing about 85 percent of the U.S. man-made total carbon-equivalent emissions in 1998.

Scientists continue to learn more about global climate change, its causes, potential impacts, and possible solutions.

The United States recognizes the seriousness of this global issue as scientists attempt to learn more about climate change. The United States is making progress in reducing emissions of greenhouse gases. Recent data show that the rate of growth in U.S. greenhouse gas emissions has begun to decline, even as the U.S. economy has been growing at an unprecedented rate. For example, historically U.S. CO_2 emissions have grown at roughly half the rate of GDP. In recent years, however, very robust growth in the nation's GDP has been accompanied by a slowdown in the growth of greenhouse gas emissions. In both 1998 and 1999, U.S. GDP grew by more than 4 percent a year, while CO_2 emissions grew by less than 1.5 percent a year. In addition, the carbon intensity of the U.S. economy—the amount of CO_2 emitted per unit of GDP—declined by 15 percent during the 1990s.

The United States has reduced greenhouse gas emissions by promoting energy efficiency and the broader use of renewable energy through a wide range of public-private partnership programs. These programs save energy, cut energy bills, enhance economic growth, and reduce emissions of conventional air pollutants as well as greenhouse gases.

The U.S. government, businesses, and nongovernmental organizations are sequestering carbon, at home and abroad. For example, working with the U.S. Fish and Wildlife Service Research, Illinova Generating Company has voluntarily committed to reforesting 100,000 acres of bottomland hardwood forests on National Wildlife Refuges in the Lower Mississippi River Valley. It is projected that this project will sequester approximately 13.5 million tons of carbon, improve fish and wildlife populations by restoring the natural forest wetland habitats, and enhance the Gulf of Mexico's near-shore aquatic environment by restoring natural forested wetland filters to the Mississippi River floodplain.

Industry and the federal government are researching various new technologies that will reduce greenhouse gas emissions or sequester those emissions, in geologic formations, oceans, and elsewhere.



Forests can absorb carbon dioxide, which accounts for the largest share of greenhouse gas emissions. Working with the U.S. Fish and Wildlife Service Research, Illinova Generating Company has voluntarily committed to reforesting 100,000 acres of bottomland hardwood forests on National Wildlife Refuges in the Lower Mississippi River Valley.

Regulatory Structure

The United States has adopted many regulatory protections to limit the environmental damage and public health consequences of the exploration, extraction, production, and use of energy. Most environmental controls are implemented through state or federal permitting or review systems, which often require time for agency review and public participation. Facilities may need several different permits or reviews from different agencies, and they may also need to meet local licensing or zoning laws. Businesses have an interest in moving expeditiously to respond to consumers' needs. The public also has an interest in participating in the system to ensure that appropriate health and environmental precautions will be taken.

Regulatory requirements are not static. New scientific information and new control technologies result in new regulations and modifications to existing regulations over time. However, some level of certainty in the regulatory environment is important for all parties. Businesses can plan more effectively in such an environment, and regulators can focus on ensuring that the desired outcomes are in fact achieved consistently. For example, studies have shown that if electricity generators knew today what their emission requirements for several emissions would be for a defined time period, they would most likely control emissions more cost effectively and sooner than if their emission requirements were decided upon one gas at a time.

Traditional permit and regulatory programs may not always be the most effective and efficient way to protect the environment. Increasingly, regulatory programs are considering approaches that include market-based incentives. These types of incentives offer advantages over traditional forms of regulation because they set high performance standards and then allow market forces to determine the most effective way to meet them. While not appropriate for every situation, market-based incentives can control pollution at a lower cost to society than traditional regulation, stimulate technological improvements, and be structured to achieve larger reductions in pollution than would result from traditional regulations.

A good example of a U.S. market-based program is the Acid Rain Program, which has reduced SO_2 air emissions from utilities at a fraction of the initial cost estimates. Other emerging market-based environmental protection mechanisms include effluent trading, wetland mitigation banks, tradable development rights, easement purchases, off-site mitigation, and leasing or purchasing of water rights. These programs can reduce mitigation or pollution control costs, increase business flexibility, and provide transparency and environmental protection for the public.



The environmental review process can also be made more open, understandable, predictable, and coordinated among federal agencies and with state and local agencies. It can be improved by providing greater information to clarify expectations for energy developers, facilitating concurrent reviews by federal agencies by standardizing certain information needs, sharing information received by project applicants, and seeking opportunities to integrate required environmental processes and reviews.

Recommendation:

★ The NEPD Group recommends that the President issue an Executive Order to rationalize permitting for energy production in an environmentally sound manner by directing federal agencies to expedite permits and other federal actions necessary for energy-related project approvals on a national basis. This order would establish an interagency task force chaired by the Council on Environmental Quality to ensure that federal agencies responsible for permitting energy-related facilities are coordinating their efforts. The task force will ensure that federal agencies set up appropriate mechanisms to coordinate federal, state, tribal, and local permitting activity in particular regions where increased activity is expected.

Summary of Recommendations

Protecting America's Environment: Sustaining the Nation's Health and Environment

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to propose multi-pollutant legislation. The NEPD Group recommends that the President direct the EPA Administrator to work with Congress to propose legislation that would establish a flexible, market-based program to significantly reduce and cap emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power generators. Such a program (with appropriate measures to address local concerns) would provide significant public health benefits even as we increase electricity supplies.

- Establish mandatory reduction targets for emissions of three main pollutants: sulfur dioxide, nitrogen oxides, and mercury.
- Phase in reductions over a reasonable period of time, similar to the successful acid rain reduction program established by the 1990 amendments to the Clean Air Act.
- Provide regulatory certainty to allow utilities to make modifications to their plants without fear of new litigation.
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★ The NEPD Group recommends the President direct the Secretary of the Interior to work with Congress to create the "Royalties Conservation Fund."

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Using Energy Wisely

Increasing Energy Conservation and Efficiency

The Department of Energy has installed two low-sulfur light bulbs as a test at its Forrestal Building headquarters in Washington, D.C. The two golf ball-sized bulbs, like those on the opposite page, are at each end of a 240-foot, 10-inch-wide reflective plastic "light pipe."
U.S. Departmentof Energy



U S Departmentof Energy

Energy efficiency is the ability to use less energy to produce the same amount of lighting, heating, transportation, and other energy services. For a family or business, conserving energy means lower energy bills. For the country as a whole, greater energy efficiency helps us make the most of U.S. energy resources, reduces energy shortages, lowers our reliance on energy imports, mitigates the impact of high energy prices, and reduces pollution. Improvements in efficiency can be particularly effective in reducing energy demand when energy is most expensive.

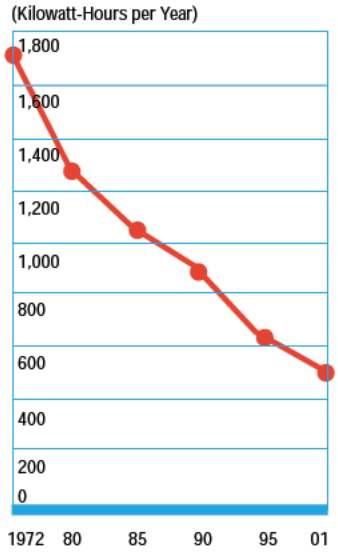
Conservation and energy efficiency are important elements of a sound energy policy. Improved energy efficiency is the result of many decisions, including those of individual consumers; manufacturers of cars and appliances; home builders; and state, federal, and local government officials. The federal government can promote energy efficiency and conservation by including the dissemination of timely and accurate information regarding the energy use of consumers' purchases, setting standards for more energy efficient products, and encouraging industry to develop more efficient products. The federal government can also promote energy efficiency and conservation through programs like the Energy Star program, and search for more innovative technologies that improve efficiency and conservation through research and development.

Since 1973, the U.S. economy has grown nearly five times faster than energy use (126 percent versus 26 percent). Had Americans continued to use energy as intensively as in 1970, the U.S. would have consumed about 177 quadrillion Btus of energy last year, compared to about 99 quadrillion Btus actually consumed.

British Thermal Unit (Btu)
A British thermal unit is the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit at sea level. Put another way, it is approximately the same amount of energy contained in a wooden match head.



Figure 4-1
New Refrigerator-Freezers are Using Less Energy
Consumption per Unit for New Shipments



Over the last thirty years, the energy efficiency of refrigerator-freezer appliances has increased by approximately 70 percent.

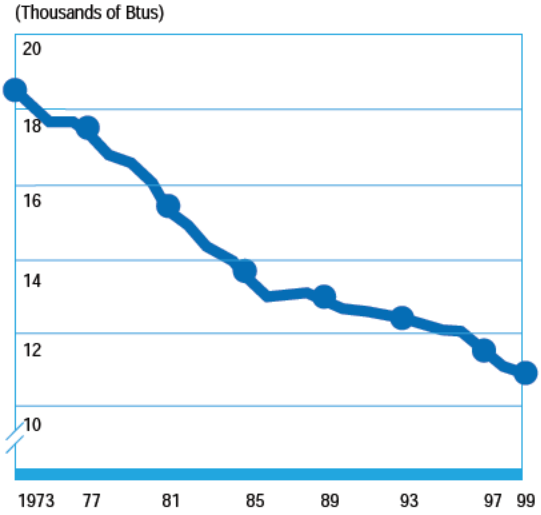
Sources: AHAM 2000 Major Home Industry Fact Book and BTS appliance standard.

Improving Efficiency through Innovative Technologies

One measure of energy efficiency is energy intensity—the amount of energy it takes to produce a dollar of gross domestic product (GDP). While about half of the long-term decline in energy intensity can be attributed to changes in the economy, especially the shift from manufacturing to services, the other half reflects improved energy efficiency. Gains in energy efficiency over the last three decades were built on a combination of technological improvements, better management practices, and learning to put these technologies and practices to their best use in automobiles, homes, offices, factories, and farms. In many areas the results have been quite impressive. New home refrigerators use about one-third of the electricity they used in 1972 (Figure 4-1). Compact fluorescent lights use about 25 percent of the electricity of the incandescent bulbs they replace. Automobiles use roughly 60 percent of the gasoline they did in 1972 per mile driven. These individual technological improvements have resulted in significant reductions in energy use (Figure 4-2).

Several new and innovative technologies offer expanded opportunities to improve our energy efficiency. For example, advanced sensors and controls enable more efficient operation of buildings and factories, and allow equipment and lights to be turned off or dimmed when not in use. Hybrid vehicles use power electronics and battery storage to get more out of every gallon of gasoline consumed, and provide the ability to double vehicle mileage. Cogeneration of electricity and heat and combined heat and power allow for the productive use of much of the waste heat from electricity production, which accounts for about two-thirds of the energy used to produce electricity.

Figure 4-2
The U.S. Economy Has Become More Energy Efficient



The amount of energy used by the United States in relation to its economic output has steadily declined since the early 1970s.

Source: U.S. Department of Energy, Energy Information Administration.

District Energy St. Paul—A Combined Heat and Power Plant

District Energy St. Paul, Inc., is a combined heat and power plant that can operate on natural gas, oil, or clean-burning coal that is mixed with wood chips. These wood wastes come from downed trees, trimmings, and branches. District Energy has been able to keep its rates stable because it is able to rely on a diverse fuel supply. District Energy serves about 75 percent of all building space in the city. Nearly 150 large buildings and 3,200 residential units use the system. It is the largest system of its kind in the nation.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of energy efficiency research and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.

Consumer Choices

The two most important factors in consumers' decisions about purchasing an energy efficient product are price and the life of the product. When energy prices are high, consumers tend to weigh energy efficiency more heavily. Unless consumers are informed about the price of energy, they may not have the incentive to select the most energy efficient product.

Consumers do not receive timely signals about rising electricity costs in order to make adjustments to their energy use and efficiency. When consumers' peak costs are averaged with off-peak costs, the higher cost of peak electricity supplies is masked. As a result, consumers may not recognize the benefits of investing in technologies that best target peak consumption.

Some energy efficiency improvements are easiest and most cost effective to undertake when first building new factories, cars, equipment, appliances, and buildings. Some energy-using equipment, like computers, are used for only a few years before being replaced. Other equipment is used from five to twenty years, such as home appliances, home electronics, and lighting systems. Some capital stock, such as buildings and boilers, can last a half a century or more.

The average car now lasts fourteen years, and newer cars have even more longevity. Vehicle efficiency improvements require significant technological changes. Development of new-car production models requires at least three to four years, which limits the rate at which new technologies can enter the market. Making fundamental changes, such as switching to the use of a fuel cell, would take even longer. Once those new vehicles are in the showroom, it then takes several more years before they constitute any sizable percentage of total vehicles.

In a typical U.S. home, appliances are responsible for about 20 percent of the energy bills. Refrigerators, freezers, clothes washers, dryers, dishwashers, and ranges and ovens are the primary energy-using appliances in most households. Taking steps to save energy while using these appliances, and replacing old inefficient appliances with modern ones can save money.



Some efficiency improvements are easiest and most cost-effective to undertake when first building new factories, cars, equipment, appliances and buildings.

The federal government established a mandatory program in the 1970s requiring that certain types of new appliances bear a label to help consumers compare the energy efficiency of various products. Under this program, all refrigerators, freezers, clothes washers, and dishwashers are sold with yellow Energy Guide labels to indicate their energy efficiency. These labels provide an estimated annual operating cost of the appliance, and also indicate the cost of operating the models with the highest annual operating cost and the lowest annual operating cost. By comparing a model's annual operating cost with the operating cost of the most efficient model, you can compare their efficiencies. This labeling program ensures that consumers have the information they need to make the right decisions when they purchase major home appliances. However, Energy Guide labels are not currently required for some products, such as kitchen ranges, microwave ovens, clothes dryers, on–demand water heaters, portable space heaters, and lights.

The federal government not only ensures consumers have information on the energy efficiency of major home appliances. It also promotes the most energy efficient products through the Energy Star program, a joint program run by the Department of Energy and the Environmental Protection



In April 2001, the Sustainable Buildings Industry Council showcased a net-zero-energy home featuring passive solar design strategies, an integrated photovoltaic system, domestic solar hot water, high-efficiency lights and appliances, and a host of sustainable, market-ready components and systems.
Sustainable Buildings Industry Council



A 48-story skyscraper at the corner of Broadway and 42nd Street in New York City has a photovoltaic skin that uses thin-film PV panels to replace traditional glass cladding material. The PV curtain wall extends from the 35th to the 48th floors on the south and east walls of the tower, making it a highly visible part of the New York City skyline.
U.S. Department of Energy, National Renewable Energy Laboratory

Agency. Energy Star is only awarded to appliances that significantly exceed minimum energy efficiency standards. The Energy Star program does not extend to all products. Energy efficiency would be further promoted if the Energy Star program were expanded to a broader range of products.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to promote greater energy efficiency.

- Expand the Energy Star program beyond office buildings to include schools, retail buildings, health care facilities, and homes.
- Extend the Energy Star labeling program to additional products, appliances, and services.
- Strengthen Department of Energy public education programs relating to energy efficiency.

Energy efficiency can also be improved by the establishment of minimum energy efficiency standards. Congress enacted legislation in 1987 and 1988 to establish minimum energy efficiency standards for many major appliances. These standards apply to manufacturers, not consumers. Appliance manufacturers must produce products that meet the minimum level of energy efficiency. These rules do not affect the marketing of products manufactured before the standards went into effect, and any products made beforehand can be sold. The new standards will stimulate energy savings that benefit the consumer, and reduce fossil fuel consumption, thus reducing air emissions.

These laws established minimum energy efficiency standards for many appliances, including refrigerators, refrigerator-freezers, freezers, room air conditioners, fluorescent lamp ballasts, and incandescent reflector lamps, clothes dryers, clothes washers, dishwashers, kitchen ranges, and ovens, pool heaters, and water heaters. The Energy Policy Act of 1992 added standards for fluorescent and incandescent reflector lamps, plumbing products, electric motors, and commercial water heaters, and heating, ventilation, and air conditioning systems. Under current law, the Department of Energy can raise the minimum energy efficiency standards for these appliances if certain criteria are met, such as cost, technological feasibility, and the impact on competition among appliance manufacturers. In addition, the Department can set energy efficiency standards for appliances not covered by these laws.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to take steps to improve the energy efficiency of appliances.

- Support appliance standards program for covered products, setting higher standards where technologically feasible and economically justified.
- Expand the scope of the appliance standard program, setting standards for additional appliances where technologically feasible and economically justified.

Energy Efficiency

Government Agencies

As the largest energy consumer in the nation, the U.S. government's cost- and energy-saving opportunity is enormous. In 1999, the government consumed nearly 1.1 percent of all U.S. energy and spent nearly $8 billion for its vehicles, operations, and its nearly 500,000 buildings.

The federal government has reduced its energy use in buildings by about 30 percent from 1990 levels, largely by installing energy efficient technologies (Figure 4-3). It has reduced its energy use for vehicles and equipment by 35 percent. Some of these improvements are attributable to the Department of Energy, whose Federal Energy Management Program helps government agencies reduce their energy and water use, manage their utility costs, and promote renewable energy.

Recommendations:

★ The NEPD Group recommends that the President direct heads of executive departments and agencies to take appropriate actions to conserve energy use at their facilities to the maximum extent consistent with the effective discharge of public responsibilities. Agencies located in regions where electricity shortages are possible should conserve especially during periods of peak demand.

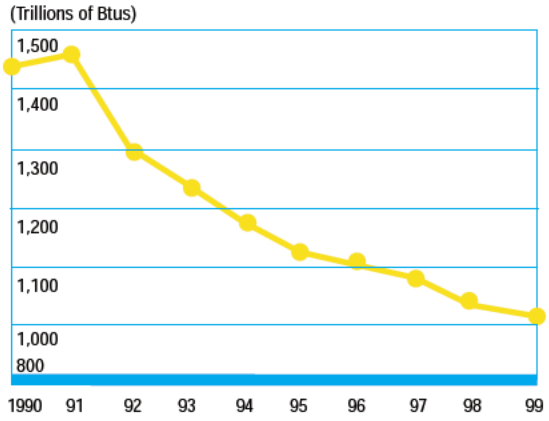
- Agencies should report to the President, through the Secretary of Energy, within 30 days of the conservation actions taken.

State and local governments have unique opportunities for energy savings in schools, transportation, state buildings, and building codes. For example, the Texas School Energy Management Program could save school districts as much as $100 million in energy costs every year by helping school districts evaluate their energy needs and resources. Similarly, Wisconsin's Energy Initiative is working with utilities to make basic changes to public buildings. By installing new lighting fixtures and taking other steps, Wisconsin estimates that it will save $60 million in state spending on energy over ten years.

Residential and Commercial Buildings

There are significant opportunities to improve the energy efficiency of buildings and homes through technologies and better practices. For existing homes, immediate options for improving efficiency include reducing air infiltration with caulking and weather stripping, installing modern thermostats, sealing ductwork, and adding insulation. These steps can reduce the 40 percent share of residential energy bills that

Figure 4-3
The U.S. Government is Reducing Its Energy Consumption



During the 1990s, energy use in federal buildings decreased by about 30 percent.

Source: U.S. Department of Energy, Energy Information Administration.



Pulte Homes

Building America—Pulte Homes

Pulte Homes Southwest Division has used technical assistance from the Department of Energy's Building America program to create what one residential expert calls "the best production house in the world," which won the 2001 National Association of Home Builders' Energy Value Award. In Tucson, Phoenix, and Las Vegas, Pulte Homes has worked with the Department of Energy to redesign the energy features of its basic models.

Using advanced insulation techniques, highly efficient equipment and windows, and right-sized heating and cooling systems, the homes look the same, but perform so well they use half the energy for heating and cooling at virtually no increase in construction costs.

The whole building/systems engineering approach used in the Building America program allows builders to add more insulation and more efficient windows while reducing the size of the heating and cooling equipment. The trade-off means no added cost to the builder, better value for the buyer, reduced electric load for the utility, and improved affordability.

go toward heating and cooling. Additional savings are possible when efficient appliances are purchased or major home renovations are undertaken. Installing a new, more efficient gas furnace can save up to 20 percent annually on natural gas. New buildings offer the greatest energy efficiency opportunities and can be designed to be both more comfortable and more efficient, cutting heating and cooling costs by close to 50 percent.

In commercial buildings, typically the quickest, most cost effective way to increase energy efficiency is to replace the lighting systems. Sensors help to avoid 24-hour operation of lights and equipment that are only used for a portion of the day. As with homes, advances in windows, heating and air conditioning systems, overall building designs, and equipment and appliances present significant energy saving opportunities.

Many families and businesses can face obstacles to realizing energy cost reductions.

Insufficient Information

Monthly energy bills generally report only total electricity or natural gas used, leaving families and businesses unsure about which energy services are most responsible for their energy use, and which investments could best help them reduce their costs. In addition, consumers may be unsure about the credibility of the energy-saving claims of individual manufacturers, salesmen, and designers. This incomplete information causes imperfections in the marketplace that hinder purchases of efficient technologies that would actually save families and businesses money.

Lack of Availability

Frequently, the most energy efficient products cost more and are not widely available, especially in smaller communities. Builders who would like to construct more efficient homes and businesses face the same problem at the wholesale level. For example, to keep costs down, builders are less likely to install top-of-the-line,

highly efficient products. The less expensive and generally less efficient products are heavily stocked and deeply discounted due to volume ordering. The decisions made about the energy efficiency of buildings and homes are not usually made by the consumer who will ultimately pay the energy bills. The incentive is for the builders to choose the material that poses the least cost to the builder, which is not necessarily the most energy efficient choice.

Lack of Automation

People often walk out of their offices and homes with the lights on and the air conditioner running. Turning off unused appliances, electronics, and lights is not always easy. Lack of automation (e.g., daylight sensors) means that conservation mostly depends on people turning off switches. Some appliances and electronics, such as stereos, video tape players, and televisions, continue to use electricity even after they are turned off.

Higher Initial Costs

Efficient products often cost more than less efficient versions, especially when they are first introduced to the market. Unless consumers can verify the resulting savings, they may be reluctant to pay the additional costs. Businesses that adopt labeling programs that spell out energy savings may be more successful in selling a more efficient, yet initially more expensive product. Higher initial costs can be particularly difficult for the purchaser or builder of a new home or office building.

Industry and Agriculture

Six industries consume three-quarters of all industrial energy: lumber and paper; chemicals; petroleum refining; primary metals; food processing; and stone, clay, and glass. Improved energy efficiency in these energy-intensive industries yields even larger improvements in overall productivity, product quality, safety, and pollution prevention. Manufacturing companies generally obtain their largest savings from improved efficiency of motors (motors account for 54 percent of electricity use in manufacturing) and from improved steam and hot-water systems. Many companies can reduce energy needs further by cogenerating their electricity and heat for steam.



High energy prices during the 1970s and early 1980s caused many farmers to find ways to reduce their energy costs, such as by switching from gasoline-powered to more fuel efficient diesel-powered engines and by adopting conservation tillage practices.

Energy use for U.S. agriculture grew during the 1960s and 1970s, peaking in 1978. High energy prices during the 1970s and early 1980s caused many farmers to find ways to reduce their energy costs, such as by switching from gasoline-powered to more fuel-efficient diesel-powered engines, adopting conservation tillage practices, shifting to larger multiprocessor machines, and using energy saving methods for drying and irrigating crops. These measures helped farmers reduce their energy use by 41 percent from 1978 to 1998, while agricultural output grew by about 40 percent over the same period.

Farmers can reap additional energy savings as they replace old machinery with more energy efficient equipment. Furthermore, farmers can adopt more advanced practices, such as precision farming, that optimize the use of machines, chemicals, and fertilizers to achieve energy savings. New seed varieties can also reduce energy-intensive chemical requirements.

Despite the opportunity for increased energy efficiency, the industrial and agricultural sectors face several obstacles. Because many manufacturing and farming operations are highly specialized, they need specific information on energy-saving opportunities to effectively respond to energy price signals and supply problems.

Cogeneration

In 1998, Malden Mills Industries, a textile manufacturer employing 2,300 workers in Lawrence, Massachusetts, installed a state-of-the-art combined heat and power (CHP) facility. The system uses two 4.3 MW industrial gas turbines, retrofitted with ceramic combustion liners, that were developed as part of the Department of Energy's Advanced Turbine Systems program, and that enable higher operating temperatures and lower emissions. The CHP system saves Malden Mills more than $1 million annually. The liners have accumulated more than 9,500 hours of successful operation and have cut emissions of nitrogen oxides and carbon monoxide to less than 15 parts per million.



In order for manufacturing or agriculture to switch to more efficient energy products and practices, significant costs are incurred due to production delays, waste and spoilage, and labor costs. As a result, manufacturers and farmers tend to use readily available and reliable equipment when upgrading, instead of untested, newer products and approaches.

Because of their large needs for both heat and electricity, businesses find combined heat and power (CHP) systems particularly attractive. However, replacing old, inefficient boilers with highly efficient CHP systems may add a number of new regulatory requirements (such as air permits), but does not offer the same tax depreciation incentives the tax code grants to power plants.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with the Congress on legislation to encourage increased energy efficiency through combined heat and power (CHP) projects by shortening the depreciation life for CHP projects or providing an investment tax credit.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to work with local and state governments to promote the use of well-designed CHP and other clean power generation at brownfield sites, consistent with the local communities' interests. EPA will also work to clarify liability issues if they are raised at a particular site.

★ The NEPD Group recommends that the President direct the EPA Administrator to promote CHP through flexibility in environmental permitting.

Conservation can be improved by car pooling, telecommuting, increasing public transit choices, and pricing highway use during periods of peak demand.

Transportation

Transportation plays a key role in a growing U.S. economy, comprising 16 percent of GDP in 1998, 10.5 percent of total employment, and 27 percent of total U.S. energy consumption. Trucks and automobiles account for over three-fourths of the sector's petroleum use, with the remainder attributable to rail, ship, air, and pipeline systems. Mass transit ridership has increased by 21 percent since 1996. Automobiles today use roughly 60 percent of the gasoline they did in 1972 per mile driven, due in part to new technology, such as better engine and design controls, improved transmission, weight reduction, and improved aerodynamics. Despite the adoption of more efficient transportation technologies, average fuel economy for passenger vehicles has remained relatively flat for ten years and is, in fact, at a twenty-year low, in large part due to the growth and popularity of low-fuel-economy pickup trucks, vans, and sport utility vehicles (Figure 4-4).

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Transportation to:

- Review and provide recommendations on establishing Corporate Average Fuel Economy (CAFE) standards with due consideration of the National Academy of Sciences study to be released in July 2001. Responsibly crafted CAFE standards should increase efficiency without negatively impacting the U.S. automotive industry. The determination of future fuel economy standards must therefore be addressed analytically and based on sound science.
- Consider passenger safety, economic concerns, and disparate impact on the U.S. versus foreign fleet of automobiles.
- Look at other market-based approaches to increasing the national average fuel economy of new motor vehicles.

Opportunities for reducing oil demand in the transportation sector include increasing conservation, vehicle efficiency, and alternative fuels. Conservation can be improved by car pooling, telecommuting, and increasing transit choices. For example, an increase in the average fuel economy of the on-road vehicle fleet by three miles per gallon would save one million barrels of oil a day, or about half of the global shortfall between supply and demand that triggered the oil price increases since 1998. In addition, fuel conservation can be further improved by technologies to reduce congestion.

A recent analysis indicates that the fuel economy of a typical automobile could be enhanced by 60 percent by increasing engine and transmission efficiency and reducing vehicle mass by about 15 percent. Several promising efficiency technologies are being presented to the U.S. market. For example, some automobile manufacturers have already introduced hybrid vehicles, and others have announced that they will introduce hybrid vehicles within the next several years. Advanced lightweight materials offer up to 6 percent improvement in mileage for each 10 percent reduction in body weight. Although promising, it may be many years before hybrids become a substantial part of the automotive fleet.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretary of Transportation to review and promote congestion mitigation technologies and strategies and to work with the Congress on legislation to implement these strategies.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to increase energy efficiency with a tax credit for fuel-efficient vehicles. The NEPD Group recommends that a temporary, efficiency-based income tax credit be available for purchase of new hybrid or fuel cell vehicles between 2002 and 2007.

Higher Initial Production Costs

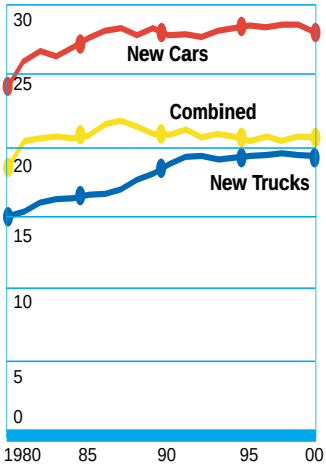
Because of the large economies of scale in automobile manufacturing, new technologies with limited early production runs often enter the market at higher initial costs. In this highly competitive international market, higher initial production costs can be a significant impediment to the introduction of new technologies. Unless U.S. automakers can remain competitive with their overseas counterparts, it is unlikely they will invest in new, more efficient technologies. Vehicle efficiency technologies, such as advanced engines, fuel cells, and cutting-edge electronic drive-train technologies, will become widely available only when component costs are reduced or demand is increased.

Hybrid Vehicles

The engine of a conventional gasoline vehicle is typically sized for the small amount of time the driver spends accelerating to enter the freeway, to pass another car, or to climb a hill. Most of the time it operates at less than 20 percent efficiency. An attractive alternative is to use a hybrid system that allows the engine to operate at peak efficiency, and get a boost from a battery when entering the freeway or climbing a hill. Not only does this system allow improved performance from a smaller engine, but the energy usually lost in stopping the car can be recovered and stored in the battery.

What does this mean to the average American? Significantly improved fuel economy and reduced emissions.

Figure 4-4
Fuel Efficiency of Light Vehicles Has Remained Flat
(Miles per Gallon)



Despite the adoption of more efficient transportation technologies, U.S. average fuel economy has been flat for 10 years. In large part, this is due to the growth of low-fuel-economy pickup trucks, vans, and sport utility vehicles.

Source: U.S. Department of Energy, Energy Information Administration.

Summary of Recommendations

Using Energy Wisely: Increasing Energy Conservation and Efficiency

★ The NEPD Group recommends that the President direct the Office of Science and Technology Policy and the President's Council of Advisors on Science and Technology to review and make recommendations on using the nation's energy resources more efficiently.

★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of energy efficiency research and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.

★ The NEPD Group recommends that the President direct the Secretary of Energy to promote greater energy efficiency.

- Expand the Energy Star program beyond office buildings to include schools, retail buildings, health care facilities, and homes.
- Extend the Energy Star labeling program to additional products, appliances, and services.
- Strengthen Department of Energy public education programs relating to energy efficiency.

★ The NEPD Group recommends that the President direct the Secretary of Energy to improve the energy efficiency of appliances.

- Support the appliance standards program for covered products, setting higher standards where technologically feasible and economically justified.
- Expand the scope of the appliance standards program, setting standards for additional appliances where technologically feasible and economically justified.

★ The NEPD Group recommends that the President direct heads of executive departments and agencies to take appropriate actions to conserve energy use at their facilities to the maximum extent consistent with the effective discharge of public responsibilities. Agencies located in regions where electricity shortages are possible should conserve especially during periods of peak demand. Agencies should report to the President, through the Secretary of Energy, within 30 days on the conservation actions taken.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to encourage increased energy efficiency through combined heat and power (CHP) projects by shortening the depreciation life for CHP projects or providing an investment tax credit.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to work with local and state governments to promote the use of well-designed CHP and other clean power generation at brownfields sites, consistent with the local communities' interests. EPA will also work to clarify liability issues if they are raised at a particular site.

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crafted CAFE standards should increase efficiency without negatively impacting the U.S. automotive industry. The determination of future fuel economy standards must therefore be addressed analytically and based on sound science.
- Consider passenger safety, economic concerns, and disparate impact on the U.S. versus foreign fleet of automobiles.
- Look at other market-based approaches to increasing the national average fuel economy of new motor vehicles.

★ The new NEPD Group recommends that the President direct the Secretary of Transportation to review and promote congestion mitigation technologies and strategies and work with Congress on legislation to implement these strategies.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to increase energy efficiency with a tax credit for fuel-efficient vehicles. The NEPD Group recommends that a temporary, efficiency-based income tax credit be available for purchase of new hybrid fuel cell vehicles between 2002 and 2007.

★ The NEPD Group recommends that the President direct all agencies to use technological advances to better protect our environment.
- The Administration remains committed to investing in Intelligent Transportation Systems (ITS) and encourages the private sector to invest in ITS applications. This Department of Transportation (DOT) program funds the development of improved transportation infrastructure that will reduce congestion, such as traveler information/navigation systems, freeway management, and electronic toll collection. ITS applications reduce fuel associated with travel.
- The Administration remains committed to the DOT's fuel-cell-powered transit bus program, authored by the Transportation Equity Act for the 21st Century (TEA-21). This program demonstrates the viability of fuel-cell power plants for transit bus applications.
- The Administration remains committed to the Clean Buses program. TEA-21 establishes a new clean fuel formula grant program, which provides an opportunity to accelerate the introduction of advanced bus propulsion technologies into the mainstream of the nation's transit fleet.

★ The NEPD Group recommends that the President direct the EPA and DOT to develop ways to reduce demand for petroleum transportation fuels by working with the trucking industry to establish a program to reduce emissions and fuel consumption from long-haul trucks at truck stops by implementing alternatives to idling, such as electrification and auxiliary power units at truck stops along interstate highways. EPA and DOT will develop partnership agreements with trucking fleets, truck stops, and manufacturers of idle-reducing technologies (*e.g.*, portable auxiliary packs, electrification) to install and use low-emission-idling technologies.

★ The NEPD Group recommends that the President direct the Secretary of Energy to establish a national priority for improving energy efficiency. The priority would be to improve the energy intensity of the U.S. economy as measured by the amount of energy required for each dollar of economic productivity. This increased efficiency should be pursued through the combined efforts of industry, consumers, and federal, state, and local governments.

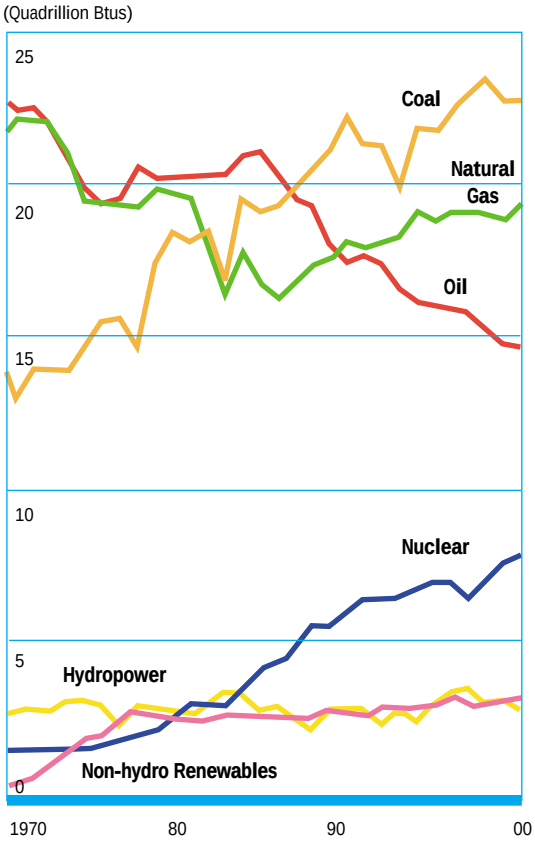
★ The NEPD Group recommends that the President direct the EPA Administrator to develop and implement a strategy to increase public awareness of the sizable savings that energy efficiency offers to homeowners across the country. Typical homeowners can save about 30 percent (about $400) a year on their home energy bill by using Energy Star-labeled products.

Energy for a New Century

Increasing Domestic Energy Supplies

America's energy strength lies in the abundance and diversity of its energy resources, and in its technological leadership in developing and efficiently using these resources. Our nation has rich deposits of coal, oil, and natural gas. The United States is the third-largest oil-producing nation in the world, despite a thirty-year decline in domestic production. While our economy runs primarily on fossil fuels, we also have long experience with hydropower and nuclear energy. We are pursuing the ability to further capture the energy of sunlight, the heat of the earth, and the power of wind.

Figure 5-1
U.S. Energy Production: 1970–2000



Production of coal, the nation's most abundant fuel source, exceeded 1 billion tons in 2000. Electricity generation accounted for about 90 percent of U.S. coal consumption last year.

Source: U.S. Department of Energy, Energy Information Administration.

Economic factors will help determine the future development of our nation's energy sources. These factors will be shaped not only by conservation, energy demand, and the cost of energy development, but also by the regulations that federal, state, and local governments put in place to balance energy needs with legitimate competing aims, including the protection of the environment. A number of factors will make it difficult to increase domestic energy production in response to the growing demand for energy: economic and technological factors associated with depletion of the fossil fuel resource base in the U.S.; regulatory uncertainty; limitations on access to federal lands with high potential for new discoveries; infrastructure constraints, such as electricity transmission and gas pipeline bottlenecks; and conflicts with legitimate land use, environmental, and other public policy goals.

The United States has significant domestic energy resources, and remains a major energy producer. Between 1986 and 2000, production of coal, natural gas, nuclear energy, and renewable energy increased. However, these increases have been largely offset by declines in oil production (Figure 5-1).

U.S. Department of the Interior, Minerals Management Service



Even with improved energy efficiency, the United States will need more energy supply. U.S. energy demand is projected to rise to 127 quadrillion Btus by 2020, even with significantly improved energy efficiency. However, domestic production is expected to rise to only 86 quadrillion Btus by 2020. The shortfall between projected energy supply and demand in 2020 is nearly 50 percent. That shortfall can be made up in only three ways: import more energy; improve energy efficiency even more than expected; and increase domestic energy supply.

The challenge for our nation is to use technology to maintain and enhance the diversity of our supplies, thus providing a reliable and affordable source of energy for Americans. These goals can and must be accomplished while maintaining our commitment to environmental protection.

Oil and Natural Gas

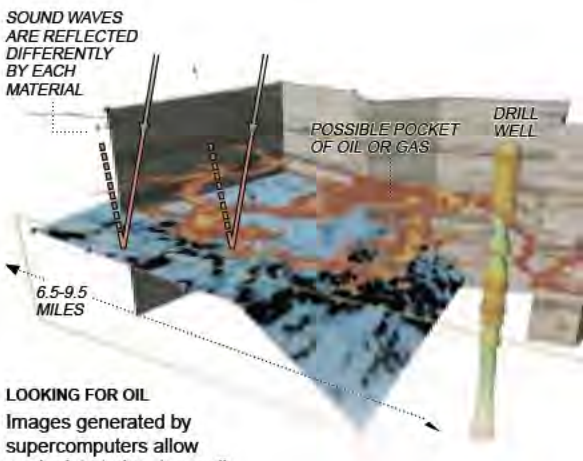
Oil and natural gas are the dominant fuels in the U.S. economy, providing 62 percent of the nation's energy and almost 100 percent of its transportation fuels. By 2020, the Energy Information Administration expects the United States will need about 50 percent more natural gas and one-third more oil to meet demand.

U.S. oil production is expected to decline over the next two decades. Over the same period, demand for natural gas will most likely continue to outpace domestic production. As a result, the United States will rely increasingly on imports of both natural gas and oil from Canada, and imports of oil and liquefied natural gas from producers across the globe.

21st Century Technology

Remaining U.S. oil reserves are becoming increasingly costly to produce because much of the lower-cost oil has already been largely recovered. The remaining resources have higher exploration and production costs and greater technical challenges, because they are located in geologically complex reservoirs, (*e.g.*, deep water

Figure 5-2



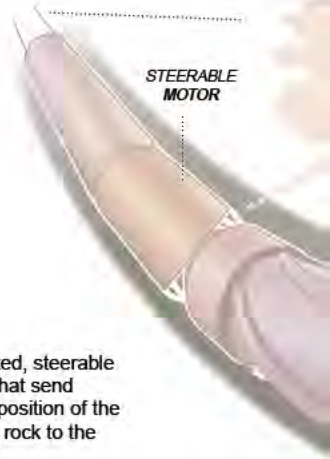
LOOKING FOR OIL
Images generated by supercomputers allow geologists to locate small pockets of oil or gas.



DRILLING TECHNOLOGY
Old drills were limited to a single vertical well, but newer wells can drill horizontally or spread in different directions to tap small pockets of oil.



TRANSPORTING THE OIL
A 14-inch pipeline connects the Alpine field to the Trans-Alaska Pipeline about 60 miles west of the Arctic National Wildlife Refuge, a site proposed for new drilling.



TRANSPORTING THE OIL
Today's drills are sophisticated, steerable machines with instruments that send information about the exact position of the drill bit and properties of the rock to the drilling team.

Sources Phillips Petroleum Company, Chevron Corporation, BP Amoco, Magic Earth, Arctic Connections

DRILL BIT MADE OF STEEL AND/OR TUNGSTEN

Using the Latest Drilling Technology to Reduce Environmental Damage

Oil drilling sites like those in the Alpine field on Alaska's North Slope are using cutting-edge technology in hopes of reducing environmental damage.

Recent advances are lessening the industry's impact on the fragile Arctic ecosystem.



BP Amoco

ALPINE FIELD, ALASKA

A PIPELINE ELEVATED 5 FT. ALLOWS THE CROSSING OF CARIBOU

PIPELINE TO THE TRANS-ALASKA PIPELINE

NEW DIRECTIONAL AND MULTILATERALDRILLING

DISPOSING OF OIL FIELD WASTES

EXTENDS HORIZONTALLY, TURNING IN DIFERRENT DIRECTIONS TO AVOID DIFFICULT MATERIALS

MULTILATERAL DRILLING ALLOWS ONE WELL TO REACH DIFFERENT OIL POCKETS

DIAMOND CUTTING PARTS

MUD/ROCK PUMPING, CRUSHING AND INJECTION

DRILL

MUD LAYER

OIL LAYER

Sea level

-50'

-100'

Pipeline

Permafrost

DRILLSITE SIZE

5 ACRES

24 ACRES

11 ACRES

13 ACRES

1970

1980

1985

1999

2 MILES

3 MILES

5 MILES

8 MILES

SUBSURFACE DRILLABLE AREA

GETTING THERE

To minimize the project's impact on the environment, temporary ice roads are used in the winter, leaving few traces after they thaw.

DISPOSING OF WASTES

Mud and debris from drilling used to be placed in big reserve pits. Today, rock cuttings are crushed, mixed with the mud, and sent deep into the earth where they originated. This minimizes the size of well pads.

CROSSING A RIVER

Although traditional pipelines are built above ground, the pipeline to the Trans-Alaska Pipeline plunges beneath the Colville River, preserving the surface and the river bed environment.

OCCUPYING LESS OF THE TUNDRA

The new drilling technology allows for smaller surface production pads and larger areas explored in the earth.

Source: New York Times News Service

21st Century Technology: The Key to Environmental Protection and New Energy Production

Producing oil and gas from geologically challenging areas while protecting the environment is important to Americans and to the future of our nation's energy security. New technology and management techniques allow for sophisticated energy production as well as enhanced environmental protection. A technology evolution has occurred in the way oil and natural gas are found. The computer, three dimensional seismic technology, and other technologies have transformed the process from one based on "feel," to one highly dependent on the most advanced and sophisticated technology available. These technologies reduce cost and protect the environment.

Today's oil and gas exploration technology, for example, is boosting the success rate of pinpointing new resources. The results: fewer dry holes, reduced waste volumes, and a cleaner environment. Smaller, lighter drilling rigs coupled with advances in directional and extended-reach drilling significantly increase protection of the environment.

- Advanced, more energy efficient drilling and production methods:
  - — reduce emissions;
  - — practically eliminate spills from offshore platforms; and
  - — enhance worker safety, lower risk of blowouts, and provide better protection of groundwater resources.
- With each improvement in operational performance and efficiency, more oil and gas resources can be recovered with fewer wells drilled, resulting in smaller volumes of:
  - — cuttings;
  - — drilling muds and fluids; and
  - — produced waters.
- Modular drilling rigs, "slimhole" drilling, directional drilling, and other advances enable:
  - — production of oil and gas with increased protection to wetlands and other sensitive environments;
  - — reduced greenhouse gas emissions;
    and worker safety through the use of innovative best management practices.

Other examples of advanced technology include:

- 3-D seismic technology that enables geologists to use computers to determine the location of oil and gas before drilling begins, dramatically improving the exploration success rate;
- deep-water drilling technology that enables exploration and production of oil and gas at depths over two miles beneath the ocean's surface;
- high-powered lasers that may one day be used for drilling for oil and gas; and
- highly sophisticated directional drilling that enables wells to be drilled long horizontal distances from the drilling site.

:

and harsh environments).

While the resource base that supplies today's natural gas is vast, U.S. conventional production is projected to peak as early as 2015. Increasingly, the nation will have to rely on natural gas from unconventional resources, such as tight sands, deep formations, deep water, and gas hydrates. Also, many resources are in environmentally sensitive areas that require use of less intrusive technologies.

New technologies are being developed to reduce both the environmental effects and the economic costs of exploration for oil and gas. These exciting new technologies, like horizontal drilling and three-dimensional seismic technology allow for much greater precision and significantly less impact on the environment (Figure 5-2).

Small independent businesses account for 50 and 65 percent, respectively, of domestic petroleum and natural gas production in the lower 48 states. However, even when new technology is available, independent producers can lack the investment capital needed to apply the technology and be unable to cope with the increased economic and technical risks associated with harder-to-recover resources.

For example, most new gas wells drilled in the United States will require hydraulic fracturing. This is a common procedure used by producers to complete gas wells by stimulating the well's ability to flow increased volumes of gas from the reservoir rock into the wellbore. During a fracture procedure, fluid and a propping agent (usually sand) are pumped into the reservoir rock, widening natural fractures to provide paths for the gas to migrate to the wellbore. In certain formations, it has been demonstrated that the gas flow rate may be increased as much as twenty-fold by hydraulic fracturing. Each year nearly 25,000 oil and gas wells are hydraulically fractured.

The use of hydraulic fracturing in natural gas production from coal seams is one of the fastest-growing sources of gas production. This source will most likely face added controls, and costs to ensure that disposal (by re-injection or discharge) of production waters is done in an environmentally sensitive manner.

For each of these issues, opportunities exist to better coordinate, improve performance, and meet America's energy, public health, safety and environmental goals.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of Energy and the Interior to promote enhanced oil and gas recovery from existing wells through new technology.

Anywhere from 30 to 70 percent of oil, and 10 to 20 percent of natural gas, is not recovered in field development. It is estimated that enhanced oil recovery projects, including development of new recovery techniques, could add about 60 billion barrels of oil nationwide through increased use of existing fields (Figure 5-3).

Figure 5-3
Major U.S. Oil and Gas Fields



The United States is the most mature oil-producing region in the world, and much of our easy-to-find resource base has been delpeted. Advanced exploration and production technologies of the past two decades have played a key role in recovering additional oil and natural gas from existing fields.

Source: U.S. Department of Energy, Energy Information Administration.

Public Lands Leasing

The federal government owns about 31 percent of the nation's land, so it can have a major role in increasing energy production in appropriate places. A large portion of U.S. energy resources are contained in these federal lands and offshore areas. Public lands provide nearly 30 percent of

Small independent businesses account for 50 and 65 percent, respectively, of domestic petroleum and natural gas production in the lower 48 states.

annual national energy production, and are estimated to contain a substantial majority of the nation's undiscovered domestic energy resources.

Portions of federal onshore and offshore lands are off-limits to oil and gas exploration and development. Access is restricted for a variety of reasons, including administrative land withdrawals for competing land uses, such as national defense or water projects; and stipulations affecting surface occupancy, use, and timing for environmental compatibility.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretary of the Interior to examine land status and lease stipulation impediments to federal oil and gas leasing, and review and modify those where opportunities exist (consistent with the law, good environmental practice, and balanced use of other resources).

- Expedite the ongoing Energy Policy and Conservation Act study of impediments to federal oil and gas exploration and development.
- Review public lands withdrawals and lease stipulations, with full public consultation, especially with the people in the region, to consider modifications where appropriate.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider economic incentives for environmentally sound offshore oil and gas development where warranted by specific circumstances: explore opportunities for royalty reductions, consistent with ensuring a fair return to the public where warranted for enhanced oil and gas recovery; for reduction of risk associated with production in frontier areas or deep gas formations; and for development of small fields that would otherwise be uneconomic.

Offshore

Congress has designated about 610 million acres off limits to leasing on the Outer Continental Shelf (OCS), which contains large amounts of recoverable oil and gas resources. These Congressional moratoria have been expanded by Presidential action through 2012, effectively confining the federal OCS leasing program to the central and western Gulf of Mexico, a small portion of the eastern Gulf, existing leases off California's shore, and areas off of Alaska.

Concerns over the potential impacts of oil spills have been a major factor behind imposition of the OCS moratoria. For areas that are available for possible development, it is projected that with advanced technology, we could recover 59 billion barrels of oil and 300 trillion cubic feet of natural gas. This type of exploration and production from the OCS has an impressive environmental record. For example, since 1985, OCS operators have produced over 6.3 billion barrels of oil, and have spilled only 0.001 percent of production. Naturally occurring oil seeps add about 150 times as much oil to the oceans. Additionally, about 62 percent of OCS energy production is natural gas, which poses little risk of pollution.

For those areas that are available for potential coastal zone and OCS exploration and production activity, businesses must comply with a variety of federal and state statutes, regulations, and executive orders. Aspects of these, under the Coastal Zone Management Act and the Outer Continental Shelf Lands Act and their regulations, attempt to provide for responsible development while considering important environmental resources. However, effectiveness is sometimes lost through a lack of clearly defined requirements and information needs from federal and state entities, as well as uncertain deadlines during the process. These delays and uncertainties can hinder proper energy exploration and production projects.

The Deep Water Royalty Relief Act of 1995, granting variable royalty reductions for new leases in deep water, contributed to a significant increase in deep-water leasing in the central and western Gulf over the last five years. The opportunities created in deep water help spur the development of new

technologies and infrastructure for this frontier area. However, substantial economic risks remain to investment in deep water and continued incentives could help draw investment in other countries. Similar incentives could spur development in other technological frontiers, such as deep gas, or make possible continued production from both offshore and onshore fields near the end of their economic life.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Interior to re-examine the current federal legal and policy regime (statutes, regulations, and Executive Orders) to determine if changes are needed regarding energy-related activities and the siting of energy facilities in the coastal zone and on the Outer Continental Shelf (OCS).

Arctic Outer Continental Shelf

It is estimated there are significant undiscovered resources in the two planning areas of the Arctic OCS. Geologists estimate that there are approximately 22.5 billion barrels of oil and 92 trillion cubic feet of natural gas in the Arctic OCS. The Beaufort Sea Planning Area encompasses approximately 65 million acres. Active leases within the Beaufort Sea Planning Area represent only 0.4 percent of the total acreage, and only 5 percent of the leased acreage is being actively pursued for development and production. The Chukchi Sea Planning Area encompasses approximately 63.7 million acres, none of which is currently leased.

Lease offerings totaling 58 million acres over the past twenty years have resulted in 34 exploratory wells. Two oil discoveries are now moving toward production, but economic factors have delayed several others. These discoveries have estimated recoverable reserves of more than 260 million barrels of oil. This is another area where periodic, well-scheduled lease sales can help contribute to national energy production.



The high-technology oil industry requires an educated, technologically sophisticated work force. Many workers left the industry in the mid-1980s because of job insecurity caused by price volatility. The lack of an experienced work force today may limit the amount and increase the cost of future exploration and production activity.

U.S. Department of Energy

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Interior continue OCS oil and gas leasing and approval of exploration and development plans on predictable schedules.

Onshore

North Slope Oil and Gas

The Alaska North Slope is a promising area for discovery of additional reserves to increase our domestic production of oil and natural gas. Currently, state lands on Alaska's North Slope provide about 17 percent of U.S. oil production. Oil and gas development in the Arctic, however, needs to be done in an environmentally responsible manner, using new technology and relying upon on the best available scientific information. Such technology is making it possible to explore and develop oil and gas with significantly less impact on the environment. Areas with potential for oil and gas development are the National Petroleum Reserve–Alaska (NPR–A), the Arctic Outer Continental Shelf, and the Arctic National Wildlife Refuge (ANWR).

National Petroleum Reserve–Alaska

The National Petroleum Reserve–Alaska lies between the Brooks Range and the Arctic Ocean. The U.S. Geological Survey (USGS) estimates a high potential for oil and gas resources in the NPR–A, with a mean estimate of 2.1 billion barrels of oil and 8.5 trillion cubic feet of gas. A leasing program was designed and initiated in 1999 for the northeast sector of NPR–A, resulting in the award of 133 leases covering 900,000 acres. Eight exploratory wells have been completed in the past two years, and additional exploratory wells are expected this coming winter.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider additional environmentally responsible oil and gas development, based on sound science and the best available technology, through further lease sales in the National Petroleum Reserve-Alaska. Such consideration should include areas not currently leased within the Northeast corner of the Reserve.

Arctic National Wildlife Refuge

The Alaska National Interest Lands Conservation Act expanded ANWR from 9 million acres to 19 million acres, and designated 8 million acres as wilderness. Congress specifically left open the question of management of a 1.5-million-acre Arctic Coastal Plain area of ANWR because of the likelihood that it contains significant oil and gas resources. Section 1002 of the Act directed the Department of the Interior to conduct geological and biological studies of the Arctic Coastal Plain, "the 1002 Area," and to provide to Congress the results of those studies with recommendations on future management of the area. Section 1003 of the Act prohibits leasing of the 1002 Area until authorized by an act of Congress.

In 1987, after more than five years of biological baseline studies, surface geological studies, and two seasons of seismic exploration surveys, the Department of the Interior recommended to Congress that the 1002 Area be leased for oil and gas exploration and production in an environmentally sensitive manner. In 1995, both the Senate and the House passed legislation containing a provision to authorize leasing in the 1002 Area, but the legislation was vetoed.

In May 1998, the USGS issued revised estimates of oil and gas resources in the 1002 Area. The 1998 USGS assessment shows an overall increase in estimated oil resources when compared to all previous government estimates. The estimate reaffirms the 1002 Area's potential as the single most promising prospect in the United States. The total quantity of recoverable oil within the entire assessment area is estimated to be between 5.7 and 16 billion barrels (95 percent and 5 percent probability range) with a mean value of 10.4 billion barrels. The mean estimate of 10.4 billion barrels is just below the amount produced to date from North America's largest field, Prudhoe Bay, since production began 23 years ago. Peak production from ANWR could to be between 1 and 1.3 million barrels a day and account for more than 20 percent of all U.S. oil production. ANWR production could equal 46 years of current oil imports from Iraq.

Technological improvements over the past 40 years have dramatically reduced industry's footprint on the tundra, minimized waste produced, and protected the land for resident and migratory wildlife. These advances include the use of ice roads and drilling pads, low-impact exploration approaches such as winter-only exploration activities, and extended reach and through-tubing rotary drilling. These technologies have significantly reduced the size of production-related facilities on the North Slope. Estimates indicate that no more than 2,000 acres will be disturbed if the 1002 Area of ANWR is developed. For purposes of comparison, ANWR is about the size of the state of South Carolina, whereas the developed area is estimated to be less than one-fifth the size of Washington D.C.'s Dulles International Airport.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress to authorize exploration and, if resources are discovered, development of the 1002 Area of ANWR. Congress should require the use of the best available technology and should require that activities will result in no significant adverse impact to the surrounding environment.

Other Onshore Restrictions

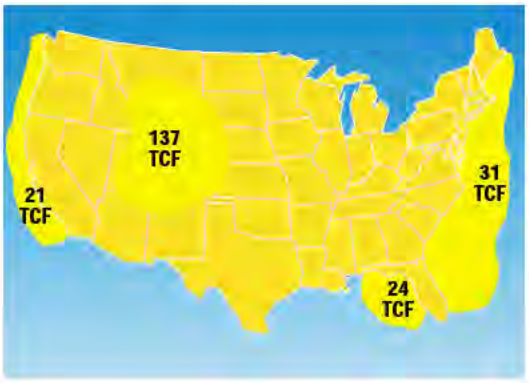
There is a significant potential for oil and gas resources on federal land in the lower 48 states as well. According to the most recent estimates from the USGS and the Minerals Management Service, oil resources underlying federal lands in the lower 48 states are estimated to be 4.1 billion barrels, and natural gas reserves are estimated to be 167 trillion cubic feet (Figure 5-4). Much of these potential resources have been placed off-limits or are subject to significant restrictions. For example, about 40 percent of the natural gas resources on federal land in the Rocky Mountain region have been placed off-limits.

The Department of the Interior initiated a study to examine the energy potential and restrictions on development on federal lands in the lower 48 states. In many cases, limits on oil and gas development are appropriate. However, improved technology has helped to reduce the impact of oil and gas development on the environment.

Exploration and Production

To meet increased natural gas demand in the coming decades, total wells drilled annually will need to double the 1999 level by 2020. Very few new onshore rigs have been built since the mid-1980s, because the oil field supply and service sectors have been hit especially hard by price volatility. Major additions to the offshore rig fleet will also be needed just to develop existing leases. The lack of an experienced work force may limit the speed and increase the cost of exploration and production activity.

Figure 5-4
Restricted Natural Gas Resource Areas in the U.S. Lower 48



Much of the nation's oil and gas resource base resides on federal lands or in federal waters. A large portion of this is not open to exploration and development. For example, an estimated 40 percent or 137 trillion cubic feet of potential natural gas resource in the Rockies is either closed to exploration (29 tcf) or is open to development under restrictive provisions (108 tcf).

Source: U.S. Department of Energy, Energy Information Administration.

Electricity

Electricity is an essential part of modern life. When supply fails to keep pace with demand, costs to consumers and businesses rise and reliability falls. The California experience demonstrates the crippling effect that electricity shortages and blackouts can have on a state or region. This summer, the possibility exists for more intense electricity shortfalls in the West, with additional problems possible in New York City and on Long Island.

Electricity demand is projected to grow sharply over the next twenty years. Based on current estimates, the United States will need about 393,000 MW of new generating capacity by 2020 to meet the growing demand. If the U.S. electricity demand continues to grow at the high rate it has recently, we will need even more generating capacity. To meet that future demand, the United States will have to build between 1,300 to 1,900 new power plants; that averages out to be more than 60 to 90 plants a year, or more than one a week.

Over the next few years, if the demand for electricity continues to grow as predicted, and if we fail to implement a

comprehensive energy plan that recognizes the need to increase capacity, we can expect our electricity shortage problems to grow. The result will be higher costs and lower reliability.

Electricity Restructuring

One of the most important energy issues facing the Administration and Congress is electricity restructuring. The electricity industry is going through a period of dramatic change. To provide ample electricity supplies at reasonable prices, states are opening their retail markets to competition. This is the most recent step in a long transition from reliance on regulation to reliance on competitive forces.

Changes in Wholesale Electricity Market

This transition from regulation to competition began in 1978 with enactment of the Public Utility Regulatory Policies Act, which promoted independent electricity generation. Open-access transmission policies adopted by the Federal Energy Regulatory Commission (FERC) in the late 1980s further promoted competition in wholesale power markets. Congress largely ratified these policies with enactment of the Energy Policy Act of 1992, which further promoted non-utility generation. FERC took another large step to promote competition with its open-access rule in 1996, which provided greater access to the transmission grid, the highway for interstate commerce in electricity.

Electricity demand is projected to rise sharply over the next twenty years. If we fail to build the 1,300–1,900 new power plants needed to increase generation and transmission capacity, current electricity shortages will become more frequent and more widespread.
U.S. Department of Energy



Changes in the Retail Electricity Market

Increased competition in wholesale power markets encourages states to open retail electricity markets. Under current law, FERC has jurisdiction over the wholesale power market, while states have jurisdiction over retail markets. Beginning in 1996, states began opening their retail markets to competition in order to lower electricity prices. Twenty-five states have opted to open their retail electricity markets to competition.

Most new electricity generation is being built not by regulated utilities, but by independent power producers. These companies assume the financial risk of investment in new generation, and their success rides on their ability to generate electricity at a low cost.

These dramatic changes affecting the industry led to important structural changes. Independent power producers, which were once infant industries, now dwarf many utilities. Utility mergers, which were once rare, are now commonplace. U.S. utilities have been purchased by foreign companies, and U.S. utilities have in turn purchased utilities abroad. While utilities had service areas that were limited to a single state or region, independent power producers are international companies that can build power plants across the globe. Many utilities that were once vertically integrated divested themselves of generation, either voluntarily or because of state law.

Pending Congressional Action

Since 1995, Congress has been grappling with electricity competition legislation. Initial efforts sought to require states to open their retail markets by a date certain. Subsequent efforts focused on promoting competition in electricity markets and complementing state retail competition plans. Under this

approach, federal legislation focused on core federal issues, including:

- regulation of interstate commerce;
- assuring open access to the interstate and international transmission system;
- enhancing reliability of the grid;
- lowering barriers to entry;
- reforming outdated federal electricity laws, such as the Public Utility Holding Company Act and Public Utility Regulatory Policies Act of 1978;
- reforming the role of federal electric utilities in competitive markets;
- protecting consumers; and
- clarifying federal and state regulatory jurisdictions.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretary of Energy to propose comprehensive electricity legislation that promotes competition, protects consumers, enhances reliability, improves efficiency, promotes renewable energy, repeals the Public Utility Holding Company Act, and reforms the Public Utility Regulatory Policies Act.

★ The NEPD Group recommends the President encourage FERC to use its existing statutory authority to promote competition and encourage investment in transmission facilities.

California Electricity Crisis

The California electricity crisis is not a test of the merits of competition in electricity markets. Instead, it demonstrates that a poorly designed state retail competition plan can have disastrous results if electricity supply does not keep pace with increased demand. At heart, the California electricity crisis is a supply crisis. California allowed demand to outstrip supply, and did little to lower barriers to entry through reform of an inflexible siting process. The risk that the California experience will repeat itself is low, since other states have not modeled their retail competition plans on California's plan.

The California crisis also shows that state electricity markets do not stay neatly confined within legal and jurisdictional bounds. Due to regional interconnection, disastrous mistakes made by the State of California have dire effects on the entire West. California's failure to reform flawed regulatory rules affecting the market drove up wholesale prices. Actions such as forcing utilities to purchase all their power through volatile spot markets, imposing a single-price auction system, and barring bilateral contracts all contributed to the problems that California now faces.

Lessons Learned from Successful Deregulation

As stated previously, 25 states have decided to open their retail electricity markets. A comparison of the different approaches taken by California and other states demonstrates that competition will benefit consumers if implemented effectively. A better gauge of the potential for retail competition to lower prices can be found in Pennsylvania, where electricity prices have fallen significantly as a result of competition. There is also reason to believe that the plan in Texas will have similar success.

A major difference between the California experience and the approaches taken by Pennsylvania and Texas is that the latter states ensured they had adequate electricity supplies. Pennsylvania and Texas took steps to ensure that procedures for adding new power plants were efficient. Unlike California, which imports 25 percent of its electricity, Pennsylvania is a net exporter of power, and Texas imports almost no power from other states. For these reasons, Pennsylvania and Texas have ample electricity supply to meet demand, while California is confronting a serious supply shortage.

In addition, California required its utilities to divest themselves of much of their generation, unlike Pennsylvania and Texas. This action forced California utilities to rely much more heavily on buying power, at ever-increasing prices, instead of generating power themselves.

Another major difference is that Pennsylvania and Texas did not require their utilities to purchase electricity through volatile spot markets. This requirement, combined with frozen retail rates imposed by the State, forced California utilities to purchase power at much higher costs than could be passed along to the consumer. As a result, the California regulatory plan resulted in unreliable service, destroyed the financial health of the State's utilities, and drove one utility into bankruptcy.

The federal government does not site power plants; that is a responsibility of the states. For that reason, delays relating to the construction of new power plants are usually the result of state action. A number of federal agencies, such as the Environmental Protection Agency, the Department of Commerce, and the Department of the Interior, do issue air and other permits for generation facilities. Some of the concerns about permitting or review delays in other states can be similarly addressed by expediting processes. These agencies, pursuant to President Bush's Executive Order, have expedited permit-processing applications for energy production in California.

Some of the concerns about permitting or review delays in other states can be similarly addressed by expediting processes.For example, in 1999–2000, the time for issuing air permits (including the time for public participation) for turbines was reduced to three to four months (compared to the twelve months allowed by the regulations) for the majority of permit applications.

Fuels for Electricity Generation

Electricity is not a primary source of energy. It is generated by the use of primary energy sources (Figure 5-5). Coal, nuclear energy, natural gas and hydropower account for about 95 percent of total electricity generation, with oil and renewable energy contributing the remainder. Despite this healthy diversity of energy sources, each type of electricity resource is faced with constraints to maintaining or expanding its contribution to electricity production.

Coal

Coal is used almost exclusively to generate electricity. Coal power plants account for over 50 percent of all U.S. electricity generation, and over 80 percent of generation in twelve states in the Midwest, Southeast, and West. Coal electricity generation costs are low, and coal prices have proved remarkably stable. In 1999, the United States produced 1.1 billion tons of coal. Production of coal from federal and tribal lands, which has increased substantially in the past decade, accounted for 38 percent of this total.

Although coal is the nation's most abundant fossil energy source, production and market issues can affect the adequacy of supply. Production issues include the protection of public health, safety, property, and the environment, and the effectiveness of federal and state agencies implementing various laws governing coal mining. These issues have resulted in some coal resources becoming uneconomical to produce. Statutory, regulatory, and administrative difficulties also may limit or prevent the production of some coal resources. However, technological advances in cleaner coal technology have allowed for significant progress toward reducing these barriers. There are also opportunities to protect the environment while lowering costs through further improvements in technology.

Over the past decade, greater efficiencies, lower capital costs, fewer emissions and quicker start-up times have made power plants fueled by natural gas a more attractive choice for new coal generation. Recently, however, rising natural gas prices have renewed interest in building coal power plants.

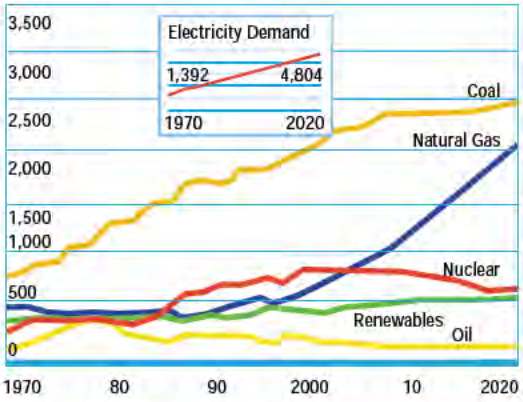
Uncertainty about future environmental controls is of particular concern for companies that operate existing coal power plants. Regulations under development include a variety of measures requiring reductions in emissions of nitrogen oxide, sulfur dioxide, and mercury. In addition, rules related to discharges to streams and cooling-water intake structures, possible regulation of large-volume wastes as hazardous wastes,

uncertainty over rules requiring air permits for certain modifications to power plants, and uncertainty over global and domestic efforts to reduce carbon dioxide emissions also play a role. This regulatory uncertainty discourages power producers from building coal power plants and is one reason the Unites States is relying so heavily on natural gas power generation to meet growing electricity demand.

Much of the current uncertainty has resulted because regulators do not weigh the cumulative impacts of their proposals. Compliance decisions by businesses concerning each new regulation must often be made without the benefit of clear information regarding additional requirements that may be imposed. More effective and economical compliance strategies are possible if companies know the full range of requirements with which they must comply.

If rising U.S. electricity demand is to be met, then coal must play a significant role. Under current policies, in the next two decades, nuclear electricity generation and hydropower are projected to decline. Natural gas electricity generation is projected to increase from about 16 to 36 percent of total generation, which would require the tripling of natural gas used for electricity generation. Significantly, this projected increase in natural gas generation assumes that coal electricity generation will continue to account for about 50 percent of U.S. electricity generation. If policies are adopted that sharply lower coal electricity generation, then the likely result is an even greater dependence on natural gas generation. This creates concern about the adequacy of natural gas supplies and policies.

Figure 5-5
Electricity Generation by Fuel: Current Trends
(Billions of Kilowatt-Hours)



Source: U.S. Department of Energy, Energy Information Administration

Clean Coal Technology

Technology has been and will continue to be a key to achieving our energy, economic, and environmental goals. In recent years, technological advancements through efforts of both the public and private sectors have led to substantial reductions in the cost of controlling sulfur dioxide and nitrogen oxide emissions, while the effectiveness of control systems increased significantly. The Department of Energy, through its Clean Coal Technology Program, has worked to provide effective control technologies. These nitrogen oxide and sulfur dioxide control technologies have moved into the utility marketplace and now provide a means to achieve cost effective regulatory compliance.

For example, most power plants that can use low nitrogen oxide burners have now installed them, and about 25 percent of all coal power plants have either ordered or installed selective catalytic reduction technology, which reduces nitrogen oxide emissions.

Technologies like fluidized-bed combustion and integrated gasification combined cycle have been developed that further reduce emissions. Fluidized-bed combustion is a low-emitting nitrogen oxide combustion technology that allows the use of fuels, such as coal pile washer waste, that were not formerly usable. Integrated gasification combined cycle is a relatively new technology that uses refinery waste as fuel.

Future coal electricity generation will need to meet new challenges to reduce emissions even further, especially mercury emissions. The Department of Energy is supporting efforts to develop more cost effective control technology. Indeed, the goal

Clean Coal Technology

Clean Coal Technology describes a category of technologies that allow for the use of coal to generate electricity while meeting environmental regulations at low cost.

- In the short term, the goal of the program is to meet existing and emerging environmental regulations, which will dramatically reduce compliance costs for controlled mercury, NOx, SO_2, and fine particulate at new and existing coal power plants.
- In the mid-term, the goal of the program is to develop low-cost, super-clean coal power plants, with efficiencies 50 percent higher than today's average. The higher efficiencies will reduce emissions at minimal costs.
- In the long term, the goal of the program is to develop low-cost, zero-emission power plants with efficiencies close to double that of today's fleet.

of these research, development, and demonstration programs is to develop and demonstrate coal power systems with near zero environmental emissions, while maintaining low production costs.

Recommendations:

★ The NEPD Group recognizes the importance of looking to technology to help us meet the goals of increasing electricity generation while protecting our environment. To that end, the NEPD Group recommends that the President direct the Department of Energy to continue to develop advanced clean coal technology by:

- Investing $2 billion over 10 years to fund research in clean coal technologies.
- Supporting a permanent extension of the existing R&D tax credit.
- Directing agencies to explore regulatory approaches that will encourage advancements in environmental technology.

★ The NEPD Group recommends that the President direct federal agencies to provide greater regulatory certainty relating to coal electricity generation through clear policies that are easily applied to business decisions.

Nuclear Energy

Nuclear energy accounts for 20 percent of all U.S. electricity generation, and more than 40 percent of the electricity generation in ten states in the Northeast, the South, and the Midwest. Despite the closure of several less efficient plants during the 1990s, the 103 U.S. nuclear energy plants currently operating produce more electricity today than at any time in history.

There are a number of reasons why nuclear energy expansion halted in the 1980s. Regulatory changes implemented after the Three Mile Island incident in 1979 lengthened the licensing period to an average of fourteen years, resulting in large cost overruns. Increased public concern about the safety of nuclear energy after the accident often resulted in active opposition to proposed plants. As a result, the last completed nuclear energy plant in the United States was ordered in 1973.

Since the 1980s, the performance of nuclear energy plant operations has substantially improved. While U.S. nuclear energy plants once generated electricity only around 70 percent of the time, the average plant today is generating electricity close to 90 percent. This improved performance has lowered the cost of nuclear generation, which is now competitive with other sources of electricity (Figure 5-6).

There is potential for even greater generation from existing nuclear energy plants. Experts estimate that 2,000 MW could be added from existing nuclear power plants by increasing operating performance to 92 percent. In addition, about 12,000 MW of additional nuclear electricity generation could be derived from uprating U.S. nuclear power plants, a process that uses new technologies and methods to increase rated power levels without decreasing safety. However, modifications to uprate plants can be expensive and require extensive licensing review and approval by the Nuclear Regulatory Commission (NRC). Another way to increase nuclear generation from existing plants is through license renewal. Many nuclear utilities are planning to extend the operating license of existing nuclear plants by twenty years, and the licenses of as many as 90 percent of the currently operating nuclear plants may be renewed.

The nuclear energy industry is closely regulated by the NRC, which provides rigorous oversight of the operation and maintenance of these plants. This oversight includes a comprehensive inspection program that focuses on the most significant potential risks of plant operations and features full-time resident inspectors at each plant, as well as regional inspectors with specialized expertise. The NRC has made great strides to provide greater regulatory certainty while maintaining high safety standards.

The installation of new design features, improvements in operating experience, nuclear safety research, and operator training have all contributed to the strong safety record of the nuclear energy industry. Since the Three Mile Island incident in 1979, the nuclear industry's safety record has significantly improved. This safety record has been achieved through a defense-in-depth philosophy accomplished by way of engineering design, quality construction, safe operation, and emergency planning. This philosophy provides for diverse and redundant systems to prevent accidents from occurring, as well as multiple safety barriers to mitigate the effects of accidents in the highly unlikely event they do occur.

Over the last several years, utilities have begun purchasing nuclear plants from other operators as the industry undergoes consolidation. Several nuclear utilities have merged, creating management teams with extensive expertise in running and maintaining nuclear plants. These mergers are impeded by tax rules relating to the transfer of decommissioning funds.

Utilities are also considering nuclear energy as an option for new generation. The NRC has certified three standardized nuclear power plant designs, and Congress enacted legislation in 1992 to reform the nuclear licensing process. Under this process, a utility can apply for a combined construction and operating license for one of these standardized designs in a streamlined process. This reformed licensing process provides for site permits—a way to resolve siting issues early in the process. Building new generators on existing sites avoids many complex issues associated with building plants on new sites. Many U.S. nuclear plant sites were designed to host four to six reactors, and most operate only two or three; many sites across the country could host additional plants.

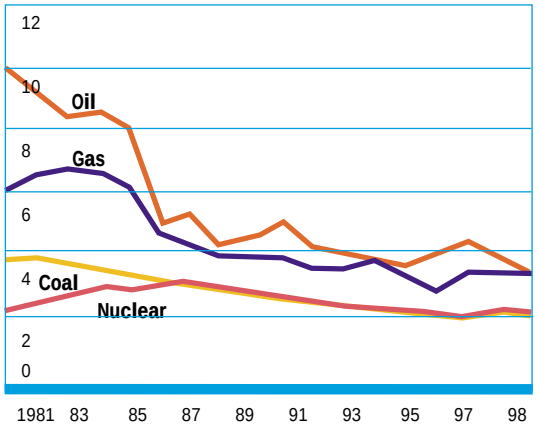
Advanced reactor technology promises to improve nuclear safety. One example of an advanced reactor design is the gas-cooled, pebble-bed reactor, which has inherent safety features. The industry has an interest in this and other advanced reactor designs.

The federal government must also provide for the safe disposal of nuclear waste. At present, nuclear waste continues to be stored at local plant sites. The Department of Energy is over a decade behind schedule for accepting nuclear waste from utilities, but has made progress toward characterization of the Yucca Mountain, Nevada site. Construction of an exploratory studies facility has been completed, a viability assessment was published, and recently scientists placed their extensive research about Yucca Mountain on the record for public scrutiny. However, key regulatory standards to protect public health and the environment at the repository have not been issued.

The Administration will continue to study the science to determine whether to proceed with the consideration of this site as the location for the repository. If the Administration decides to proceed, the Department of Energy must file a license application with the NRC. No waste will be sent to any location until the NRC determines it to be safe.

Other countries have developed different approaches for nuclear waste disposal. For example, the French, British and Japanese rely on reprocessing, an in-

Figure 5-6
Nuclear Generation is Competitively Priced
(1998 Cents per Kilowatt-Hour)



Note: Fuel costs are included.
Source: Utility Data Institute via the Nuclear Energy Institute.



Calvert Cliffs is the first U.S. nuclear plant to receive a renewed license from the Nuclear Regulatory Commission. The renewal will allow the plant to continue producing environmentally sound electricity for an additional twenty years.
CONSTELLATION ENERGY GROUP

dustrial approach that separates nuclear waste into usable fuel and highly concentrated waste. While this approach does not obviate the need for geologic disposal of nuclear waste, it could significantly optimize the use of a geologic repository. There is growing interest in new technology known as accelerator transmutation, which could be used in combination with reprocessing to reduce the quantity and toxicity of nuclear waste.

Recommendations:

★ The NEPD Group recommends that the President support the expansion of nuclear energy in the United States as a major component of our national energy policy. Following are specific components of the recommendation:

- Encourage the Nuclear Regulatory Commission (NRC) to ensure that safety and environmental protection are high priorities as they prepare to evaluate and expedite applications for licensing new advanced-technology nuclear reactors.
- Encourage the NRC to facilitate efforts by utilities to expand nuclear energy generation in the United States by uprating existing nuclear plants safely.
- Encourage the NRC to relicense existing nuclear plants that meet or exceed safety standards.
- Direct the Secretary of Energy and the Administrator of the Environmental Protection Agency to assess the potential of nuclear energy to improve air quality.
- Increase resources as necessary for nuclear safety enforcement in light of the potential increase in generation.
- Use the best science to provide a deep geologic repository for nuclear waste.
- Support legislation clarifying that qualified funds set aside by plant owners for eventual decommissioning will not be taxed as part of the transaction.
- Support legislation to extend the Price–Anderson Act.

★ The NEPD Group recommends that, in the context of developing advanced nuclear fuel cycles and next generation technologies for nuclear energy, the United States should reexamine its policies to allow for research, development and deployment of fuel conditioning methods (such as pyroprocessing) that reduce waste streams and enhance proliferation resistance. In doing so, the United States will continue to discourage the accumulation of separated plutonium, worldwide.

★ The United States should also consider technologies, in collaboration with international partners with highly developed fuel cycles and a record of close cooperation, to develop reprocessing and fuel treatment technologies that are cleaner, more efficient, less waste-intensive, and more proliferation-resistant.

Hydropower

Although hydropower generation accounts for only about 7 percent of overall U.S. electricity generation, the following states depend heavily on this source of energy: Idaho, Washington, Oregon, Maine, South Dakota, California, Montana, and New York.

Hydropower generation has remained relatively flat for years. The most significant constraint on expansion of U.S. hydropower generation is physical; most of the best locations for hydropower generation have already been developed. Potential does remain for some increases in hydropower generation, and capacity can be optimized by adding additional turbines and increasing efficiency at existing facilities.

Also, the amount of hydropower generation depends upon the quantity of available water. A drought can have a devastating effect on a region that depends on hydropower. In fact, this year's water availability has been a contributing factor in California's electricity supply shortages. The amount of hydropower generation depends upon the quantity of available water. A drought can have a devastating effect on a region that depends on hydropower. In fact, this year's water availability has been a contributing factor in California's electricity supply shortages.

The Federal Energy Regulatory Commission is required to incorporate mandatory conditions proposed by different state and federal resource agencies into hydropower licenses. Decision-making authority in the licensing process is diffused among a host of federal and state agencies, all of which are pursuing different statutory missions. The hydropower licensing process is prolonged, costly, and poses regulatory uncertainty. The challenge is to efficiently and effectively balance national interests in natural resource and environmental preservation with energy needs.

Recommendation:

★ The NEPD Group recognizes there is a need to reduce the time and cost of the hydropower licensing process. The NEPD Group recommends that the President encourage the Federal Energy Regulatory Commission (FERC) and direct federal resource agencies to make the licensing process more clear and efficient, while preserving environmental goals. In addition, the NEPD Group recognizes the importance of optimizing the efficiency and reliability of existing hydropower facilities, and will encourage the Administration to adopt efforts toward that end.

- Support administrative and legislative reform of the hydropower licensing process.
- Direct federal resource agencies to reach interagency agreement on conflicting mandatory license conditions before they submit their conditions to FERC for inclusion in a license.
- Encourage FERC to adopt appropriate deadlines for its own actions during the licensing process.

Natural Gas

Currently, natural gas provides about 16 percent of U.S. electricity generation. Seven states obtain over one-third of their generation from natural gas (Rhode Island, new York, Delaware, Louisiana, Texas, California, and Alaska). Perhaps more importantly, natural gas-fired electricity is projected to constitute about 90 percent of capacity additions between 1999 and 2020. The amount of natural gas used in electricity generation is projected to triple by 2020.

Ensuring the long-term availability of adequate, reasonably priced natural gas supplies is a challenge. Low gas prices in 1998 and 1999 caused the industry to scale back gas exploration and production activity. Since 2000, the North American natural gas market has remained tight due to strong demand and diminished supplies. Last year, natural gas prices quadrupled, which resulted in substantially higher prices for electricity generated with natural gas.

While the largest barriers to expanded natural gas electricity generation relate to production and pipeline constraints, there are several other barriers. Environmental regulations affect the use of gas for electricity generation. Although natural gas electric plants produce fewer emissions than coal-fired power plants, they still emit nitrogen oxides, carbon dioxide and small amounts of toxic air emissions.

Oil

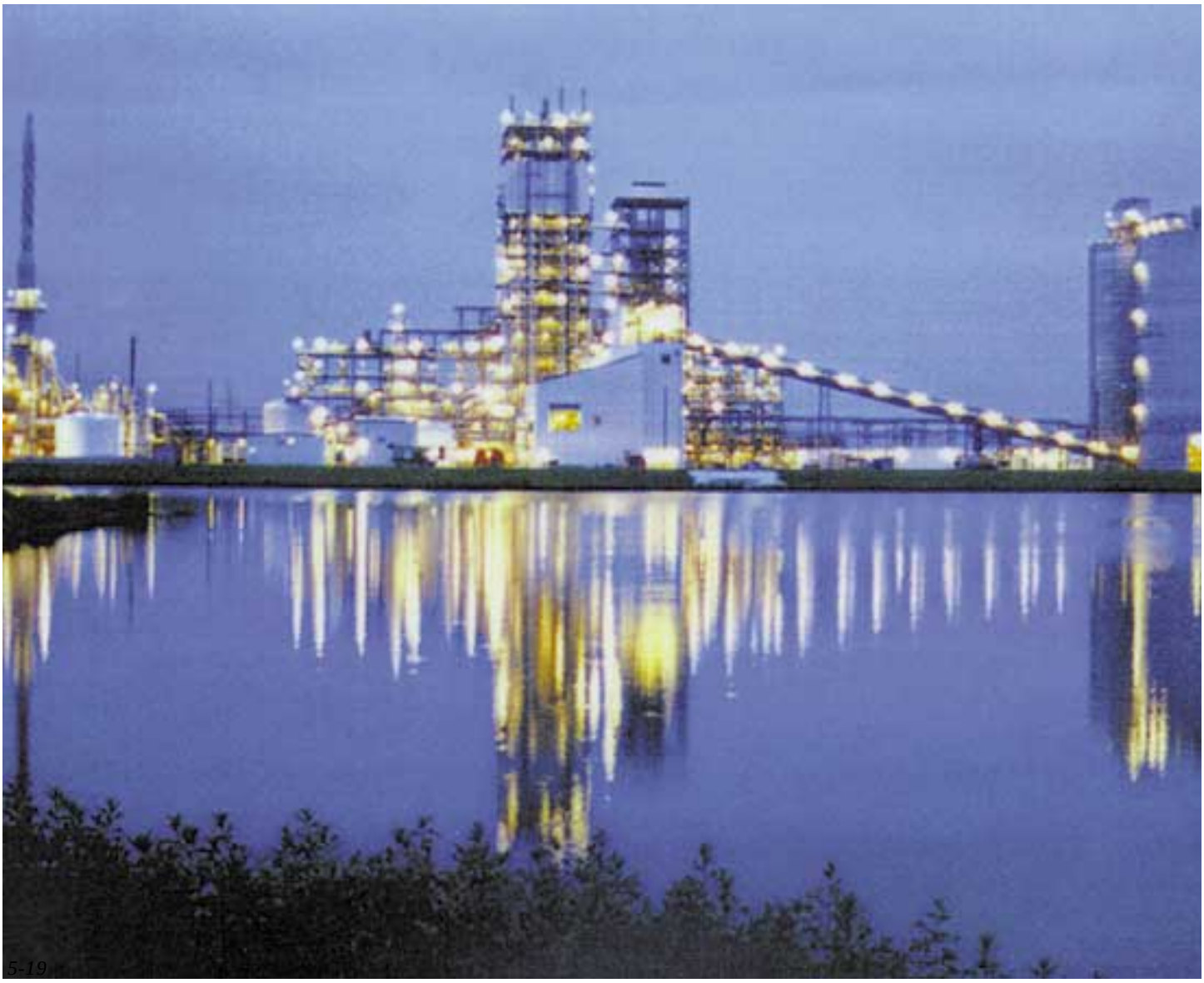
While oil fuels only about 3 percent of total U.S. electricity generation, it is the dominant source of electricity generation in Hawaii, and provides over 20 percent of the generation in Massachusetts, Connecticut, Delaware, Maine, and Florida. Over the next twenty years, market conditions are expected to reduce today's level of oil electricity generation by about 80 percent.

Renewable Energy

Hydropower is, to date, the most successful form of renewable energy. However, some forms of renewable energy generation—wind, geothermal, and biomass—have the potential to make more significant contributions in coming years, and the cost of most forms of renewable energy has declined sharply in recent years. The most important barrier to increased renewable energy production remains economic; nonhydropower renewable energy generation costs are greater than other traditional energy sources. The following chapter discusses renewable and alternative energy in greater detail.

High-tech power plants, like this combined cycle plant, are signaling a new age in electric power generation. The capability to co-produce electricity and a slate of fuels and chemicals makes the technology economically attractive to a broad range of industrial applications.

Tampa Electric Company



Summary of Recommendations
Energy for a New Century: Increasing Domestic Energy Supplies

★ The NEPD Group recommends that the President direct the Secretaries of Energy and the Interior to promote enhanced oil and gas recovery from existing wells through new technology.

★ The NEPD Group recommends that the President direct the Secretary of Energy to improve oil and gas exploration technology through continued partnership with public and private entities.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to examine land status and lease stipulation impediments to federal oil and gas leasing, and review and modify those where opportunities exist (consistent with the law, good environmental practice, and balanced use of other resources).

- Expedite the ongoing Energy Policy and Conservation Act study of impediments to federal oil and gas exploration and development.
- Review public lands withdrawals and lease stipulations, with full public consultation, especially with the people in the region, to consider modifications where appropriate.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider economic incentives for environmentally sound offshore oil and gas development where warranted by specific circumstances: explore opportunities for royalty reductions, consistent with ensuring a fair return to the public where warranted for enhanced oil and gas recovery; for reduction of risk associated with production in frontier areas or deep gas formations; and for development of small fields that would otherwise be uneconomic.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Interior to re-examine the current federal legal and policy regime (statutes, regulations, and Executive Orders) to determine if changes are needed regarding energy-related activities and the siting of energy facilities in the coastal zone and on the Outer Continental Shelf (OCS).

★ The NEPD Group recommends that the President direct the Secretary of the Interior continue OCS oil and gas leasing and approval of exploration and development plans on predictable schedules.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider additional environmentally responsible oil and gas development, based on sound science and the best available technology, through further lease sales in the National Petroleum Reserve-Alaska. Such consideration should include areas not currently leased within the Northeast corner of the Reserve.

★ The NEPD Group recommends that the President direct the Secretary of the Interior work with Congress to authorize exploration and, if resources are discovered, development of the 1002 Area of ANWR. Congress should require the use of the best available technology and should require that activities will result in no significant adverse impact to the surrounding environment.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress and the State of Alaska to put in place the most expeditious process for renewal of the Trans-Alaska Pipeline System rights-of-way to ensure that Alaskan oil continues to flow uninterrupted to the West Coast of the United States.

★ The NEPD Group recommends that the President direct the Secretary of Energy to propose comprehensive electricity legislation that promotes competition, protects consumers, enhances reliability, promotes renewable energy, improves efficiency repeals the Public Utility Holding Company Act, and reforms the Public Utility Regulatory Policies Act.

★ The NEPD Group recommends that the President encourage FERC to use its existing statutory authority to promote competition and encourage investment in transmission facilities.

★ The NEPD Group recognizes the importance of looking to technology to help us meet the goals of increasing electricity generation while protecting our environment. To that end, the NEPD Group recommends that the President direct the Department of Energy to continue to develop advanced clean coal technology by:

- Investing $2 billion over 10 years to fund research in clean coal technologies.
- Supporting a permanent extension of the existing research and development tax credit.
- Directing federal agencies to explore regulatory approaches that will encourage advancements in environmental technology.

★ The NEPD Group recommends that the President direct federal agencies to provide greater regulatory certainty relating to coal electricity generation through clear policies that are easily applied to business decisions.

★ The NEPD Group recommends that the President support the expansion of nuclear energy in the United States as a major component of our national energy policy. Following are specific components of the recommendation:

- Encourage the Nuclear Regulatory Commission (NRC) to ensure that safety and environmental protection are high priorities as they prepare to evaluate and expedite applications for licensing new advanced-technology nuclear reactors.
- Encourage the NRC to facilitate efforts by utilities to expand nuclear energy generation in the United States by uprating existing nuclear plants safely.
- Encourage the NRC to relicense existing nuclear plants that meet or exceed safety standards.
- Direct the Secretary of Energy and the Administrator of the Environmental Protection Agency to assess the potential of nuclear energy to improve air quality.
- Increase resources as necessary for nuclear safety enforcement in light of the potential increase in generation.
- Use the best science to provide a deep geologic repository for nuclear waste.
- Support legislation clarifying that qualified funds set aside by plant owners for eventual decommissioning will not be taxed as part of the transaction.
- Support legislation to extend the Price–Anderson Act.

★ The NEPD Group recommends that, in the context of developing advanced nuclear fuel cycles and next generation technologies for nuclear energy, the United States should reexamine its policies to allow for research, development and deployment of fuel conditioning methods (such as pyroprocessing) that reduce waste streams and enhance proliferation resistance. In doing so, the United States will continue to discourage the accumulation of separated plutonium, worldwide.

★ The United States should also consider technologies (in collaboration with international partners with highly developed fuel cycles and a record of close cooperation) to develop reprocessing and fuel treatment technologies that are cleaner, more efficient, less waste-intensive, and more proliferation-resistant.

★ The NEPD Group recognizes there is a need to reduce the time and cost of the hydropower licensing process. The NEPD Group recommends that the President encourage the Federal Energy Regulatory Commission (FERC) and direct federal resource agencies to make the licensing process more clear and efficient, while preserving environmental goals. In addition, the NEPD Group recognizes the importance of optimizing the efficiency and reliability of existing hydropower facilities and will encourage the Administration to adopt efforts toward that end.

- Support administrative and legislative reform of the hydropower licensing process.
- Direct federal resource agencies to reach interagency agreement on conflicting mandatory license conditions before they submit their conditions to FERC for inclusion in a license.
- Encourage FERC to adopt appropriate deadlines for its own actions during the licensing process.

Nature's Power

Increasing America's Use of Renewable and Alternative Energy

A sound national energy policy should encourage a clean and diverse portfolio of domestic energy supplies. Such diversity helps to ensure that future generations of Americans will have access to the energy they need.

Renewable energy can help provide for our future needs by harnessing abundant, naturally occurring sources of energy, such as the sun, the wind, geothermal heat, and biomass. Effectively harnessing these renewable resources requires careful planning and advanced technology. Through improved technology, we can ensure that America will lead the world in the development of clean, natural, renewable and alternative energy supplies.

Renewable and alternative energy supplies not only help diversify our energy portfolio; they do so with few adverse environmental impacts. While the current contribution of renewable and alternative energy resources to America's total electricity supply is relatively small—only 9 percent—the renewable and alternative energy sectors are among the fastest growing in the United States. Non-hydropower only account for 2 percent of our electricity needs. However, electricity generation from non-hydropower renewable energy grew by nearly 30 percent in the 1990s. Continued growth of renewable energy will continue to be important in delivering larger supplies of clean, domestic power for America's growing economy.

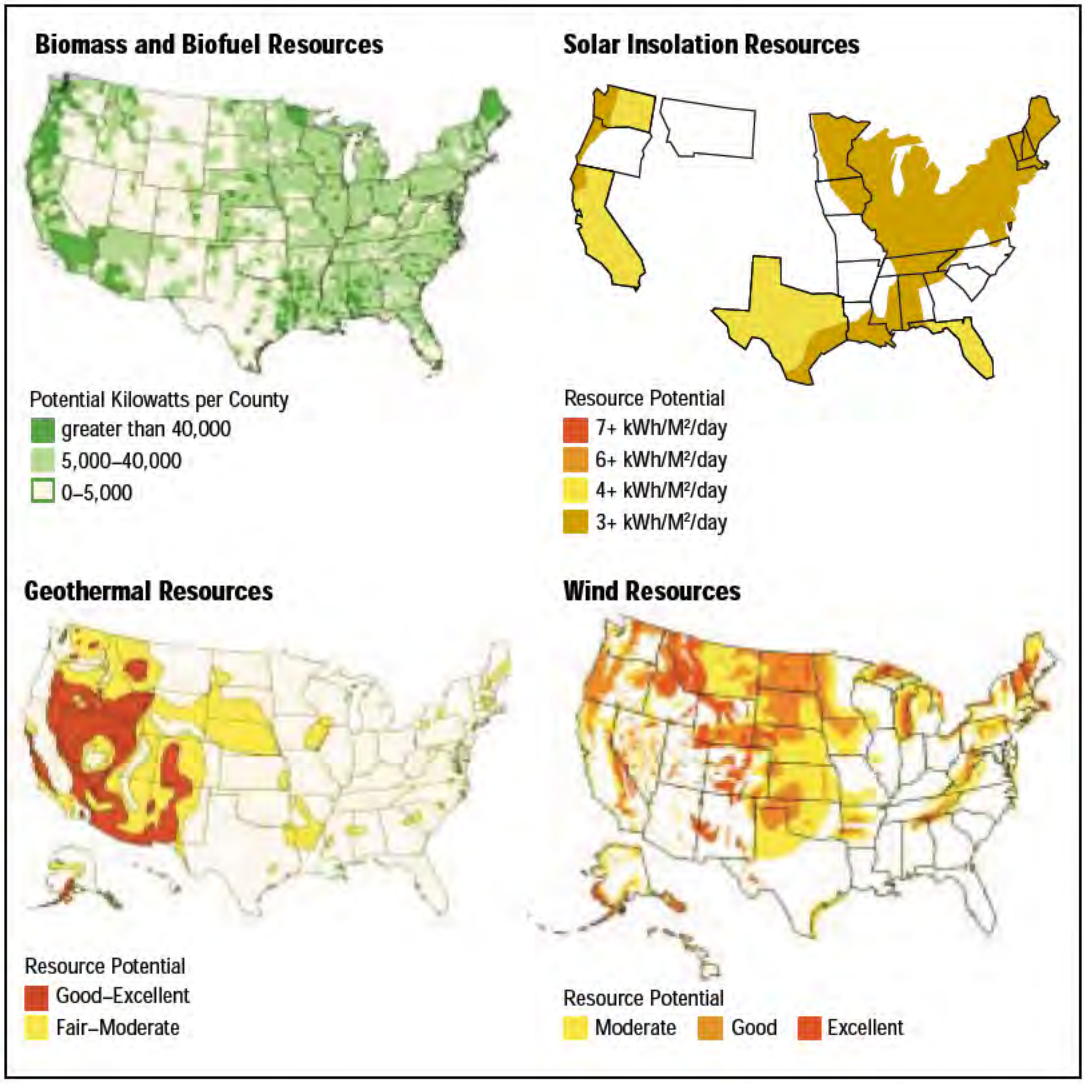
Renewable energy resources tap naturally occurring flows of energy to produce electricity, fuel, heat, or a combination of these energy types. One type of renewable energy, hydropower, has long provided a significant contribution to the U.S. energy supply and today is competitive with other forms of conventional electricity. However, there is limited growth potential for hydropower. Non-hydropower renewable energy is generated from four sources: biomass, geothermal, wind, and solar (Figure 6-1). The United States has significant potential for renewable resource development. These nondepletable sources of energy are domestically abundant and often have less impact on the environment than conventional sources. They can provide a reliable source of energy at a stable price, and they can also generate income for farmers, landowners, and others who harness them.



Renewable hydropower has long provided a significant contribution to the U.S. energy supply. Today, hydropower is competitive with other forms of conventionally generated electricity.



Figure 6-1
U.S. Resource Potential for Renewable Energy



Almost every state has the potential for wind energy and for biomass and biofuel production. The Southwest has the greatest potential for solar energy, and geothermal energy resources are most abundant in the West.

Source: U.S. Department of Energy, National Renewable Energy Laboratory.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to re-evaluate access limitations to federal lands in order to increase renewable-energy production, such as biomass, wind, geothermal, and solar.

Alternative energy includes: alternative fuels that are transportation fuels other than gasoline and diesel, even when the type of energy, such as natural gas, is traditional; the use of traditional energy sources, such as natural gas, in untraditional ways, such as for distributed energy at the point of use through microturbines or fuel cells; and future energy sources, such as hydrogen and fusion.

Both renewable and alternative energy resources can be produced centrally or on a distributed basis near their point of use. Providing electricity, light, heat, or mechanical energy at the point of use diminishes the

need for some transmission lines and pipe lines, reducing associated energy delivery losses and increasing energy efficiency. Dis tributed energy resources may be renew able resources, such as biomass cogenera tion in the lumber and paper industry or rooftop solar photovoltaic systems on homes, or they may be alternative uses of traditional energy, such as natural gas microturbines.

Recommendations:

★ The NEPD Group supports the increase of $39.2 million in the FY 2002 budget amendment for the Department of Energy's Energy Supply account that would provide increased support for research and development of renewable energy resources.

★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic perfor mance of renewable energy and alternative energy research and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.

Microturbines

Microturbines are small combustion turbines approximately the size of a refrigerator with outputs of 25 to 500 kilowatts. Microturbines can be used to power a home or small business. This technology has evolved largely from automotive and truck turbochargers, auxiliary power units for airplanes, and small jet engines.

Compared to other technologies for small-scale power generation, microturbines offer a number of significant advantages, including a small number of moving parts; compact size; lightweight, optimal effi ciency; lower emissions and electricity costs; and opportunities to use waste fuels. For these reasons, microturbines could easily capture a significant share of the distributed generation market.

Renewable Energy Technologies

Biomass

Biomass is organic matter that can be used to provide heat, make fuel, and gener ate electricity. Wood, the largest source of biomass, has been used to provide heat for thousands of years. Many other types of biomass are also used as an energy source, such as plants, residue from agriculture or forestry, and the organic component of mu nicipal and industrial wastes. Landfill gas is also considered a biomass source. Biomass resources can be replenished through culti- vation of what are known as energy crops, such as fast-growing trees and grasses.

Unlike other renewable energy sources, biomass can be converted directly into liquid fuels, called biofuels, to meet our transportation needs. The two most com mon biofuels are ethanol and biodiesel. Ethanol is made by fermenting any biomass that is rich in carbohydrates, such as corn. It is mostly used as a fuel additive to reduce a vehicle's emissions. Biodiesel is made us ing vegetable oils, animal fats, algae, or even recycled cooking greases. It can be used as a diesel additive to reduce emissions or in its pure form to fuel a vehicle. Beyond en ergy benefits, development of biomass ben efits rural economies that produce crops used for biomass, particularly ethanol and biomass electricity generation.



Biomass, like corn, that is rich in carbohydrates can be converted directly into biofuels to meet our transportation needs. The biofuel ethanol is mostly used as a fuel additive to reduce vehicles' smog-causing emissions. In June 1992, the Greater Peoria Mass Transit District began operating fourteen ethanol-powered buses along regular city routes.
U.S. Department of Energy

Biomass is also used to generate electricity. This is accomplished through the direct combustion of wood, municipal solid waste, and other organic materials; co-firing with coal in high efficiency boilers; or combustion of biomass that has been chemically converted into fuel oil. In the lumber and paper industries, wood scraps are sometimes directly fed into boilers to produce steam for their manufacturing processes or to heat their buildings. For that reason, renewable energy offers a particular advantage to the lumber and paper industry, and many analysts project the industry may soon become a net seller of electricity. Co-firing coal power plants with biomass has environmental benefits, since co firing can significantly reduce emissions. Biomass accounts for 76 percent of renewable electricity generation and 1.6 percent of total U.S. electricity supply.

Even gas for generating electricity can be produced from biomass. Gasification systems use high temperatures to convert biomass into a gas that is used to fuel a turbine. The decay of biomass in landfills also produces methane, a gas that can be captured and burned in a boiler to produce steam for electricity generation or for industrial processes. Using methane emissions increases electricity supplies, reduces pollution from landfills and reduces greenhouse gas emissions. The technologies to collect and use landfill methane to generate electricity are already in the market. However, they have not been successfully integrated at present due to the perceived higher risk of new technologies.

The Geysers in northern California is the world's largest producer of renewable geothermal power. The dry-steam field has successfully produced power since the early 1960s, when Pacific Gas & Electric installed the first 11-megawatt plant. Today, nearly 2,000 megawatts are on line – enough energy to supply the electricity needs of San Francisco and Oakland.
Pacific Gas & Electric



Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Treasury, to work with Congress on legislation to expand the section 29 tax credit to make it available for new landfill methane projects. The credit could be tiered, depending on whether a landfill is already required by federal law to collect and flare its methane emissions due to local air pollution concerns.

Geothermal

Geothermal energy is the use of steam and hot water generated by heat from the Earth to perform work. Some geothermal power plants use steam or hot water from a natural underground reservoir to power a generator. Others use hot water to provide direct heat for residential and other buildings, and for other applications.

The most readily accessible resources for geothermal power generation in the United States are located in the West, Alaska, and Hawaii. A wide array of high technology geological, geochemical, and geophysical techniques are used to locate geothermal resources. In large measure, the technology for developing these resources has been adapted from the oil industry. Improvements in drill bits, drilling techniques, advanced instruments, and other technological advances have made energy production from geothermal resources increasingly efficient.

Geothermal accounts for 17 percent of renewable electricity generation and 0.3 percent of total U.S. electricity supply. However, the net installed capacity of U.S. geothermal power plants has increased significantly, from 500 MW in 1973 to 2,800 MW today.

Hot water near the surface of the Earth can also be used directly for heat. These direct-use applications include heat

ing buildings, growing plants in green houses, drying crops, heating water at fish farms, and several industrial processes, such as pasteurizing milk.

In addition, individual homeowners, farmers, and businesses can tap into geo thermal energy through geothermal heat pumps to heat and cool buildings. A geo thermal heat pump system consists of a heat pump, an air delivery system, a heat exchanger, and a system of pipes buried in the shallow ground near the building. In the winter, a heat pump removes heat from the heat exchanger and pumps that heat into the indoor air delivery system. In the sum mer, the process is reversed, and the heat pump moves heat from the indoor air into the heat exchanger. The heat removed from the indoor air during the summer can also be used to provide a free source of hot water. Geothermal heat pumps can be used almost anywhere in the United States, and can sig nificantly increase system efficiencies.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Interior to determine ways to reduce the delays in geothermal lease process ing as part of the permitting review process.

Wind Energy

Wind energy has been used since at least 200 B.C. for grinding grain and pump ing water. By 1900, windmills were used on farms and ranches in the United States to pump water and, eventually, to produce electricity. Windmills developed into mod ern-day wind turbines.

Wind turbines are used for several ap plications. Wind power uses the naturally occurring energy of the wind for practical purposes like generating electricity, charg ing batteries, or pumping water. Large, modern wind turbines operate together in wind farms to produce electricity for utili ties. Small turbines are used by homeowners, farmers, and remote villages to help meet localized energy needs.

Wind turbines capture energy by using propeller-like blades that are mounted on a rotor. These blades are placed on top of high towers, in order to take advantage of the stronger winds at 100 feet or more above the ground. The wind causes the pro pellers to turn, which then turn the attached shaft to generate electricity. Wind can be used as a stand-alone source of energy or in conjunction with other renewable energy systems. Wind and natural gas hybrid sys tems are a promising approach that offers clean power to consumers.

Wind energy accounts for 6 percent of renewable electricity generation and 0.1 percent of total electricity supply. However, advances by research labs, universities, utilities, and wind energy developers have helped cut wind energy's costs by more than 80 percent during the last twenty years. The industry is poised for growth. In some parts of the country, electricity from wind power can be produced at prices that are comparable to other conventional en ergy technologies. The United States has many areas with abundant wind energy po tential, namely in the West, the Great Plains and New England.



In 1996, the National Association of Home Builders constructed advanced townhouses featuring standing-seam roofs and other energy efficient materials and systems. The townhouse on the right differs from the others in that it has an integrated photovoltaic standing-seam roof that also produces electricity.
Tim Ellison, Energy Conversion Devices

Solar

Sunlight, or solar energy, can be used to generate electricity; heat water; and heat, cool, and light buildings. Photovoltaic (so lar cell) systems use semiconductor materi als similar to those used in computer chips to capture the energy in sunlight and to convert it directly into electricity. Photovol taic cells have been used in everything from

the solar cells in calculators to the space station Freedom.

Another technology for harnessing the sun's energy is a concentrating solar power system, which uses the sun's heat to gener ate electricity. The sunlight is collected and focused with mirrors to create a high inten sity heat source that in turn can be used to generate electricity through a steam turbine or a heat engine.

Solar hot water systems use the sun to heat water for domestic or industrial use. Many large commercial buildings also use solar collectors for heat. A solar ventilation system can be used in cold climates to pre heat air as it enters a building. The heat from a solar collector can even be used to provide energy for cooling a building.

Some architects are using careful de sign and new optical materials to use sun light to reduce the need for traditional light ing and to cut down on heating and cooling costs. For example, materials that absorb and store the sun's heat can be built into the sunlit floors and walls. The floors and walls will store heat during the day and slowly re lease heat at night.

While solar energy technologies have undergone technological and cost improve ments and are well established in high value markets like remote power, satellites, communications, and navigational aids, continued research is needed to reduce costs and improve performance. Solar en ergy accounts for 1 percent of renewable electricity generation and 0.02 percent of total U.S. electricity supply.

Alternative Energy

Alternative Transportation Fuels

Alternative fuels are any transporta tion fuels made from a nontraditional source, including ethanol, biodiesel, and other biofuels. These can be made from biomass resources, including liquid fuels (e.g., ethanol, methanol, biodiesel) and gas eous fuels (e.g., hydrogen and methane). Biofuels are primarily used to fuel vehicles, but can also fuel engines or fuel cells for electricity generation. Alternative fuels also

Recommendations:

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to develop a new renewable energy partnership program to help companies more easily buy renewable energy, as well as receive recognition for the environmental benefits of their purchase, and help consumers by promoting consumer choice programs that increase their knowledge about the environmental benefits of purchasing renewable energy.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to extend and expand tax credits for electricity produced using renewable technology, such as wind and biomass. The President's budget request extends the present 1.7 cents per kilowatt hour tax credit for electricity produced from wind and biomass; expands eligible biomass sources to include forest-related sources, agricultural sources, and certain urban sources; and allows a credit for electricity produced from biomass co-fired with coal.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to provide a new 15 percent tax credit for residential solar energy property, up to a maximum credit of $2,000.

★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to work with Congress on legislation to use an estimated $1.2 billion of bid bonuses from the environmentally responsible leasing of ANWR for funding research into alternative and renewable energy resources, including wind, solar, geothermal, and biomass.

Alternative Fuel Vehicles

Alternative fuel vehicles (AFVs) can run on methanol, ethanol, compressed natural gas, liquefied natural gas, propane, hydrogen, electricity, biodiesel, and natural gas. Today, more than 450,000 alternative vehicles are operating in the United States. Some of the barriers to using AFVs include:

Cost—For example, a Ford Crown Victoria that runs on compressed natural gas costs about $4,000 more than its gasoline counterpart.

Refueling Infrastructure—Refueling infrastructure is limited, which can make refueling inconvenient and travel options difficult.

Travel Distance—Ability to travel a long distance on a single volume of fuel. Al ternative fuels have an energy content lower than that of gasoline, which means that AFVs cannot travel as far as traditional vehicles on a single tank of fuel.

In the short term, natural gas and propane offer the greatest potential for market growth, especially in niche markets where lower fuel costs make them attractive, such as transit buses, school buses, shuttles, and other heavy-duty vehicles. Ethanol vehicles offer tremendous potential if ethanol production can be expanded. Electric vehicles could reach large numbers in the future if technology breakthroughs help bring costs down and increase driving distance. Fuel cell vehicles operating on com pressed hydrogen offer long-term potential. Compressed natural gas offers a distribu tion stepping-stone to a hydrogen-refueling infrastructure.

include traditional energy sources, such as natural gas and liquid propane that are tra ditionally not used as a transportation fuel.

Currently, there are approximately 450,000 alternative fuel vehicles in the United States, and more than 1.5 million flexible-fuel vehicles that can use gasoline or a mixture of ethanol and gasoline. Etha nol is made by converting the carbohydrate portion of biomass into sugar, which is then converted into ethanol through a fermenta tion process. Ethanol is the most widely used biofuel, and its production has in creased sharply since 1980, rising from 200 million gallons a year to 1.9 billion gallons. Today, many states are considering phasing out the use of MTBE (methyl tertiary butyl ether), an oxygenate additive for gasoline. If they do so, that will likely spur greater re liance on ethanol.

Each year, approximately 65 percent of the oil consumed in the United States is used for transportation. As a result, vehicle emissions have become the leading source of U.S. air pollution. However, recent ad vances in fuels and vehicle design are help ing increase fuel efficiency and reduce toxic substances discharged into the air.

Changes in the composition of trans portation fuels, such as gasoline and diesel fuels, are one way to improve vehicle per formance while reducing emissions and lowering oil consumption. Reformulated gasoline contains fuel additives such as ethanol to increase oxygen content, which reduces harmful emissions such as carbon monoxide. Low-sulfur gasoline reduces sul fur oxide emissions. New diesel fuels, some of which have lower sulfur contents or are produced from clean-burning natural gas, can help vehicles with diesel engines achieve lower emissions.

In addition to advanced transportation fuels, alternative fuels are being developed, such as biodiesel, electricity, ethanol, hydro gen, methanol, natural gas, and propane. These alternative fuels not only reduce de pendence on petroleum transportation fu els. They reduce or entirely eliminate harm ful emissions as well. With the exception of natural gas and propane, these fuels also have the potential of being generated from renewable resources, such as ethanol from corn. The federal government has promoted development of alternative fuels for many years and this program has helped to reduce U.S. reliance on oil-based fuels.

The evolution toward more efficient,

environmentally friendly transportation fu els has been mirrored by improvements in vehicle design, components, and materials. Alternative fuel vehicles, which can either switch between two fuels or run on a mix ture of two fuels such as gasoline and etha nol, are now available. Recent developments in both alternative fuel vehicles and petro leum-based vehicles, such as advances in engines, drive trains, and emission-control technologies, may double or triple the effi ciency of current vehicles. Some of these new technologies include hybrid electric ve hicles, which combine an engine with an electric motor, and fuel cells, which produce electricity by converting a fuel, generally hy drogen and oxygen, into water.

A number of issues drive the research and marketability of advanced alternative fuel vehicles and petroleum-based vehicles in the United States. The goal of reducing U.S. dependence on imported oil, combined with the link between vehicle emissions and air pollution, have prompted the develop ment of emissions and fuel economy stan dards for car manufacturers. In addition, federal, state, and local governments have enacted regulations, laws, and incentives de signed to reduce the number of vehicle miles traveled and to encourage businesses and individuals to purchase alternative fuel vehicles.

The success of the federal alternative fuels program has been limited, however. The current program focuses on mandating certain fleet operators to purchase alterna tive fueled vehicles. The hope was that this vehicle purchase mandate would lead to ex panded use of alternative fuels. That expec tation has not been realized, since most fleet operators purchase dual-fueled vehicles that operate on petroleum motor fuels. The Clean Air Act required the use of oxygen ates, such as MTBE (methyl tertiary butyl ether) and ethanol in fuel. These oxygenates account for 92 percent of alternative fuel use. Reforms to the federal alternative fuels program could promote alternative fuels use instead of mandating purchase of vehicles that ultimately run on petroleum fuels.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Treasury to work with Congress to continue the ethanol excise tax exemption.

Distributed Energy

Untapped opportunities for reducing energy demand loads could be realized by better integrating electricity supply systems and customers. Improved integration can produce a variety of benefits for tight en ergy markets, including reducing peak de mand loads, bypassing congested areas of transmission by placing new generating ca pacity closer to the consumer, and thus achieving greater overall system efficien cies.

Current electricity load management efforts are typically limited to cutting off in terruptible or nonfirm customers, appeals to the public to conserve, and brownouts. Some utilities are incorporating current generation metering, sensor, and control technologies to take the next step: selective reduction of individual energy-using appli ances. In some areas, residents can reduce their monthly bills by allowing the utility to electronically turn off selected appliances, such as water heaters, on a rotating basis. If this option is well managed, consumers are unaware of the temporary loss service, and critical systems continue to run unimpeded. Advanced integrated supply-and-demand load management controls also allow for widespread “demand auctions,” in which consumers can decide which energy ser vices to forego on which days.

Distributed energy resources describe a variety of smaller electricity-generating options well suited for placement in homes, offices, and factories, or near these facili ties. Distributed energy systems have the distinct advantage of being brought on line faster than new central power plants. While natural gas microturbines and solar roof panels are the most familiar types of distrib uted energy, other distributed energy re sources include: combined heat and power, stationary fuel cells, generation of

bioenergy from landfill methane recovery, and small wind systems. Photovoltaic solar distributed energy is a particularly valuable energy generation source during times of peak use of power.

Efficiency gains from distributed en ergy come from three sources. First, trans mission and distribution line losses (about 5 percent) are reduced because the energy is generally used near the source. Second, the co-location with consumption makes it more feasible to use waste heat, displacing otherwise needed natural gas or electricity for heating purposes. And, third, the co-lo cation with consumption allows for the in tegration of on-site energy efficiency and generating capabilities. For example, in the residential market, distributed energy appli cations can make possible the concept of the "net zero energy home," in which the overall level of energy produced at the home equals or exceeds the amount of en ergy used in the home.

Despite these advantages, a number of impediments and competing policy ob jectives discourage the wider application of integrated electricity supply and demand solutions, many of which reflect the relative newness and lack of familiarity with these technologies.

For example, the lack of standards governing interconnection of distributed energy to the grid impedes development. The lack of standards prevents a uniformly effective means of getting excess distrib uted energy to the grid.

In addition, current air quality regula tions do not take into account the additional energy savings from many distributed en ergy technologies. Likewise, distributed en ergy systems purchased by consumers may receive different tax rates than those pur chased by traditional electricity producers.

Although distributed energy can alle viate distribution constraints, these systems often cannot be sited and permitted in a timely manner. For instance, land-use zon ing codes may not allow generating equip ment in association with residential or com mercial land uses, and building code offi cials may not know enough about solar roof systems to provide timely building permits.

As with energy efficiency equipment, load management integrating systems, both controls and distributed energy, have higher first costs associated with lower future en ergy bills.

Another barrier to development of dis tributed energy is the need for net metering, which enables consumers to install a small electricity project at their homes and sell the excess to the local utility, offsetting their purchases from the utility at other times. Net metering can lower the cost to consumers of distributed energy projects. Some consumers are reluctant to install dis tributed renewable energy resources be cause many regions do not have the regula tory framework under which consumers can sell energy back to the grid under a net metering system.

Future Energy Sources

As we look to the long-term future of alternative energy technologies, there is sig nificant promise in these technologies to meet an ever-growing portion of our nation's energy needs.

Hydrogen

In the long run, alternative energy technologies such as hydrogen show great promise. Hydrogen is the most common ele ment in the universe and can be made from water. Converting hydrogen into energy is compatible with existing energy technolo gies, such as fuel cells, engines, and com bustion turbines. The energy for extracting hydrogen could come from existing, tradi tional fuels, or it could be derived from re newable energy sources, such as solar, nuclear, and fossil, to achieve the cleanest possible energy cycle. Hydrogen can be converted into useful energy forms effi ciently and without detrimental environ mental effects. Unlike other energy sources, its production by-product is water.

In the future, hydrogen may be able to be used in furnaces and as a transportation fuel for automobiles, buses, trains, ships and airplanes. Hydrogen could also be con verted directly into electricity by fuel cells. Combustion of hydrogen with oxygen re sults in pure steam, which has many appli-



There is a significant promise in renewable technologies to meet an ever-growing portion of our nation's energy needs. Wind power has significant growth potential. The principal challenges to achieving this level of renewable energy generation are cost and market acceptance of renewable power technologies.
U.S. Department of Energy, National Renewable Energy Laboratory

cations in industrial processes and space heating. Moreover, hydrogen is an important industrial gas and raw material in numerous industries, such as computer, metallurgical, chemical, pharmaceutical, fertilizer and food industries.

An energy infrastructure that relies on hydrogen could enable much greater use of distributed energy systems. These systems are small, modular electricity generators that can be placed right where they are needed for heating, cooling, and powering offices, factories, and residences. Hydrogen fuel cells are a promising type of distributed energy system that can provide the exacting reliability needed for the high-tech industry.

Fuel cells can produce electricity and heat from hydrogen, natural gas, and petroleum fuels, and fuel gases derived from coal and biomass. What makes fuel cells unique is that they can use fuels without combustion, simply by chemical reactions, making them extremely clean and efficient.

Fuel cells were developed by the National Aeronautics and Space Administration to generate electricity, heat, and water in space vehicles. The first-generation fuel cells for stationary power applications entered the commercial market in 1995. This type of fuel cell is used to generate very high-quality electricity and heat with negligible emissions in commercial and industrial settings. It is most likely to be used in cases where users are willing to pay a premium for cleaner, more reliable power than is available from the commercial grid.

The second generation of stationary fuel cells is currently in the demonstration phase, including a combined fuel cell–turbine hybrid. These fuel cells are expected to be more efficient and cost less when used in similar distributed energy systems. Smaller fuel cells for residential units are also being developed, and some are in the demonstration phase.

Despite technical progress, high costs remain the main deterrent to widespread fuel cell use. Significant cost reductions must be achieved before fuel cells will be competitive with internal combustion engines, and the size and weight of fuel cell systems must be reduced even more to accommodate vehicle packaging requirements.

The primary challenge to using more hydrogen in our energy systems is the cost of producing, storing, and transporting it. A serious challenge confronting a move toward distributed energy is the transition away from centralized energy systems of supply and production. These challenges are not expected to be resolved overnight, but progress made in the last few years has already far surpassed the expectations of just a decade ago.

A significant amount of promising research and development has already been completed. The automobile industry is aggressively exploring the fuel cell as the future of the industry. Moreover, a new first generation class of distributed energy technologies are already hitting the market.

Fusion

Fusion—the energy source of the sun—has the long-range potential to serve as an abundant and clean source of energy. The basic fuels, deuterium (a heavy form of hydrogen) and lithium, are abundantly available to all nations for thousands of years. There are no emissions from fusion, and the radioactive wastes from fusion are short lived, only requiring burial and oversight for about 100 years. In addition, there is no risk of a melt-down accident because only a small amount of fuel is present in the system at any time. Finally, there is little risk of nuclear proliferation because special nuclear materials, such as uranium and plutonium, are not required for fusion energy. Fusion systems could power an energy supply chain based on hydrogen and fuel cells, as well as provide electricity directly.

Although still in its early stages of development, fusion research has made some advances. In the early 1970s, fusion research achieved the milestone of producing 1/10 of one watt of fusion power, for 1/100 of a second. Today the energy produced from fusion is 10 billion times greater, and has been demonstrated in the laboratory at powers over 10 million watts in the range of a second.

Internationally, an effort is underway in Europe, Japan, and Russia to develop plans for constructing a large-scale fusion science and engineering test facility. This test facility may someday be capable of steady operation with fusion power in the range of hundreds of megawatts.

Both hydrogen and fusion must make significant progress before they can be come viable sources of energy. However, the technological advances experienced over the last decade and the advances yet to come will hopefully transform the en ergy sources of the distant future.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to develop next-generation technology—including hydrogen and fusion.

- Develop an education campaign that communicates the benefits of alternative forms of energy, including hydrogen and fusion.
- Focus research and development efforts on integrating current pro grams regarding hydrogen, fuel cells, and distributed energy.

Current Markets for Renewable and Alternative Energy

Advances in Technology

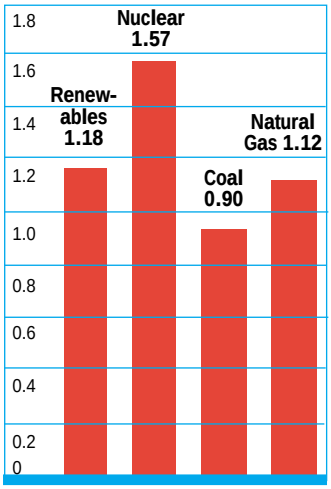
Non-hydropower renewable energy accounts for about 4 percent of current U.S. energy production, divided evenly be tween electricity generation and transpor tation fuels such as ethanol. Between 1990 and 1999, renewable energy generation grew by 29 percent, and renewable energy is projected to continue to grow (Figure 6-1). Renewable fuel consumption, includ ing ethanol for gasoline blending, is pro jected to grow at an average rate of 1.1 per cent a year through 2020. In 2020, 55 per cent of renewables are projected to be used for electricity generation and the rest for dispersed heating, industrial uses, and fuel blending.

The success of renewables is, in part, the result of over twenty years of research, development, and demonstration conducted by the public and private sectors. This work has dramatically improved these technolo gies and has reduced their costs by as much as 90 percent. For example:

- The Department of Energy (DOE), the National Renewable Energy Laboratory (NREL), and Alstom Energy Systems jointly created Advanced Direct-Contact Condens ers, which improve the efficiency and gener ating capacity of electric power plants by providing the best surface area for condens ing spent steam. This technological ad vance, tested in geothermal applications in California, can improve the efficiency of electricity production by 5 percent and capacity by 17 percent.
- United Solar Systems in Michigan pioneered the first commercial use of solar photovoltics as a building material. The triple-junction, thin-film technology is now sold as flexible solar panels, solar shingles for building roofs, and a peel-and-stick-on variety for standing seam metal roofs. United Solar is now building a larger manu facturing plant in Michigan that is five times the size of its existing manufacturing facil ity. DOE collaborates with United Solar on research and development helping over come hurdles in manufacturing. As a result, United Solar is able to provide unique solar electric products using a unique roll-to-roll manufacturing process.
- In partnership with DOE, NREL, Battelle Lab, Burlington Electric and others, Future Energy Resources Corporation of Norcross, Georgia, was able to build, test, and operate the world's first biomass gasifi cation system. The McNeil Plant, located in Burlington, Vermont, gasifies rather than combusts wood chips to power a gas boiler. The technology has shown itself to be com mercially viable, and is being considered worldwide by industries as a way of upgrad ing existing inefficient and aging boilers.

Improved renewable and alternative energy technologies are becoming increas ingly attractive to a number of energy com panies seeking to build new business oppor tunities for the future (Figure 6-3). Follow ing are a few examples:

Figure 6-1
Increases in U.S. Energy Production: 1990–1999



During the last decade, renewable energy sources contributed substantially to the growth in U.S. energy production, outpacing all fuel sources except for nuclear energy.

Source: U.S. Department of Energy, Energy Information Administration.

Table 6-2

Electricity Generated by Renewable Energy Sources: 1999

	Solar	Wind	Geothermal	Biomass	Hydropower
Current net summer capacity (MW)	350	2,600	2,870	6,170	79,130
Annual generation (millions of kWh)	940	4,460	13,070	36,570	312,000
Expected growth in generation (%)	PV: 19.3 Thermal: 21	5.3	3.3	3.0	-0.1
Cost (cents/kWh)	20	4–6	5–8	6–20	2–6

Renewable energy has become a significant source of electric power in the United States.

Note: Capacity, generation, and growth data do not include off-grid electricity, thermal, or other nonelectricity energy production, municipal solid waste, or methane from landfills.

Sources: U.S. Department of Energy, Energy Information Administration and Office of Power Technologies.

• FPL Group announced in January 2001 the construction of two major wind farms: a 300 MW facility on the Washington–Oregon border, and a 25.5 MW facility in Wisconsin. The company now has more than 1,000 MW of wind generating capacity in operation or under construction in seven states.

• CalEnergy Company has made renewable and alternative energy generation a central focus of its power portfolio. The company operates 1,300 MW of geothermal, natural gas, hydropower, and other power facilities in the U.S. and abroad, with another 750 MW currently under construction.

• General Motors, Ford, DaimlerChrysler, Texaco, BP/Amoco, and Shell are collectively spending between $500 million and $1 billion dollars a year on fuel cells, hydrogen storage, and infrastructure development for passenger vehicles. Ongoing bus demonstrations in the United States and Europe are expected to commercialize fuel cell power hydrogen buses in the next five years.

Because alternative and renewable energy resources can be used in so many different ways throughout the economy to produce so many combinations of energy types, their total use is often difficult to measure precisely. As of 1996, California alone had over 10 MW of installed distributed energy, a large increase in generating capacity during a period of otherwise limited growth in generation (Figure 6-3). In 1999, several types of renewable energy were used to produce electricity (Table 6-2).

On the transportation side, there are approximately 450,000 alternative fuel vehicles in the United States. Additionally, there are more than 1.5 million flexible-fuel vehicles that can use gasoline or a high mixture of ethanol and gasoline. These include the Ford Taurus, the DaimlerChrysler Caravan, and the General Motors S10 pickup. Ethanol is the most widely used biofuel, and its production is currently 1.9 billion gallons a year, representing a nearly ten-fold growth from about 200 million gallons a year in 1980.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to develop legislation to provide for a temporary income tax credit available for the purchase of new hybrid or fuel-cell vehicles.

Hybrid Electric Vehicles

Hybrid electric vehicles (HEVs) combine the internal combustion engine of a conventional engine with the battery and electric motor of an electric vehicle, resulting in twice the fuel economy of conventional vehicles. This combination offers the extended range and rapid refueling that consumers expect from a conventional vehicle, with a significant portion of the energy and environmental benefits of an electric vehicle. The practical benefits of HEVs include improved fuel economy and lower emissions compared to conventional vehicles. The car's flexibility will mean convenient use for individuals as well as businesses.

Removing Barriers to Renewable and Alternative Energy Growth

Perhaps the greatest barrier to growth of renewable energy is cost. Currently, the cost of renewable energy generation fre

quently exceeds the costs of conventional electricity generation. In recent years, though, the costs of renewable energy have declined substantially. For example, the cost of wind energy has declined by more than 80 percent over the past twenty years and is increasingly competitive with con ventional electricity generation sources. Wind, biomass, and geothermal are all in creasingly competitive with conventional electricity generation.

The ability of these technologies to meet specific market needs is another fac tor in how quickly their market share will grow. These technologies and energy sources provide multiple benefits to the en ergy producer and the consumer. For ex ample, many of these technologies are modular and can be constructed rapidly, adding an immediate source of new power in areas that otherwise might face a short fall. Distributed renewable energy re sources can enhance the reliability and quality of power.

Cogeneration uses of waste products and heat can increase profits by reducing purchased electricity costs, as well as costs for process steam and heating or cooling. Several sectors, including lumber and paper, steel, and chemical manufacturing, are ex ploring the increased use of cogeneration. With the technological development of biom ass gasification, the lumber and paper indus try could become a seller of electricity.

Recommendation:

★ The NEPD Group recommends that the President direct the Adminis trator of the Environmental Protec tion Agency to issue guidance to encourage the development of well designed combined heat and power (CHP) units that are both highly efficient and have low emissions. The goal of this guidance would be to shorten the time needed to obtain each permit, provide certainty to industry by ensuring consistent implementation across the country, and encourage the use of these cleaner, more efficient technologies.

Renewable technologies can help pro vide insurance against price volatility. In ad dition, many renewable technologies can help industry achieve compliance with the Clean Air Act and other environmental regu lations. In some cases, renewables can be more readily located in urban areas whose air quality does not meet regulatory require ments.

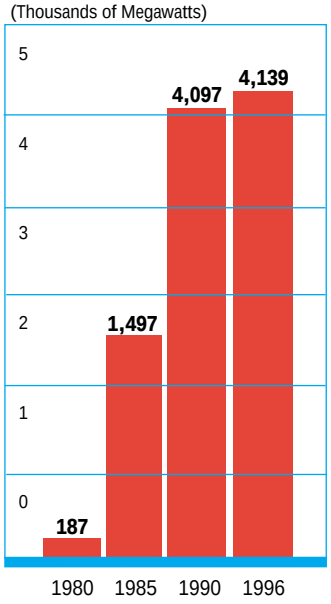
With the growth rate for non-hydro power renewable electricity generation more than doubling the expected growth in overall electricity capacity, these energy sources will play a more significant role in electricity markets in the next two decades. However, the extent to which these domes tic resources are successfully tapped will depend in large part on continued techno logical development.

For renewable and alternative energy to play a greater role in meeting our energy de mands, these sources of generation must be able to integrate into our existing distribution system. The tools that form the necessary in terface between distributed energy systems and the grid need to be less expensive, faster, more reliable, and more compact.

Promising technologies exist that will improve the transmission, storage, and reli ability of renewable energy. An example of recent technological success that will allow for increased access to all forms of energy, including renewable energy, is the high-tem perature superconducting underground power transmission cables that the Depart ment of Energy is developing in partnership with industry. These cables will allow a 300 percent increase in capacity without exca vation to lay new transmission lines. This summer, Detroit Edison is demonstrating this commercially viable high-temperature superconducting cable system in an applica tion that serves 14,000 customers.

Renewable and alternative energy technologies, such as wind energy and com bined heat and power could be significantly expanded, given today's technologies. They could be further expanded with added in vestment in technology. For example, wind energy could be developed that could be adapted to sites with lower wind speeds than is feasible today. Combined heat and

Figure 6-3
Growth in California's Renewable Energy Capacity



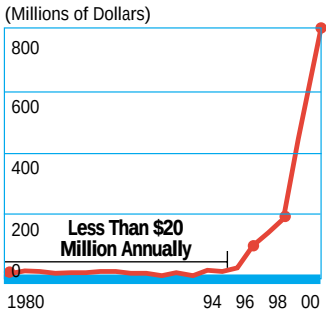
Source: U.S. Department of Energy, Energy Information Administration.



While solar energy technologies have undergone technological and cost improvements, and are well established in high value markets like remote power, satellites, communications, and navigational aids continued research is needed to reduce costs and improve performance.

U.S. Department of Energy

Figure 6-4
Investors Are Betting on Distributed Energy



In the last few years, surging venture capital investments showed strong support for distributed energy technologies.

Note: Data for 2000 are projected investments.
Source: Nth Power via the Economist, August 5, 2000.

power in buildings offers great potential for increased system efficiencies and lower costs. New developments in microturbine and fuel cell technologies are also highly promising. Performance improvements of other technologies, such as photovoltaic systems, would facilitate much wider use. In addition to technological performance, attention to several key market and regula tory constraints would accelerate the devel opment and use of renewable and alterna tive energy in the marketplace.

Because many renewable and alterna tive energy technologies do not fit into tra ditional regulatory categories, they are of ten subjected to competing regulatory re quirements or to requirements that were never designed to address them. For ex ample, much of the current Clean Air Act does not specifically address the use of new, more efficient renewable energy tech nologies. Consequently, the Act does not provide significant incentives for the devel opment of such technologies.

The lack of interconnection standards or guidelines for electricity supply and loads impedes the use of distributed energy tech nologies. As a result, developers of small re newable energy projects must negotiate in terconnection agreements on a site-by-site basis with local distribution companies that are often opposed to distributed energy projects because of the increased competi tion. Although a few states have established interconnection standards, there is no na tional standard to facilitate development of distributed energy (Figure 6-4).

New combined heat and power facili ties may face air permitting hurdles when they replace marginally dirty boilers. The Clean Air Act does not recognize the pollu tion prevention benefits of the increased ef ficiency of combined heat and power units. At the same time, these combined heat and power investments are taxed at the industry's tax rate, not at the rate they would receive if they were considered part of the utility sector for tax purposes.

In addition, modifications to permitting and siting requirements may be necessary to fa cilitate the incorporation of these technolo gies into buildings.

The infrastructure needed for increas ing the use of renewable and alternative en ergy varies considerably. In particular, the alternative fuels infrastructure lags far be hind the existing infrastructure for conven tional fuels. The lack of infrastructure for al ternative fuels is a major obstacle to con sumer acceptance of alternative fuels and the purchase of alternative fuel vehicles. It is also one of the main reasons why most al ternative fuel vehicles actually operate on petroleum fuels, such as gasoline and diesel. In addition, a considerable enlargement of ethanol production and distribution capac ity would be required to expand beyond their current base in the Midwest in order to increase use of ethanol-blended fuels.

The use of natural gas or electricity for vehicles requires enhancements to these distribution systems, such as compression stations for natural gas. While many alterna tive fuels can be shipped by pipeline, they may require separation within the pipeline to avoid mixing different energy products. Geographically dispersed renewable energy plants often face significant transmission barriers, including unfavorable grid sched ule policies and increased embedded costs.

Uncertainty regarding the tax treat ment of these technologies and energy sources can discourage long-term invest ment. Though existing tax credits provide an incentive for investing in some types of renewable energy, the limited scope of the credit and its frequent expiration discour ages investment.

Summary of Recommendations

Nature's Power: Increasing America's Use of Renewable and Alternative Energy

★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to re-evaluate access limitations to federal lands in order to increase renewable energy production, such as biomass, wind, geothermal, and solar.

★ The NEPD Group supports the increase of $39.2 million in the FY 2002 budget amendment for the Department of Energy's Energy Supply account that would provide increased support for research and development of renewable energy re sources.

★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of renewable energy and alternative energy research and development programs in light of the recommen dations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to expand the section 29 tax credit to make it available for new landfill methane projects. The credit could be tiered, depending on whether a landfill is already required by federal law to collect and flare its methane emissions due to local air pollution concerns.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to determine ways to reduce the delays in geothermal lease processing as part of the permitting review process.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to develop a new renewable energy partnership program to help companies more easily buy renewable energy, as well as receive recognition for the environmental benefits of their purchase, and help consumers by promoting consumer choice programs that increase their knowledge about the environmental benefits of purchasing renewable energy.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to extend and expand tax credits for electricity produced using wind and biomass. The President's budget request extends the present 1.7 cents per kilowatt hour tax credit for electricity produced from wind and biomass; expands eligible biomass sources to include forest-related sources, agricultural sources, and certain urban sources; and allows a credit for electricity produced from biomass co-fired with coal.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to provide a new 15 percent tax credit for residential solar energy property, up to a maximum credit of $2,000.

★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to work with Congress on legislation to use an estimated $1.2 billion of bid bonuses from the environmentally responsible leasing of ANWR for funding research into alternative and renewable energy resources, including wind, solar, geothermal, and biomass.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to continue the ethanol excise tax exemption.

★ The NEPD Group recommends that the President direct the Secretary of Energy to develop next-generation technology—including hydrogen and fusion.
• Develop an education campaign that communicates the benefits of alternative forms of energy, including hydrogen and fusion.
• Focus research and development efforts on integrating current programs regarding hydrogen, fuel cells, and distributed energy.
• Support legislation reauthorizing the Hydrogen Energy Act.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to develop legislation to provide for a temporary income tax credit available for the purchase of new hybrid or fuel-cell vehicles be tween 2002 and 2007.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to issue guidance to encourage the development of well-designed combined heat and power (CHP) units that are both highly efficient and have low emissions. The goal of this guidance would be to shorten the time needed to obtain each permit, provide certainty to industry by ensuring consistent implementa tion across the country, and encourage the use of these cleaner, more efficient tech nologies.

America's Energy Infrastructure

A Comprehensive Delivery System

One of the greatest energy challenges facing America is the need to use 21st- century technology to improve America's aging energy infrastructure. Americans need a comprehensive, long-term solution to deliver energy to industry and consumers in a reliable and safe manner.

Our energy infrastructure is comprised of many components, such as the physical network of pipes for oil and natural gas, electricity transmission lines and other means for transporting energy to consumers. This infrastructure also includes facilities that turn raw natural resources into useful energy products. The rail network, truck lines, and marine transportation are also key components of America's energy infrastructure.

The energy industry has undergone major changes in the last two decades, and more are expected. These changes affect how our energy infrastructure operates. For example, while the electricity industry was once vertically integrated, it is increasingly separated into three isolated segments: generation, transmission, and distribution.

Our energy infrastructure has failed to keep pace with the changing requirements of our energy system. Domestic refining capacity has not matched increases in demand, requiring the United States to import refined products. Natural gas pipelines have not expanded sufficiently to meet demand. The electricity transmission system is constrained by insufficient capacity. Rail capacity was significantly increased during the 1970s when rail facilities were improved to move more coal. Since then, however, few additions to the coal transportation rail network have been built.

The United States needs to modernize its energy infrastructure. One sign of a lack of an energy policy in recent years has been the failure to maintain the infrastructure needed to move energy where it is needed most.

Electricity

The electricity infrastructure includes a nationwide power grid of long-distance transmission lines that move electricity from region to region, as well as the local distribution lines that carry electricity to homes and businesses. Electricity originates at power plants, which are primarily fueled by coal, nuclear, natural gas, water and, to a lesser extent, oil. Coal, natural gas and oil powered plants require a dependable transportation infrastructure to deliver the fuels necessary for the production of electricity. A transportation network for waste disposal is also necessary for power plants that create by products.

Restructuring

The electricity industry has undergone considerable changes in the last two decades. These changes affect how our electricity infrastructure operates. Major industry restructuring has separated once vertically integrated electric utilities that supplied generation, transmission, and distribution services into distinct entities. To facilitate competition at the wholesale level, in 1996, the Federal Energy Regulatory Commission (FERC) required transmission-owning utilities to "unbundle" their transmission and power marketing functions, and provide nondiscriminatory, open access to their transmission systems by other utilities

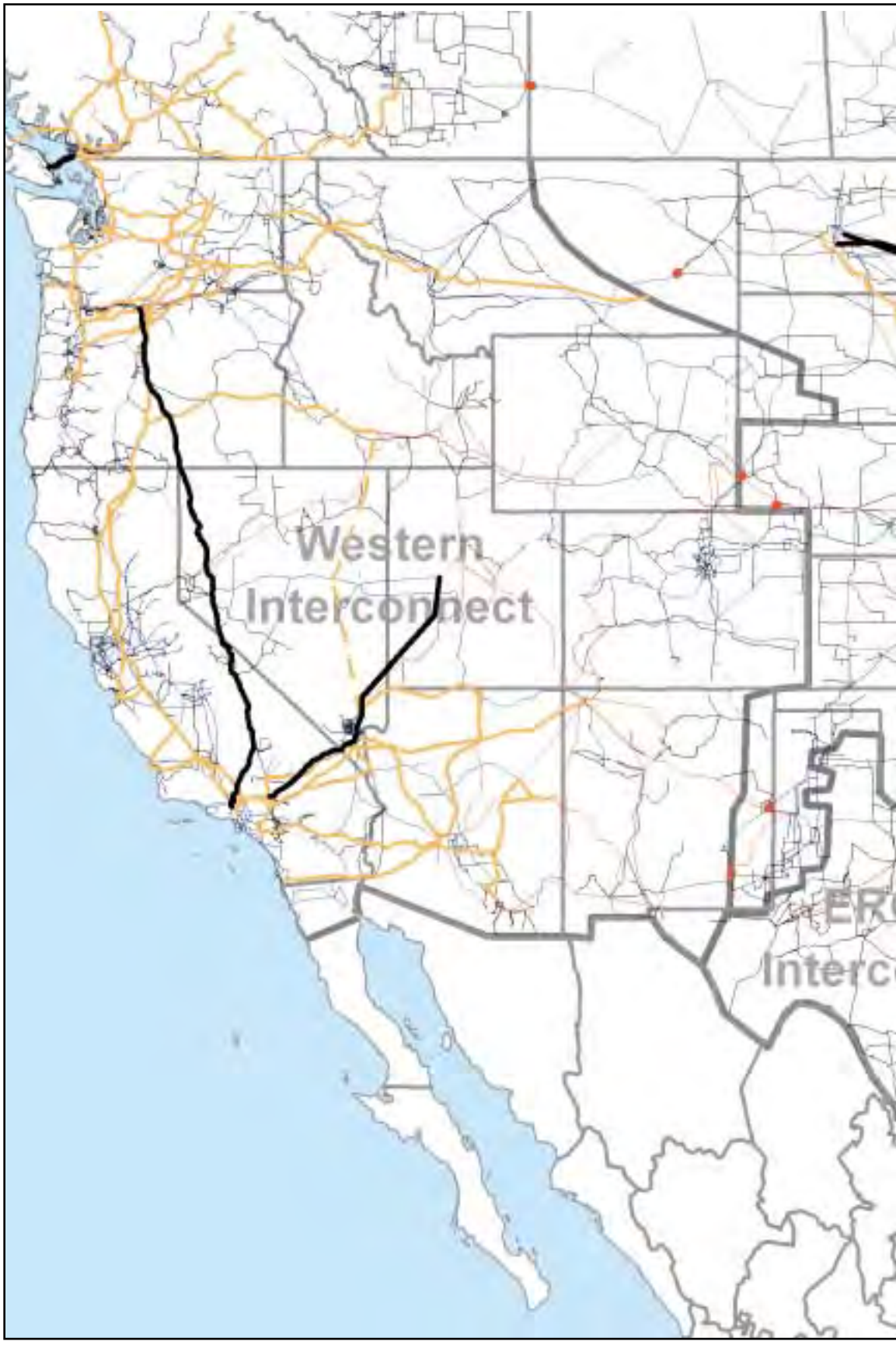
U.S. DEPARTMENT OF ENERGY



FIGURE 7-1
North American Transmission Lines

About 204,000 miles of long-distance transmission lines move power from region to region. The four integrated transmission grids serving North America are the Western Interconnection, Eastern Interconnection, Electric Reliability Council of Texas, and Province of Quebec.

Source: PA Consulting Group




Eastern
Interconnect
COT
onnect
Legend
Below 230kv
230kv - 344kv
345kv - 499kv
500kv - 734kv
735kv - 999kv
AC-DC-AC Tie
DC Line
Dashed lines indicate proposed transmission lines.
Prepared using RDI PowerMap data. Information on this map is believed to be accurate but is not guaranteed.

and independent power producers. At the retail level, some states have required utilities to divest their generation assets as part of restructuring. These utilities currently supply only transmission and distribution services for customers who purchase electricity (i.e., generation services) from other firms. In addition, power marketers—who often do not own generation, transmission, or distribution facilities—buy and sell power on wholesale markets and market electricity directly to customers.

Electricity competition has led to significant changes in the operation of the bulk power grid, which are the power plants and high-voltage transmission facilities that make up the wholesale power market. More electricity is being shipped longer distances over a transmission system that was initially designed only to provide limited power and reserve sharing among neighboring utilities. Electric utilities that were once solely responsible for ensuring that adequate generation was available to meet demand now purchase a substantial amount of the power they need from the wholesale market, relying on independent power producers to build and operate plants.

Electricity Generation

There are roughly 5,000 power plants in the United States, and they have a total generating capacity of nearly 800,000 megawatts. Over the past few years, there has been an explosion of "merchant" power plants proposed by independent power producers seeking to sell into wholesale markets. In spite of this interest, a number of regions of the country are experiencing capacity shortages as a result of wholesale market design problems and barriers to siting and building new power plants.

Over the next ten years, demand for electric power is expected to increase by about 25 percent, and more than 200,000 megawatts of new capacity will be required. However, under current plans electric transmission capacity will increase by only 4 percent. This shortage could lead to serious transmission congestion and reliability problems.

Transmission Grid

The United States does not have a national transmission grid. Instead, there are four integrated transmission grids serving North America: the Western Interconnection, Eastern Interconnection, Electric Reliability of Council of Texas, and the Province of Quebec (Figure 7-1). These regional grids themselves are international, encompassing the United States, Canada, and part of Mexico.

Transactions between the four integrated transmission grids are very limited because they are interconnected at only a few locations through interties, so for all practical purposes they can be viewed as separate transmission grids. The four integrated transmission grids break down into a series of smaller regions, largely defined by transmission constraints. Altogether, 204,000 miles of transmission lines in North America move power from the point of generation to where electricity is needed. There are 157,810 miles of transmission lines in the United States. Transmission grid expansions are expected to be slow over the next ten years, with additions totaling only 7,000 miles.

The transmission system is the highway system for interstate commerce in electricity. Transmission allows the sale of electricity between regions. In a particular region, transmission can be a substitute for generation, allowing that region to import power that otherwise would have to be generated within that region. In some cases, transmission expansion may be more cost effective than generation additions, allowing a region better access to lower-cost generation.

Transmission constraints limit these power flows, and result in consumers paying higher prices for electricity. The electricity price spikes in the Midwest in the summer of 1998 were caused in part by transmission constraints limiting the ability of the region to import electricity from other regions of the country that had available electricity. During the summer of 2000, transmission constraints limited the ability to sell low-cost power from the Midwest to the South during a period of peak demand,

resulting in higher prices for consumers. Transmission capacity limits could result in price pressures and reliability problems this summer in California, Long Island, the Great Lakes, the Southeast, and New En gland (Figure 7-2).

Regional shortages of generating ca pacity and transmission constraints com bine to reduce the overall reliability of elec tric supply in the country and are reducing the quality of power delivered to end users. Power quality is becoming an increasingly important issue as our digital economy con tinues to grow.

One factor limiting reliability is the lack of enforceable reliability standards. Since 1968, the reliability of the U.S. trans mission grid has depended entirely on vol untary compliance with reliability stan dards. There is a broad recognition that vol untary adherence with reliability standards is no longer a viable approach in an increas ingly competitive electricity market. There is a need to provide for enforcement of mandatory reliability standards. Broad sup port has emerged for development of these standards by a self-regulating organization overseen by FERC.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretary of Energy to work with FERC to improve the reliability of the interstate trans mission system and to develop legisla tion providing for enforcement by a self-regulatory organization subject to FERC oversight.

★ The NEPD Group recommends that the President direct the Secretary of Energy to expand the Department's research and development on trans mission reliability and superconduc tivity.

Transmission constraints were also a primary factor in blackouts in northern California, which imports power from both the Northwest and southern California. When resources are not available in the Northwest, electricity supply must come from southern California's Path 15 transmis sion route. Path 15 does not have sufficient capacity to provide all of the power needed in northern California.

Figure 7-2

Current Electric Power Bottlenecks



Transmission capacity limits could result in price pressures and reliability problems this summer in California, Long Island, the Great Lakes, the Southeast, and New England. The arrows in this figure de-pict the locations and directions of current transmission congestion.

Source: North American Electric Reliability Council.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to authorize the Western Area Power Administration to explore relieving the "Path 15" bottleneck through transmission expansion financed by nonfederal contributions.

Transmission constraints have been a persistent cause of price spikes in New York City in recent years. The New York Indepen dent System Operator (the grid operator in that state) estimates that the city will be short about 400 MW below their desired re serve margin of power during the summer peak. To fill this gap, the New York Power Authority is trying to install additional gen eration capacity in the city. Market-oriented approaches could also be used to create ad ditional capacity and alleviate some of the potential problems.

If transmission constraints are not re moved, the result can be higher prices and

lower reliability. There are various reasons why transmission constraints exist. One is the lack of sufficient investment in trans mission. Transmission investment has lagged dramatically over the past decade (Figure 7-3). There is a need to ensure that transmission rates create incentives for ad equate investment in the transmission sys tem, especially as restructuring leads to the creation of transmission companies whose only business is operation of transmission facilities. FERC recognizes this need and has expressed a willingness to consider in novative transmission pricing proposals.

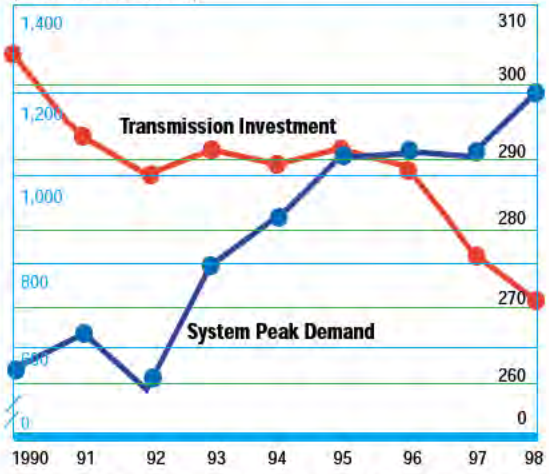
Another cause of transmission con straints is the siting process. Under current law, siting of transmission facilities is a re sponsibility of state governments, not the federal government, even though the trans mission system is not only interstate but also international, extending into both Canada and Mexico. This stands in stark contrast to siting of other interstate facili ties, such as natural gas pipelines, oil pipe lines, railroads, and interstate highways.

Federal law governing the responsibil ity for siting transmission facilities was written in 1935, nearly 80 years ago. At the time, transmission facilities were not inter-

Figure 7-3

U.S. Investment in New Electric Power Transmission

(Millions of 1990 Dollars)



Growth in peak demand for electricity has far outstripped investment in transmission capacity. As a result, transmission constraints could aggravate already limited supplies of power and could result in high prices in some areas of the country.

Source: PA Consulting Group, based on data from the UDI data base.

state, and there was virtually no interstate commerce in electricity. Congress did not anticipate the development of an interstate and international transmission system.

State decisions on where to locate transmission lines often do not recognize the importance of proposed transmission fa cilities to the interstate grid. For example, a recent decision by regulators in Connecticut to block a proposed transmission line to Long Island did not recognize the need for electricity on Long Island. Some state siting laws require that the benefits of a proposed transmission facility accrue to the indi vidual state, resulting in the rejection of transmission proposals that benefit an en tire region, rather than a single state.

Much has changed since 1935. The transmission system is the highway for in terstate commerce in electricity. Transmis sion constraints are resulting in higher prices for consumers and lower reliability. The siting process must be changed to re flect the interstate nature of the transmis sion system.

Recommendations:

★ The NEPD Group recommends that the President direct the appropriate federal agencies to take actions to re move constraints on the interstate transmission grid and allow our nation's electricity supply to meet the growing needs of our economy.

- Direct the Secretary of Energy, by December 31, 2001, to examine the benefits of establishing a national grid, identify transmission bottle necks, and identify measures to re move transmission bottlenecks.
- Direct the Secretary of Energy to work with FERC to relieve trans mission constraints by encouraging the use of incentive rate-making proposals.
- Direct the federal utilities to deter mine whether transmission expan sions are necessary to remove con straints. The Administration should review the Bonneville Power Administration's (BPA's) capital and



financing requirements in the context of its membership in a regional RTO, and if additional Treasury financing appears warranted or necessary in the future, the Administration should seek an increase in BPA's borrowing authority at that time.

- Direct the Secretary of Energy, in consultation with appropriate federal agencies and state and local government officials, to develop legislation to grant authority to obtain rights-of-way for electricity transmission lines, with the goal of creating a reliable national transmission grid. Similar authority already exists for natural gas pipelines in recognition of their role in interstate commerce.

Another cause of transmission constraints is limited access to federal lands. The federal government is the largest land owner in the United States and owns most of the land in some western states. Limited access to federal lands can block needed transmission expansion. A case in point is a transmission line being built from West Virginia to Virginia. Five years ago, the Department of Energy identified that line as critical to the reliability of the transmission system on the East Coast. Five years later, the line is still not complete. Improved access to federal land can help remove transmission constraints.

Rights-of-Way on Federal Lands

The Bureau of Land Management (BLM) estimates that 90 percent of the oil and natural gas pipeline and electric transmission rights-of-way in the western United States cross federal lands. These lands are principally lands managed by either the BLM or the U.S. Forest Service. Rights-of-way are authorized through an approval process that allows the public to comment on proposals to locate infrastructure items, like utility poles, on these rights-of way. As part of this process, proposals are examined for resource and other use conflicts, and a national interest test is applied prior to approval.

The BLM administers 85,000 rights-of-way, including 23,000 for oil and gas pipelines and 12,000 for electric transmission lines. It processes over 1,200 pipeline and electric system right-of-way applications a year, with an increase in applications of

The electric power infrastructure includes a nationwide "power grid" of long-distance transmission lines that move electricity from the point of generation to where the electricity is needed. Over the next ten years, U.S. demand for electric power is expected to increase by 25 percent, while transmission capacity is expected to increase by only 4 percent.



Virtually all natural gas in the United States is moved via pipeline. The current domestic natural gas transmission capacity of approximately 23 trillion cubic feet (tcf) will be insufficient to meet the projected 50 percent increase in U.S. consumption projected for 2020.

over 10 percent a year in recent years. The demand for additional energy and electric ity is expected to increase the need for rights-of-way across federal lands.

Other federal entities also deal with rights-of-way, each approaching the issue from a unique perspective. The National Park Service is authorized to grant leases and permits, but discourages rights-of-way corridors unless there are no practical alter natives. The U.S. Fish and Wildlife Service manages National Wildlife Refuge lands for wildlife and habitat values, and allows corri dors where they were pre-existing or are de termined to be compatible with the pur poses for which a refuge was established. The Bureau of Reclamation is authorized to grant rights-of-way over lands acquired or withdrawn for reclamation purposes, if compatible with authorized project pur poses. The Bureau of Indian Affairs and tribal governments are authorized to grant rights-of-way across both tribal and indi vidually owned Indian lands.

Pipelines

After being pumped from the ground in domestic oil fields, oil travels through gathering lines to pipelines, which bring it to refineries, where it is transformed into petroleum products like gasoline, diesel fuel, or heating oil. These products then travel through pipelines and tanker trucks to distribution outlets for purchase by con sumers. Natural gas must similarly travel from gas fields through gathering lines to processing facilities, and then into pipelines and local distribution lines to its final desti nation. These pipeline systems involve a complex infrastructure of their own, includ ing pump stations or compressor stations, and control systems that open and close valves and switch product flow through pipes, often with the use of computer tech nology.

Oil Pipelines

The two million miles of oil pipelines in the United States are the principal mode for transporting oil and petroleum products such as gasoline. They account for about 66 percent of domestic product movements (Figure 7-4). Increases in the demand for oil and changes in where it is supplied will lead to the need for more pipeline capacity.

Pipelines are less flexible than other forms of oil transport, because they are fixed assets that cannot be easily adjusted to changes in supply and demand. Once built, they are an efficient way to move pe troleum and petroleum products. A modest sized pipeline carries the equivalent of 750 tanker truckloads a day—the equivalent of a truckload leaving every two minutes, 24 hours a day, 7 days a week. Replacing the same pipeline with a railroad train of tank cars, carrying 2,000 barrels each, would re quire a 75-car train to arrive and be un loaded every day. Pipelines are relatively in expensive to operate and are generally quiet and safe. Ensuring pipeline safety requires careful management, as multiple products move through a single pipeline system at the same time.

Insufficient domestic pipeline capacity has caused peak-load problems in moving oil and petroleum products such as gasoline from one region of the country to another. For example, many energy analysts fore casted the possibility of a shortage last win ter in the upper Midwest of liquefied petro leum gas used for heating and for drying crops. Others were concerned about pos sible shortages of heating oil in New En gland.

Energy supply shortages can create operational difficulties for the pipelines themselves. The complex interrelationship

of our energy infrastructure is evident, since pipelines have been shut down for varying time periods due to regional elec tricity shortages.

For example, fuel supplies to Las Ve gas and Phoenix became dangerously low when blackouts in California shut down the main pipeline serving those areas. The Cali fornia Public Utilities Commission (CPUC) has granted a waiver of penalties to oil pipelines that have interruptible contracts for electricity to help ensure the uninter rupted flow of motor fuel supplies to Cali fornia. The California Energy Commission asked the CPUC to grant the waiver in or der to minimize the threat to public health due to disruptions of fossil fuel supplies. While the waiver of penalties does not guar antee that disruptions of power to petro leum product pipelines will not occur, it di minishes the threat by allowing disruptions to occur only when they are coordinated with the entire petroleum product delivery system, from refiner to pipeline to termi nals. Both Phoenix and Las Vegas would benefit from this decision because refiner ies and pipelines from California supply the two cities.

Much of the existing oil pipeline infra structure is old, requiring regular safety and environmental reviews to ensure its reliabil ity. The potential risk of pipeline accidents to human health and safety is of grave con cern. In June 1999, a petroleum product pipeline ruptured and caught fire in Bellingham, Washington. In addition to tragic loss of life, the pipeline's 18-month shutdown caused an economic hardship to the Seattle–Tacoma Airport and other local businesses that relied on the pipeline for aviation and diesel fuels. To avoid similar crises, the Department of Transportation, which has responsibility for pipeline safety, has adopted regulations and other risk man agement approaches to ensure safety in pipeline design, construction, testing, operation, maintenance, and emergency response.

Recommendation:

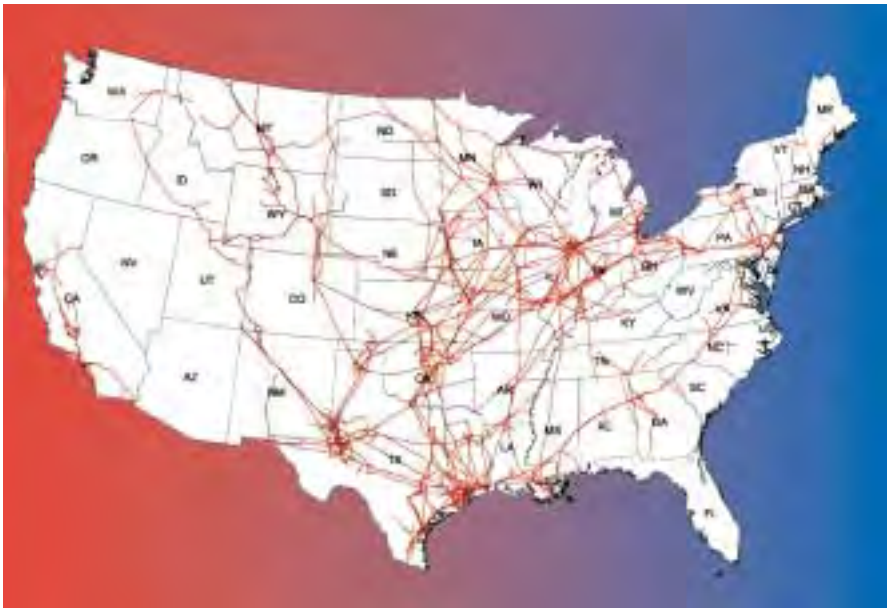
★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress and the State of Alaska to put in place the most expeditious process for renewal of the Trans-Alaskan Pipeline System rights-of-way to ensure that Alaskan oil continues to flow uninterrupted to the West Coast of the United States.

The Trans-Alaska Pipeline System is the single most important crude oil pipeline in the United States, and is perhaps the most regulated oil pipeline in the world. The pipeline system has carried nearly one-fifth of all domestically produced oil for the last two decades. Since beginning operations in 1977, it has transported more than 13 billion barrels of oil from Alaska's North Slope across 800 miles to the Port of Valdez. Since the pipeline began operation, only 0.00014 percent of the total amount of oil trans ported through it has been spilled.

The pipeline's federal grant and state lease for right-of-way expires in 2004 and will require renewal. That process will in-

Figure 7-4

U.S. Oil Pipelines



The two million miles of oil pipelines in the United States are the principal mode for transporting crude oil and refined products. They account for about 66 percent of domestic product movements.

Source: U.S. Department of Transportation, Office of Pipeline Safety.



Several federal agencies are authorized to grant rights-of-way for oil and gas pipeline and electric transmission systems on federal lands, and each approaches the issue from a unique perspective. Authorizing agencies include the Bureau of Land Management, the U.S. Forest Service the National Park Service, the U.S. Fish and Wildlife Service, the Bureau of Reclamation, and the Bureau of Indian Affairs.

volve a thorough review of compliance with federal laws and regulations, including those related to safety and environmental impacts. Because nearly 50 percent of the right-of-way is owned by the State of Alaska, they must also renew the applicable state permits. To commence the formal portion of the federal renewal process, regulations require a renewal application to be filed with the Alaska Office of the BLM of the Department of the Interior. To the extent possible, a single, joint federal/state approach should be considered.

Natural Gas Pipelines

Virtually all natural gas in the United States is moved via pipeline (Figure 7-5). The current domestic natural gas transmission capacity of approximately 23 trillion cubic feet (tcf) will be insufficient to meet the projected 50 percent increase in U.S. consumption projected for 2020.

Some parts of the country, such as California and New England, already face capacity shortages. Several pipeline operators have applied for permits to increase their delivery of natural gas to California, but right-of-way issues and local permitting delays have constrained the ability to transport natural gas to California, contributing to high prices. In addition, the natural gas pipeline connections from Canada are near capacity, so any greater U.S. reliance on Canadian natural gas will require increased pipeline capacity.

One of the largest known reserves of natural gas in the United States has been found in the Arctic, associated with the development of oil at Alaska's Prudhoe Bay. These known gas reserves, over 35 tcf, would make a significant long-term contribution to the nation's energy supplies if delivered to the lower 48 states. It is estimated there may be an additional 100 tcf on the North Slope of Alaska. Recently, as the energy supply situation has changed, interest has renewed in tapping into Alaska's natural gas supplies. Over the past year, the Alaska North Slope gas producers have been reviewing whether projected market conditions will make transportation of this natural gas economically feasible. The North Slope gas producers are scheduled to complete that review by the end of 2001.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that may be required.

America needs the energy that Alaska's North Slope natural gas can provide. The Administration seeks to expedite the construction of a pipeline to deliver this natural gas to the lower 48 states.

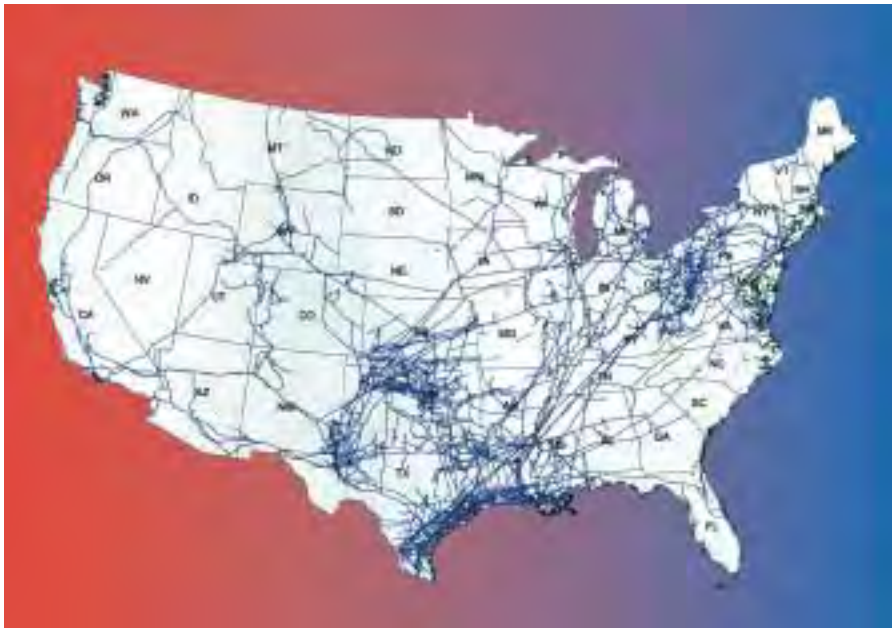
In addition to shortfalls in capacity, sources of natural gas have shifted from the Southwest to the deep water of the Gulf of Mexico, the Rocky Mountains, western Canada, and the Canadian Atlantic. At the same time, demand has shifted from the in dustrial Midwest to the growing population centers in the South and the West. An addi tional 263,000 miles of distribution pipe lines and 38,000 miles of new transmission pipelines will be necessary to meet in creased consumption and the new geo graphic realities of supply and demand.

Several factors complicate efforts to meet the need for increased pipeline capac ity, including encroachment on existing rights-of-way and heightened community resistance to pipeline construction. Cur rently it takes an average of four years to obtain approvals to construct a new natural gas pipeline. In some cases it can take much longer.

The projected growth in energy de mand has called into question whether regulatory actions and permitting processes can keep pace with the necessary construc tion of new facilities for storage and deliv ery. Consistent federal, state, and local gov ernment policies, and faster, more predict able regulatory decisions on permitting for oil and natural gas pipelines are needed to enable timely and cost-effective infrastruc ture development. The permitting process has a positive role in protecting the environ ment, public health, and safety by allowing all interested parties an opportunity to par ticipate effectively and fully in the delibera tions prior to the permit issuance.

Recent pipeline ruptures involving a natural gas pipeline near Carlsbad, New Mexico, and an underground natural gas storage facility near Hutchinson, Kansas, highlight the need to develop technologies and policies that protect people, environ ment, and the safety of the nation's energy infrastructure. The federal government has an important role in ensuring and improv ing the safety of these gas pipelines. New technologies need to be developed to im prove monitoring and assessment of system integrity, improve data quality for system planning, extend the serviceability and life of the national natural gas transmission and dis tribution network, provide safer transport of energy products, and lessen the impacts of the energy infrastructure on the environ ment.

Figure 7-5
U.S. Natural Gas Transmission Pipelines



Virtually all natural gas in the United States is moved via pipeline. The forecast of a doubling in the number of new natural gas wells drilled annually and an 80 percent increase in the number of active drilling rigs will require new pipelines.

Source: U.S. Department of Transportation, Office of Pipeline Safety.

Recommendations:

★ The NEPD Group recommends that the President support legislation to im prove the safety of natural gas pipelines, protect the environment, strengthen emergency preparedness and inspec tions and bolster enforcement.

★ The NEPD Group recommends that the President direct agencies to con tinue their interagency efforts to im prove pipeline safety and expedite pipe line permitting in an environmentally sound manner and encourage the Fed eral Energy Regulatory Commission to consider improvements in the regulatory process governing approval of interstate natural gas pipeline projects.



U.S. demand for refined petroleum products currently exceeds its domestic capacity to produce them. The refinery industry is now running at nearly 100 percent of capacity during the peak gasoline consumption season.

Oil Refineries

U.S. demand for refined petroleum products, such as gasoline and heating oil, currently exceeds our domestic capacity to produce them. The refinery industry is now running at nearly 100 percent of capacity during the peak gasoline consumption sea son and is producing record levels of needed products at other times. The excess demand has recently been met by increased imports.

The U.S. refining industry has experi enced a decade of low profitability and rates of return on investment. This has dis couraged investment in new refineries. In fact, almost 50 U.S. refineries closed over the last ten years, and no major refineries have been built in the last twenty-five years.

During the last ten years, overall refin ing capacity grew by about 1 to 2 percent a year as a result of expansion in the capacity of existing, larger refineries. Although there was a significant, sustained improvement in margins during 2000, those gains arose out of a very tight supply situation and high, vola tile prices. Industry consolidation has been a key response to this poor profitability.

The U.S. refining industry is also fac ing major infrastructure problems. While the industry expanded steadily through the 1970s, it went through a period of consoli dation after the oil shocks of 1973 and 1978. Ongoing industry consolidation, in an effort to improve profitability, inevitably leads to the sale or closure of redundant facilities by the new combined ownership. This has been particularly true of terminal facilities, which can lead to reductions in inventory and system flexibility. While excess capac ity may have deterred some new capacity investments in the past, more recently, other factors, such as regulations, have de terred investments.

Refiners are subject to significant en vironmental regulation and face several new clean air requirements over the next de cade. Refiners will face many clean fuel pro duction standards, which require the pro duction of many different kinds of gasoline and diesel fuel for different parts of the country. New Environmental Protection Agency rules will require refiners to pro duce gasoline and diesel fuel with signifi cantly lower sulfur content. New clean air requirements will benefit the environment, but will also require substantial capital in vestments and additional government per mits. The proliferation of distinct regional and state gasoline and diesel product stan dards, the significant permitting needed, and the downtime to make the needed physical and operational changes will chal lenge refiners and governments to effec tively coordinate in order to reduce the like lihood of supply shortfalls and price spikes.

Recommendation:

★ The NEPD Group recommends that the President direct the Administrator of the EPA to study opportunities to maintain or improve the environmen tal benefits of state and local "bou tique" clean fuel programs while ex ploring ways to increase the flexibility of the fuels distribution infrastructure, improve fungibility, and provide added gasoline market liquidity. In conclud ing this study, the Administrator shall consult with the Departments of En ergy and Agriculture, and other agen cies as needed.

Since 1990, refiners have met growing demand by increasing the use of existing equipment and increasing the efficiency and capacity of existing plants. Even with these efforts, however, refining capacity has be gun to lag behind peak summer demand. Price volatility and the cyclical nature of oil markets inhibit investment in supply infra structure. While investors can withstand market fluctuations for some commodities, large investments in oil exploration and de velopment—such as for drilling required to maintain a steady supply and the pipelines needed to bring supply to market—are of ten curtailed during times of low oil prices. The outcome of this lack of steady invest ment is less supply, higher prices, and the abandonment of marginal oil resources that may never be recovered.

Recommendations:-

★ The NEPD Group recommends that- the President direct the Administrator- of the Environmental Protection- Agency and the Secretary of Energy to- take steps to ensure America has ad - equate refining capacity to meet the- needs of consumers.-

- Provide more regulatory certainty to refinery owners and streamline the permitting process where pos sible to ensure that regulatory over lap is limited.
- Adopt comprehensive regulations (covering more than one pollutant and requirement) and consider the rules' cumulative impacts and benefits.

★ The NEPD Group recommends that the President to direct the Administra tor of the Environmental Protection Agency, in consultation with the Secre tary of Energy and other relevant agencies, to review New Source Re view regulations, including administra tive interpretation and implementa tion, and report to the President within 90 days on the impact of the regula tions on investment in new utility and refinery generation capacity, energy ef ficiency, and environmental protec tion.

- The NEPD Group recommends that the President direct the Attorney General to review existing enforce ment actions regarding New Source Review to ensure that the enforce ment actions are consistent with the Clean Air Act and its regula tions.

Energy Transportation Infrastructure

The infrastructure used to transport energy products includes ocean tankers; in land barges; specialized trucks for oil and refined products, such as gasoline and heat ing oil; railroad tank cars and coal cars; and the waterways, highways, and railroads upon which they travel. There is also a sub stantial inventory of river and oceanside port facilities that are used for moving en ergy materials.

Marine Transportation

Marine transportation of oil and re fined products accounts for nearly one-third of domestic shipments. Approximately 3.3 billion barrels of oil and petroleum products and 229 million short tons of coal move through the nation's ports and waterways every year.

There are three kinds of ship trans ports of domestic energy products. Tankers



Double-hulled tank barges provide distribution of petroleum products.

Nicole Leigh Reinauer and RTC 135

primarily carry Alaskan oil to the West Coast. Product tankers transport refined products from the Gulf of Mexico to the At lantic Coast, from the Gulf to the West Coast, and between ports within the West Coast. Tank barges provide coastwise distri bution of refined product imports, distribu tion from pipeline terminals, and inland dis tribution. In addition, 477 foreign tankers and 64 U.S. flag tankers deliver oil and pe troleum products to the United States. They deliver approximately 2.1 million barrels a day, for a total of 770 million barrels a year.

Ships are also used to import liquefied natural gas (LNG). With increasing demand for natural gas for electricity generation, there is a potential for substantial growth in the demand for LNG imports. From 1998 to 1999, the number of LNG carrier arrivals in Boston increased by 350 percent. In addi-- tion, mothballed terminals at Elba Island,- Georgia, and Cove Point, Maryland, may- reinitiate LNG imports by 2002.-

Winter storms, extended darkness, and ice formation disrupt barge and tanker movements. The U.S. Coast Guard's fleet of ice breakers has become an important component of the energy infrastructure for the New England, Mid-Atlantic, and Great Lakes regions.
U.S. Coast Guard



Unlike pipelines, water transportation requires the positioning of vessels to where cargoes are located. For example, it can take three weeks to move a tanker from the Gulf of Mexico to the West Coast. Conse quently, tanker markets do not respond quickly to temporary surges in demand, which typically result in price spikes.

Safety

In accordance with the Oil Pollution Act of 1990, a timeline has been established to replace all single-hulled vessels with double-hulled vessels. Many have already been replaced. Modern navigation and port services also help to prevent maritime oil spills. Spill-response technologies and coor dinated response plans are key to minimiz ing damage to property and the environ ment. Oil spill technology has improved dur ing the last decade and will continue to do so. Risk assessments, preparedness drills, and cleanup strategies are all necessary safeguards for transporting energy goods. As maritime transportation grows, port and waterway infrastructure, as well as the availability of accurate and timely naviga tion information, will continue to be impor tant for the safe, efficient delivery of energy.

New England's Dependence on Marine Transportation

New England has no refineries, and its small oil pipeline system is not connected to the interstate pipeline system. As a result, New England must rely on tanker and barge shipments of petroleum products from the south as well as direct imports from over seas. There is some question as to whether this distribution system is sufficient to meet the future needs of the region and, if not, what steps need to be taken to ensure fu ture economical, reliable energy supplies.

In recent years, lower national inven tories, market forces, and other factors have combined to create much lower inventories for petroleum products such as heating oil in the Northeast. A supply system with less capacity in reserve is more vulnerable to variations in product delivery, and is less ca pable of absorbing the disruptions in barge and tanker movements that inevitably come

with winter storms, extended darkness, and ice formation. A rapid change to colder weather affects both supply and demand: households need more fuel at the same time that harbors and rivers experience severe ice conditions.

For the New England and Mid-Atlantic seaboards, U.S. Coast Guard icebreakers have become an important component of the infrastructure necessary to provide energy to the region.

The Department of Energy established the Northeast Heating Oil Reserve to ensure heating oil supplies in the region. This emergency buffer can support a shortage for approximately ten days, which is the time required for ships to carry heating oil from the Gulf of Mexico to New York Harbor.

Even with the Reserve in place, marine transportation remains the only source of heating oil for the New England's winter months.

Recommendation:

★ The NEPD Group supports the President's budget proposal to provide $8 million to maintain the two-million-barrel Northeast Heating Oil Reserve. Operated by the private sector, the Reserve helps ensure adequate supplies of heating oil in the event that colder than normal winters occur in the Northeast United States.

Rail Transportation

Coal, which provides about 52 percent of America's electricity, is the most important single commodity carried by rail. Over the past ten years, the rail share of coal transportation has increased, primarily as a result of increases in low-sulfur western coal, which moves long distances over rail. In 1999, domestic railroads carried 68 percent of the nation's coal, and in 2000, they transported an average of 14.4 million tons of coal a week.

Transportation costs account for 30 to 50 percent of the final delivered price of coal to utilities. About 74 percent of U.S. low-sulfur coal reserves are located in Montana and Wyoming. Demand for clean coal from Wyoming's Powder River Basin is expected to increase because of its environmental benefits. However, rail capacity problems in the Powder River Basin have created a bottleneck in the coal transportation system.

With little excess capacity in the rail lines supporting the Powder River Basin, expected increases in demand could result in capacity shortfalls and delays in providing coal to power plants that are relying increasingly on "just-in-time" shipments to reduce inventory costs. Additionally, delays in other parts of the rail network, such as at key rail facilities, can undermine the efficiency and reliability of the system. There is a need to eliminate bottlenecks in the coal transportation system.

Infrastructure Security

The energy infrastructure is vulnerable to physical and cyber disruption that could threaten its integrity and safety. Disruptions could come from natural events, like geomagnetic storms and earthquakes, or could come from accidents, equipment failures, or deliberate sabotage. In addition, the nation's transportation and power infrastructures have grown increasingly complex and interdependent. Consequently, any disruption can have extensive consequences.

Transportation facilities have weathered relatively short interruptions in power as a result of natural disasters and accidents, with varying degrees of impact. In a few instances, they have experienced intermittent, lengthy outages that have affected not only primary systems, but integrated services as well, such as voice, data, Internet, and wireless networks that may be used to transmit control information. The growing reliance on computer technologies, automated monitoring and control systems, and electronic commerce makes the system more efficient and vibrant, but also requires a greater level of diligence and use of safeguards.

Accurate weather and climate forecasting can prevent millions of dollars in

damage to U.S. energy infrastructure. For example, the interaction of geomagnetic storms with the Earth's magnetic field can cause additional current to enter transmis sion lines, which at times has caused re gional grid collapse and has destroyed power plant electrical transformers. Given sufficient warning, the industry can initiate protective countermeasures, such as when several northeastern power plants shed 20 percent of their load during a July 2000 geo magnetic storm.

Improvements in forecasting can fur ther assist in the management of energy re sources and materials, can prevent power outages in many cases, and can accelerate restoration of power after outages that do occur. Also, data from extreme weather events can be used to design and build infra structure, such as transmission lines, pipe lines, and hydropower dams.

Summary of Recommendations

America's Energy Infrastructure: A Comprehensive Delivery System

★ The NEPD Group recommends that the President direct the Secretary of Energy to work with the Federal Energy Regulatory Commission (FERC) to improve the reliability of the interstate transmission system and to develop legislation provid ing for enforcement by a self-regulatory organization subject to FERC oversight.

★ The NEPD Group recommends that the President direct the Secretary of Energy to expand the Department's research and development on transmission re liability and superconductivity.

★ The NEPD Group recommends that the President direct the Secretary of Energy to authorize the Western Area Power Administration to explore relieving the "Path 15" bottleneck through transmission expansion financed by nonfederal contributions.

★ The NEPD Group recommends that the President direct the appropriate federal agencies to take actions to remove constraints on the interstate transmission grid and allow our nation's electricity supply to meet the growing needs of our economy.

- Direct the Secretary of Energy, by December 31, 2001, to examine the benefits of establishing a national grid, identify transmission bottlenecks, and identify mea sures to remove transmission bottlenecks.
- Direct the Secretary of Energy to work with FERC to relieve transmission con straints by encouraging the use of incentive rate-making proposals.
- Direct the federal utilities to determine whether transmission expansions are necessary to remove constraints. The Administration should review the Bonneville Power Administration's (BPA's) capital and financing requirements in the context of its membership in a regional RTO, and if additional Treasury fi nancing appears warranted or necessary in the future, the Administration should seek an increase in BPA's borrowing authority at that time.
- Direct the Secretary of Energy, in consultation with appropriate federal agencies and state and local government officials, to develop legislation to grant author ity to obtain rights-of-way for electricity transmission lines, with the goal of cre ating a reliable national transmission grid. Similar authority already exists for natural gas pipelines in recognition of their role in interstate commerce.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress and the State of Alaska to put in place the most expeditious process for renewal of the Trans-Alaskan Pipeline System rights-of-way to ensure that Alaskan oil continues to flow uninterrupted to the West Coast of the United States.

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that may be required.

★ The NEPD Group recommends that the President support legislation to improve the safety of natural gas pipelines, protect the environment, strengthen emergency preparedness and inspections and bolster enforcement.

★ The NEPD Group recommends that the President direct agencies to continue their interagency efforts to improve pipeline safety and expedite pipeline permitting in an environmentally sound manner and encourage FERC to consider improvements in the regulatory process governing approval of interstate natural gas pipeline projects.

★ The NEPD Group recommends that the President direct the Administrator of the EPA to study opportunities to maintain or improve the environmental benefits of state and local "boutique" clean fuel programs while exploring ways to increase the flexibility of the fuels distribution infrastructure, improve fungibility, and provide added gasoline market liquidity. In concluding this study, the Administrator shall consult with the Departments of Energy and Agriculture, and other agencies as needed.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency and the Secretary of Energy to take steps to ensure America has adequate refining capacity to meet the needs of consumers.

- Provide more regulatory certainty to refinery owners and streamline the permitting process where possible to ensure that regulatory overlap is limited.
- Adopt comprehensive regulations (covering more than one pollutant and requirement) and consider the rules' cumulative impacts and benefits.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency, in consultation with the Secretary of Energy and other relevant agencies, to review New Source Review regulations, including administrative interpretation and implementation, and report to the President within 90 days on the impact of the regulations on investment in new utility and refinery generation capacity, energy efficiency, and environmental protection.

★ The NEPD Group recommends that the President direct the Attorney General to review existing enforcement actions regarding New Source Review to ensure that the enforcement actions are consistent with the Clean Air Act and its regulations.

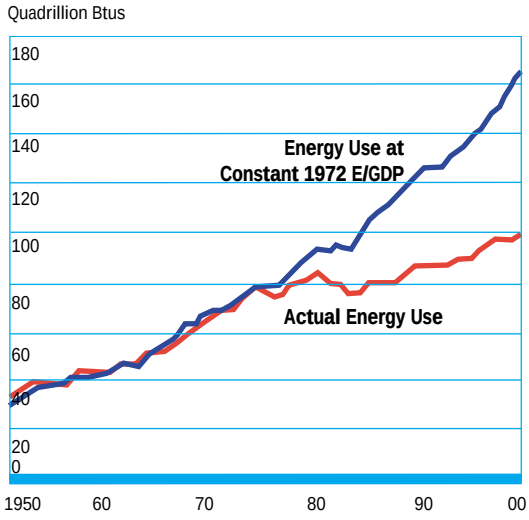
★ The NEPD Group supports the President's budget proposal to provide $8 million to maintain the two-million-barrel Northeast Heating Oil Reserve. Operated by the private sector, the Reserve helps ensure adequate supplies of heating oil in the event that colder than normal winters occur in the Northeast United States.

Strengthening Global Alliances

Enhancing National Energy Security and International Relationships

U.S. national energy security depends on sufficient energy supplies to support U.S. and global economic growth. Energy policies that have emphasized reliance on market forces have led to major energy security gains over the past two decades. Major improvements in exploration and production technology, as well as the trend toward opening new areas around the globe for exploration and development, have yielded significant dividends:

Figure 8-1
The U.S. Economy is More Energy Efficient (Energy Intensity)
Primary Energy Use



Improvements in energy efficiency since the 1970s have had a major impact in meeting national energy needs relative to new supply. If the intensity of U.S. energy use had remained constant since 1972, consumption would have been about 70 quadrillion Btus (74 percent) higher in 1999 than it actually was.

Source: U.S. Department of Energy, Energy Information Administration.

- The U.S. and world economies have diversified their sources of oil supplies, largely through increased production in the Western Hemisphere, the North Sea, and Africa.
- The world's fuel mix is also more diverse, primarily because of greater reliance on natural gas and nuclear power.
- The rate of growth in U.S. oil demand has slowed significantly since the first oil shocks of the 1970s because of more energy-efficient industries, structural changes in the economy, and greater efficiencies in vehicles, appliances, and buildings.

Since 1970, as the economy has shifted toward greater use of more efficient technologies, U.S. energy intensity (the amount of energy it takes to produce a dollar of GDP) has declined by 30 percent (Figure 8-1). However, energy use per person in the United States is expected to rise as is overall demand for energy.

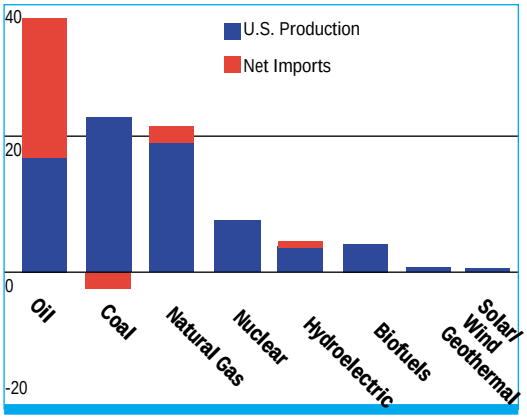
Measures to enhance U.S. energy security by meeting this increased demand must begin at home. The first step toward a sound international energy policy is to use our own capability to produce, process, and transport the energy resources we need in an efficient and environmentally sustainable manner. Market solutions to limit the growth in our oil imports would reduce oil consumption for our economy and increase our economic flexibility in responding to any domestic or international disruption of oil or other energy supplies. The United States produces 72 of the 99 quadrillion British thermal snits (Btus) of



Figure 8-2

Sources of U.S. Fuel Consumption in 1999

(Quadrillion Btus)



The United States produced 72 of the 98 quadrillion Btus of energy that it consumed in 1999. We are self-sufficient in vir tually all our energy resources, except oil, of which we import 52 percent of our net requirements, and natural gas, of which we import 15–16 percent net, primarily from Canada.

Source: U.S. Department of Energy, Energy Information Administration.

energy that it consumes (Figure 8-2). We are self-sufficient in virtually all our energy resources except oil, of which we import 52 percent of our net requirements, and natu ral gas, of which we import 15 to 16 percent of our net requirements, primarily from Canada.

We should not, however, look at en ergy security in isolation from the rest of the world. In a global energy marketplace, U.S. energy and economic security are di rectly linked not only to our domestic and international energy supplies, but to those of our trading partners as well. A significant disruption in world oil supplies could ad versely affect our economy and our ability to promote key foreign and economic policy objectives, regardless of the level of U.S. dependence on oil imports.

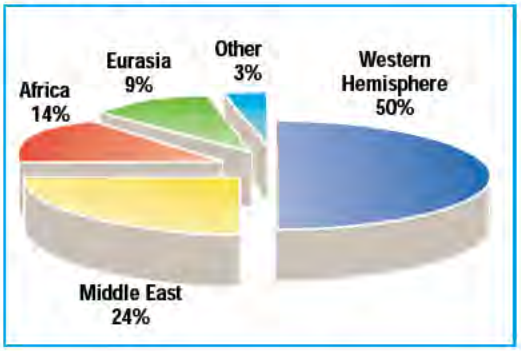
Our energy security also depends on an efficient domestic and international in frastructure to support all segments of the energy supply chain. We can strengthen our own energy security and the shared pros perity of the global economy by working cooperatively with key countries and insti tutions to expand the sources and types of global energy supplies. We can also ad vance these goals by increasing the effi ciency of energy consumption, enhancing the transparency and efficient operation of energy markets, and strengthening our ca pacity to respond to disruptions of oil sup plies. Energy is fundamental to economic growth, and we believe that economic growth and environmental protection can be mutually achieved.

We need to strengthen our trade alli ances, to deepen our dialogue with major oil producers, and to work for greater oil pro duction in the Western Hemisphere, Africa, the Caspian, and other regions with abun dant oil resources. Greater cooperation with our allies in addressing the growth in oil de mand in the transportation sector is particu larly important, given the growing demand for oil and other energy resources. Signifi cant economic and environmental benefits can be realized from increased energy effi ciency and from the use of clean energy technologies. We need to ensure that our partners in the International Energy Agency (IEA) continue to meet their obligations for emergency supply reserves. Finally, we must continue to work with the IEA, the Asia-Pacific Economic Cooperation (APEC) forum, and others to encourage other large importers to consider measures to augment their oil reserves

Oil Imports and Global Reserves

The U.S. influence on overall world markets is substantial in terms of produc tion and consumption. The United States is the world's second largest natural gas pro ducer and its third largest oil producer. The United States consumes over 25 percent of the oil produced worldwide, slightly more than half of which it imports. Nevertheless, because the price of our domestic and im ported oil is determined by a world market, our energy security interests transcend the source of our physical energy supplies (Fig ure 8-3). Given the large and projected growing volume of U.S. oil imports, our en ergy and economic security will increase if we take the steps necessary to realize America's potential as a major world oil and natural gas producer.

Figure 8-3
Regional Sources of U.S. Oil Imports in 2000



Slightly over half of the oil the United States imports every day comes from the Western Hemisphere. Canada, Venezuela, and Mexico account for the bulk (41%) of these imports.

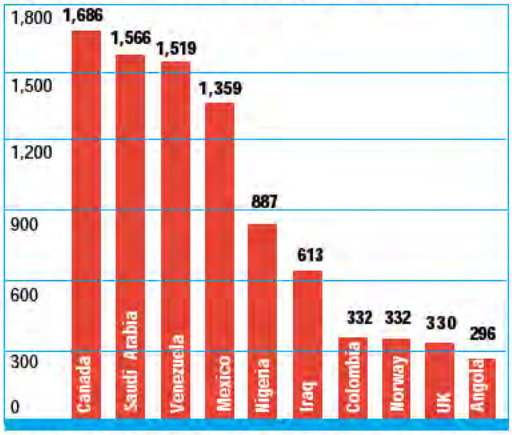
Source: US. Department of Energy, Energy Information Administration.

Recommendation:

★ The NEPD Group recommends that the President make energy security a priority of our trade and foreign policy.

In 2000, nearly 55 percent of U.S. gross oil imports came from four countries: 15 percent from Canada, 14 percent each from Saudi Arabia and Venezuela, and 12 percent from Mexico (Figure 8-4). The security of U.S. energy supply is enhanced by several factors characterizing our diplomatic and economic relationships with our four top suppliers. These factors range from geographic proximity and free trade agreements to integrated pipeline networks, reciprocal energy-sector investments, shared security commitments, and, in all cases, long-term reliable supply relationships (Figure 8-5).

Figure 8-4
Top 10 Suppliers of U.S. Oil Imports in 2000



In 2000, nearly 55 percent of gross U.S. oil imports came from four leading suppliers: Canada (15%), Saudi Arabia (14%), Venezuela (14%), and Mexico (12%).

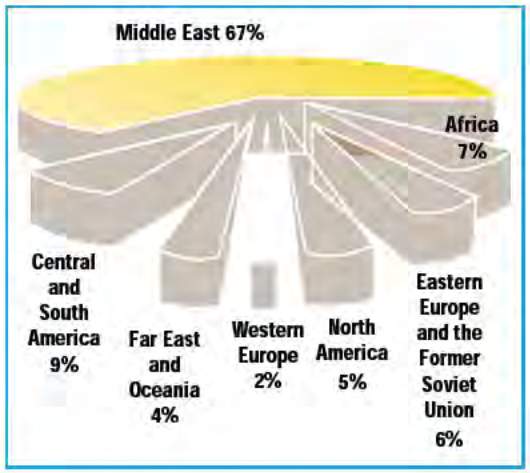
Source: U.S. Department of Energy, Energy Information Administration.

Saudi Arabia and the Middle East Oil Supplies

By 2020, Gulf oil producers are projected to supply between 54 and 67 percent of the world's oil. Thus, the global economy will almost certainly continue to depend on the supply of oil from Organization of Petroleum Exporting Countries (OPEC) members, particularly in the Gulf. This region will remain vital to U.S. interests. Saudi Arabia, the world's largest oil exporter, has been a linchpin of supply reliability to world oil markets.

Saudi Arabia has pursued a policy of investing in spare oil production capacity, diversifying export routes to both of its coasts, and providing effective assurances that it will use its capacity to mitigate the

Figure 8-5
Proven World Oil Reserves in January 2000



The world's proven crude oil reserves remain relatively concentrated. The Middle East holds 664 billion barrels, or roughly two-thirds of the world's conventional oil reserves, followed by the Western Hemisphere (14%) and Africa (7%).

Source: U.S. Department of Energy, Energy Information Administration.

Saudi Arabia has pursued a policy of investing in spare oil production capacity, diversifying export routes to both of its coasts, and providing effective assurances that it will use its capacity to mitigate the impact of oil supply disruptions in any region.
ARAMCO



impact of oil supply disruptions in any region (Figure 8-6). Algeria, Kuwait, Oman, Qatar, Saudi Arabia, the United Arab Emirates (UAE), Yemen, and other states in the region with which we maintain diplomatic relations have all, to some extent, opened their energy sectors to international investment. This development provides an important opportunity to further encourage foreign investment in these important energy-producing countries, thereby broadening our shared commercial and strategic interests. By any estimation, Middle East oil producers will remain central to world oil security. The Gulf will be a primary focus of U.S. international energy policy, but our engagement will be global, spotlighting existing and emerging regions that will have a major impact on the global energy balance.

Figure 8-6
Saudi Arabia Export Pipelines



Saudi Arabia, the world's largest oil supplier, maintains major oil export ports and storage capacity on both the Gulf and the Red Sea.

ARAMCO

Recommendation:
★ The NEPD Group recommends that the President support initiatives by Saudi Arabia, Kuwait, Algeria, Qatar, the UAE, and other suppliers to open up areas of their energy sectors to foreign investment.

Improving Market Transparency

The United States must work with oil producers to improve the transparency, timeliness, and accuracy of the data that guide global oil markets. A lack of timely and accurate data relating to both oil production and inventory levels has contributed to the price volatility witnessed in 2000. Discussions among the major oil producers and consumer countries should be designed to improve the transparency, accuracy, and timeliness of data that guide the market. In turn, enhanced data quality and increased data transparency will improve market efficiency. Refocusing that dialogue beyond short-term market developments to long-term issues of world economic growth, improving data quality, and addressing energy infrastructure is needed to maintain a smooth flow of energy from the wellhead to the consumer.

Recommendation:
★ The NEPD Group recommends that the President direct the Secretaries of State, Energy and Commerce work to improve dialogue among energy producing and consuming nations.

Promoting International Trade and Investment

Longstanding U.S. policy supports a liberalized global energy sector that is open to international trade and investment. The United States benefits from international investments at home that have increased our

energy sector's capacity and its infrastruc ture. Both producers and consumers will benefit from ensuring that the global energy infrastructure is sufficient and flexible to meet growing global demand.

American energy firms remain world leaders, and their investments in energy producing countries enhance efficiencies and market linkages while increasing envi ronmental protections. Expanded trade and investment between oil importing and ex porting nations can increase shared inter ests while enhancing global energy and eco nomic security. Promoting such investment will be a core element of our engagement with major foreign oil producers.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce and Energy to con tinue supporting American energy firms competing in markets abroad and use our membership in multilat eral organizations, such as the Asia-Pacific Economic Cooperation (APEC) forum, the Organization for Economic Cooperation and Develop ment (OECD), the World Trade Orga nization (WTO) Energy Services Ne gotiations, the Free Trade Area of the Americas (FTAA), and our bilateral relationships to implement a system of clear, open, and transparent rules and procedures governing foreign in vestment; to level the playing field for U.S. companies overseas; and to re duce barriers to trade and investment.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Energy, and the U.S. Trade Representative, to support a sectoral trade initiative to expand in vestment and trade in energy-related goods and services that will enhance exploration, production, and refining, as well as the development of new technologies.

Reviewing and Reforming Sanctions

Economic sanctions include U.S. uni lateral sanctions as well as multilateral sanctions, such as United Nations (UN) Se curity Council Resolutions. Sanctions can advance important national and global se curity objectives and can be an important foreign policy tool, especially against na tions that support terrorism or seek to ac quire weapons of mass destruction. Never theless, sanctions should be periodically re viewed to ensure their continued effective ness and to minimize their costs on U.S. citizens and interests.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of State, Treasury, and Commerce to ini tiate a comprehensive review of sanc tions. Energy security should be one of the factors considered in such a re view.

Diversity of Supply

Concentration of world oil production in any one region of the world is a potential contributor to market instability, benefiting neither oil producers nor consumers. Peri odic efforts by OPEC to maintain oil prices above levels dictated by market forces have increased price volatility and prices paid by consumers, and have worked against the shared interests of both producers and con sumers in greater oil market stability. This remains a policy challenge, which we will meet over the longer term through a com prehensive energy policy that addresses both supply and demand, as well as through increased engagement with all our major suppliers. Greater diversity of world oil pro duction remains important.

Encouraging greater diversity of oil production and, as appropriate, transporta tion, within and among geographic regions has obvious benefits to all market partici pants. Technological advances will enable the United States to accelerate the diversifi cation of oil supplies, notably through deep-



The United States is helping developing countries use energy efficient technologies. Photovoltaic-powered pumps are being used in many wells throughout rural India for collecting potable water.

U.S. Department of Energy, National Renewable Energy Laboratory

water offshore exploration and production in the Atlantic Basin, stretching from off shore Canada to the Caribbean, Brazil, and West Africa. The Caspian Sea can also be a rapidly growing new area of supply.

The ongoing development of so-called "heavy oil" reserves in the Western Hemi sphere is an important factor that promises to significantly enhance global oil reserves and production diversity. Recent Canadian and Venezuelan success in making heavy oil deposits commercially viable suggests that they will contribute substantially to the di versity of global energy supply, and to our own energy supply mix over the medium to long term. Leading non-OPEC oil exporters, such as Mexico and Norway, remain critical to the diversity of global energy supply.

Growing levels of conventional and heavy oil production and exports from the Western Hemisphere, the Caspian, and Af rica are important factors that can lessen the impact of a supply disruption on the U.S. and world economies. Overall U.S. policies in each of these high-priority re gions will focus on improving the invest ment climate and facilitating the flow of needed investment and technology.

Bilateral energy working groups, such as the U.S.-Kazakhstan Oil, Gas and Com mercial Energy Working Group and the U.S.-Russian Oil and Gas Working Group, can improve the trade climate in high-prior ity countries. In addition to seeking new sources of oil, the United States is helping developing countries use energy efficient technologies to mitigate the environmental impacts of energy use, and to improve ac cess to energy resources.

WTO members are beginning to exam ine global trade in energy services. The United States has called on WTO members to open markets eligible for private partici pation in the entire range of energy ser vices, from exploration to the final cus tomer. The energy service proposal would attempt to ensure nondiscriminatory access to foreign providers of energy services. Equally important, the U.S. proposal sug gests that WTO members consider how to best create a pro-competitive regulatory en-

Figure 8-7

Canada–U.S. Natural Gas Pipelines: 2001



Canada–U.S. Oil Pipelines: 2001



An integrated network of oil and gas pipelines demonstrates the seamless nature of North American energy trade.

Sources: Lakehead Pipe Line Company, Inc., and Canadian Association of Petroleum Producers.

Figure 8-8

Maritimes and Northeast Pipeline: 2000



New England's geography made it the "last stop" for natural gas pipelines stretching thousands of miles across the continent from the South and the West. Consequently, the region became the most oil-dependent area in the country, particularly for home heating and electricity. With the January 1, 2000, inauguration of Atlantic Canada's Maritimes and Northeast Pipeline, New England is now at the beginning of the line for natural gas flowing across the border from Canada at Calais, Maine. Overall, the region's fuel mix is becoming increasingly diversified, with natural gas demand slated to increase by 2.4 percent a year through 2020.

Source: Maritimes and NorthEast Pipeline.

vironment for energy services, so that opaque or discriminatory regulatory prac tices do not undermine commitments to open their domestic markets to foreign ser vice providers. Such objectives can also be pursued in the FTAA and APEC.

Toward a North American Energy Framework

Increased U.S., Canadian, and Mexi can energy production and cooperation would enhance energy security and, through our economic links in the North America Free Trade Agreement (NAFTA) economy, fundamentally advance each country's economic security. As state and federal governments consider energy re forms, there will be a need to ensure com patible regulatory frameworks with our neighbors while recognizing differences in jurisdictions.

Canada

Canada's deregulated energy sector has become America's largest overall en ergy trading partner, and our leading for eign supplier of natural gas, oil, and elec tricity. Canada's sustainable development based energy strategies contribute to the health of the NAFTA economy and of our shared environment.

Canada provided 14 percent of U.S. natural gas supply last year. An integrated network of pipelines demonstrates the seamless nature of North American energy trade (Figure 8-7). Estimated natural gas deposits in Alaska and Northwest Canada exceed 70 trillion cubic feet, representing over three years of total U.S. consumption at present levels.

To advance shared economic and en vironmental objectives, the private sector is poised to develop the continent's northern gas reserves, with pipeline linkages be tween both countries. To the east, recent development of Canada's Atlantic offshore energy reserves has made significant strides, with major offshore natural gas and oil production now available. Canada's At lantic energy development is now providing previously untapped sources of clean-burn ing natural gas not only to Nova Scotia and New Brunswick but also to heating oil-de pendent New England (Figure 8-8).



Offshore oil platform near Campeche, Mexico. Mexico's large crude oil reserves—approximately 25 percent larger than our own proven reserves—makes it a likely source of increased oil production over the next decade.

U.S. EMBASSY, MEXICO CITY

Our large cross-border electricity trade flows in each direction. Our electric ity imports from Canada are derived largely from hydropower produced in eastern Canada, Canadian and American hydro power projects in the Pacific Northwest op erating pursuant to the Columbia River Treaty, and a nuclear power plant in New Brunswick. All of these sources provide im portant trade and clean air benefits, while allowing both countries to benefit from load sharing and integration. The reliability of the North American electricity grid can be enhanced yet further through closer coordi nation and compatible regulatory and juris dictional approaches.

Canada's oil trade, responding to mar ket signals, increased 4 percent worldwide and 10 percent with the United States last year. Estimates of Canada's recoverable heavy oil sands reserves are substantial, and new technologies are being deployed to de velop their potential. Production from these promising areas now approaches 600,000 barrels a day. Their continued development can be a pillar of sustained North American energy and economic security.

Mexico

Our energy relationship with Mexico reflects the increasingly interrelated charac ter of NAFTA economies and our contigu ous border. U.S. natural gas reserves, pipe-

Figure 8-9

Mexican Oil and Gas Resources: 2001



Mexico's large oil reserves—approximately 25 percent larger than U.S. proven reserves—make it a likely source of increased oil production over the next decade.

Source: U.S. Central Intelligence Agency.

lines, and industries are closer to the grow ing border area than some of Mexico's re serves. The United States is a net exporter of refined petroleum products and natural gas to Mexico, primarily through pipeline connections to northern Mexico. Mexico is a leading and reliable source of imported oil, and its large reserve base, approxi mately 25 percent larger than our own proven reserves, makes Mexico a likely source of increased oil production over the next decade (Figure 8- 9).

Mexico began exporting 50 megawatts of electricity from Baja to California in Janu ary 2001. However, the transmission infra structure on both sides of the border is in sufficient for greater flows of energy in ei ther direction without expansion. In the United States, our process for "Presidential Permitting" of cross-border infrastructure linkages needs to be updated and stream lined.

Mexico will make its own sovereign decisions on the breadth, pace, and extent to which it will expand and reform its electric ity and oil and gas capacities. Where the country has opened its energy sector to pri vate investment, such as in natural gas trans mission, distribution, and storage, invest ments have been made to our mutual ben efit. To the extent Mexico seeks to attract additional foreign investment consistent with its Constitution, which reserves explo ration and production rights to the Mexican government, the United States should ac tively encourage the U.S. private sector to consider market-based investments.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to en gage in a dialogue through the North American Energy Working Group to develop closer energy integration among Canada, Mexico, and the United States and identify areas of co operation, fully consistent with the countries' respective sovereignties.

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, in consultation with the Federal Energy Regulatory Com mission, to review their respective oil, natural gas, and electricity cross boundary "Presidential Permitting" authorities, and to propose reforms as necessary in order to make their own regulatory regimes more compatible for cross-border trade.

A carrier transports liquefied natural gas (LNG) from Trinidad and Tobago—our largest LNG supplier—to Boston harbor. LNG currently represents 16 percent of New England's natural gas supply.
Cabot LNG



★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commis sion, to work closely with Canada, the State of Alaska, and all other inter ested parties to expedite the construc tion of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transporta tion Act of 1976 that may be required.

South America: Latin America and the Caribbean

Latin America and the Caribbean are growing not only as major producing re gions, but also as major consumers of oil and natural gas. Trinidad and Tobago's pro gressive investment code has made it the hemisphere's largest exporter of LNG and the largest supplier of LNG to the United States in 2000. Unprecedented development of Central and South America's vast natural gas reserves—222.7 trillion cubic feet as of January 2000, illustrated by transcontinen tal pipelines linking Bolivia, Brazil, Argen tina, Chile, Paraguay, and Uruguay—in crease regional self-reliance, affirm eco nomic integration, aid the environment, and stem the growth in oil demand. Colombia has also become an important supplier of oil to the United States.

The United States, with Venezuela, is a co-coordinator of the Hemispheric En ergy Initiative process. In March 2001, a Summit of the Americas Hemispheric En ergy Ministerial meeting was hosted by the Government of Mexico. At the meeting, the region's energy ministers pledged to sup port integration and sustainable develop ment in the hemisphere, recognizing the need to foster stable and transparent regu latory frameworks. In April 2001, the thirty four democratically elected leaders of the Western Hemisphere met in Quebec City for the Third Summit of the Americas. They called for a renewed effort to strengthen the hemisphere's energy cooperation and integration.



U.S. Secretary of Energy Spencer Abraham listens to his colleagues at the Summit of the Ameri-cas Hemispheric Energy Ministerial meeting in Mexico City on March 9, 2001.

U.S. Embassy, Mexico City

Venezuela is the world's fifth largest oil exporter, and the third largest oil sup plier to the United States. Its energy indus try is increasingly integrated into the U.S. marketplace. Venezuela's downstream in vestments in the United States make it a leading refiner and gasoline marketer here. Growing U.S. and international investments in Venezuela's energy sector, particularly in its resource-rich heavy oil sector, are en hancing the country's ability to meet its de velopment goals and to keep pace with a growing world energy marketplace. Venezu ela is also moving to liberalize its natural gas sector, which will increase opportuni ties for foreign investment to expand Ven ezuelan natural gas production. These posi tive steps along with conclusion of a Bilat eral Investment Treaty, which is now being negotiated, would provide investors from both the United States and Venezuela incen tives for increased investment.

Brazil has long been a pioneer in the development of deep-water offshore oil and gas resources. Its world-class oil industry is now moving to become a partner with U.S. and international investors to more fully de velop its prolific offshore oil reserves. This welcome development will enhance hemi spheric energy production from well-estab lished sedimentary basins.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretaries of State and Commerce to conclude ne gotiations with Venezuela on a Bilat eral Investment Treaty, and propose formal energy consultations with Bra zil, to improve the energy investment climate for the growing level of energy investment flows between the United States and each of these countries.

★ The NEPD Group recommends that the President direct the Secretaries of Energy, Commerce, and State to work through the Summit of the Americas Hemispheric Energy Initiative to de velop effective and stable regulatory frameworks and foster reliable supply sources of all fuels within the region.

Africa

Sub-Saharan Africa holds 7 percent of world oil reserves and comprises 11 percent of world oil production. Along with Latin America, West Africa is expected to be one of fastest-growing sources of oil and gas for the American market. African oil tends to be of high quality and low in sulfur, making it suitable for stringent refined product re quirements, and giving it a growing market share for refining centers on the East Coast of the United States.

In 2000, OPEC member Nigeria ex ported an average of 900,000 barrels of oil per day to the United States, out of its total production of 2.1 million barrels of oil per day. Nigeria, in partnership with the private sector, has set ambitious production goals as high as 5 million barrels of oil per day over the coming decade.

Angola's growing offshore oil indus try, with participation by U.S. and interna tional oil firms, is also a major source of growth. In 2000, Angola exported 300,000 barrels of oil per day out of its 750,000 bar rels of oil per day of total production to the United States, and is thought to have the potential to double its exports over the next ten years. Other significant exporters to the United States included Gabon and the Congo-Brazzaville.

The World Bank has supported Chad's efforts to begin ambitious oil development. This year an international consortium that includes U.S. firms began investing $3.5 bil lion in this pipeline from Chad to Cameroon, the largest infrastructure project in Africa to day. When complete, the pipeline will allow Chad to export up to 250,000 barrels of oil per day.

The U.S. Agency for International De velopment (USAID) has provided technical assistance in support of a West Africa Power Pool and associated pipeline project involving a number of U.S. oil companies, and is providing assistance for the creation of a regional regulatory framework that will enable Ghana and Nigeria to become major exporters of natural gas and electricity.

The West Africa Gas Pipeline is a 161 mile (1,000-kilometer), $400 million on shore/offshore natural gas pipeline connect ing Nigeria with Benin, Togo, and Ghana. The pipeline is being built by a consortium of companies, and includes financing by the U.S. Export-Import Bank.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretaries of State, Energy, and Commerce to rein vigorate the U.S.-Africa Trade and Economic Cooperation Forum and the U.S.-African Energy Ministerial pro cess; deepen bilateral and multilateral engagement to promote a more recep tive environment for U.S. oil and gas trade, investment, and operations; and promote geographic diversification of energy supplies, addressing such is sues as transparency, sanctity of con tracts, and security.

★ The NEPD Group recommends that the President direct the Secretaries of State, Energy, and Commerce to re cast the Joint Economic Partnership Committee with Nigeria to improve the climate for U.S. oil and gas trade, investment, and operations and to ad vance our shared energy interests.

★ The NEPD Group recommends that the President direct the Secretaries of

State, Energy, and Commerce to support more transparent, accountable, and responsible use of oil resources in African producer countries to enhance the stability and security of trade and investment environments.

The Caspian

Proven oil reserves in Azerbaijan and Kazakhstan are about 20 billion barrels, a little more than the North Sea and slightly less than the United States. Exploration, however, is continuing, and proven reserves are expected to increase significantly.

For example, initial results of the exploration well at Kazakhstan's Kashagan field indicate the find is one of the most important in thirty years, and is comparable to Prudhoe Bay in size. Current exports from the region are only about 800,000 barrels of oil per day, in part due to limited export route options. However, potential exports could increase by 1.8 million barrels of oil per day by 2005, as the United States works closely with private companies and countries in the region to develop commercially viable export routes, such as the Baku-Tbilisi-Ceyhan (BTC) and Caspian Pipeline Consortium oil pipelines (Figure 8-10). Moreover, there is considerable optimism that exports could grow even more substantially in subsequent years because of positive prospects for new oil and gas finds as additional geologic structures undergo exploration, and the development of new export routes.

Foreign investors and technology are critical to rapid development of new commercially viable export routes. Such development will ensure that rising Caspian oil production is effectively integrated into world oil trade. U.S.-supported East–West pipeline routes will add substantial new oil transportation capacity to allow continued expansion of production and exports. Overland routes via pipeline, such as the planned BTC oil pipeline, will also help mitigate maritime risks in the crowded Bosporus Straits. To help countries prepare for increased oil production within the region, the United States is working with Black Sea and Caspian Sea border states to ensure that they develop adequate oil spill response capabilities.

Figure 8-10

Caspian Energy Export Pipelines: 2001



Several oil and natural gas pipeline projects are proposed for the Caspian area.

Source: U.S. Central Intelligence Agency.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the BTC oil pipeline as it demonstrates its commercial viability.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to continue working with relevant companies and countries to establish the commercial conditions that will allow oil companies operating in Kazakhstan the option of exporting their oil via the BTC pipeline.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the efforts of private investors and regional governments to develop the Shah Deniz gas pipeline as a way to help Turkey and Georgia diversify their natural gas supplies and help Azerbaijan export its gas via a pipeline that will continue diversification of secure energy supply routes.

★ The NEPD Group recommends that the President direct appropriate federal agencies to complete the current cycle of oil spill response readiness workshops and to consider further appropriate steps to ensure the implementation of the workshops' recommendations.

★ The NEPD Group recommends that the President direct the Secretary of State to encourage Greece and Turkey to link their gas pipeline systems to allow European consumers to diversify their gas supplies by purchasing Caspian gas.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, Energy, and State to deepen their commercial dialogue with Kazakhstan, Azerbaijan, and other Caspian states to provide a strong, transparent, and stable business climate for energy and related infrastructure projects.

Russia

Russia has about 5 percent of the world's proven oil reserves. In 2000, Russia produced an average of 6.7 million barrels of oil and natural gas liquids per day, making it both the world's third largest producer and second largest exporter at 4.2 million barrels of oil per day. Russia's oil production in 2000 represented an increase of 7 percent over 1999, the first increase since the dissolution of the Soviet Union. A similar rate of increase is projected for 2001. New fields are being developed, including those with U.S. and other foreign investors.

Nevertheless, substantial infrastructure investment is still needed, as well as legislation and a stable and reliable regime of contracting to finalize the Production Sharing Agreement (PSA) mechanism for private-sector participation and actions to improve the general investment climate. Russian oil firms are increasingly active on a global scale, with upstream and downstream investments in the Caspian, the United States, Africa, South Asia, and Europe, enhancing Russia's ability to develop its own and international oil reserves.

Russia holds 33 percent of the world's natural gas reserves, exporting a full 35 percent of its production to Europe and Central Asia in 1999. Russian natural gas exports can increase regional fuel diversification and advance environmental goals. With production declines now evident in existing fields, development of new reserves that require substantial new investments will be necessary.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to deepen the focus of the discussions with Russia on energy and the investment climate.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to assist U.S. companies in their dialogue on the investment and trade climate with

Russian officials, to encourage reform of the PSA law and other regulations and related tax provisions, as well as general improvements in the overall investment climate. This will help ex pand private investment opportunities in Russia and will increase the inter national role of Russian firms.

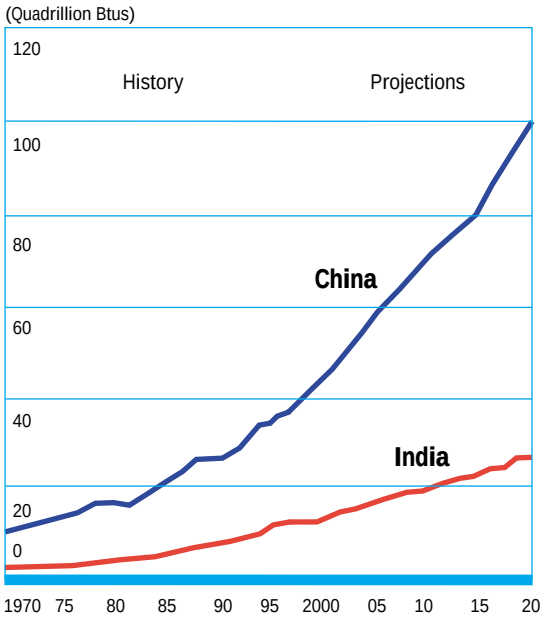
Asia

Asia holds less than 5 percent of world proven oil reserves, but accounts for more than 10 percent of oil production and about 30 percent of world oil consumption. The developing countries of the Pacific Rim are expected to increase their total petro leum imports by almost 43 percent between 1997 and 2020. The developing countries of Asia are expected to remain heavily depen dent on Middle East imports.

China is a critical player in global en ergy security issues, since its net oil im ports are expected to rise from approxi mately 1 million barrels of oil per day at present to possibly 5 to 8 million barrels of oil per day by 2020, with a predominant (over 70 percent) dependence on Middle East imports. China moved in the mid-1990s from being a net oil exporter to a net oil im porter.

About 7 percent of the world's proven natural gas reserves are located in Asia. Asian gas production represents about 11 percent of the world total, and consumption is less than 3 percent of world natural gas demand. Other natural gas producers, such as Malaysia, Myanmar, and Australia, are net gas exporters. Currently Japan, South Korea, and Taiwan are the major gas im porters in Asia. China, in addition to accel erating domestic exploration and develop ment of natural gas resources, is planning to import gas via pipeline from Central Asia. India, likewise, is considering several po tential LNG import projects (Figure 8-11).

Figure 8-11
Energy Consumption in China and India: 1970–2020



China and India account for the bulk of projected growth in oil demand in non-OECD countries.

Source: U.S. Department of Energy, Energy Information Administration.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to con tinue to work in the APEC Energy Working Group to examine oil market data transparency issues and the vari ety of ways petroleum stocks can be used as an option to address oil mar ket disruptions.

★ The NEPD Group recommends that the President direct the Secretaries of State and Energy to work with India's Ministry of Petroleum and Natural Gas to help India maximize its domestic oil and gas production.

Diversification of Fuel Mix

The growing demand for more fuel efficient technologies offers U.S. businesses significant trade and investment opportuni ties overseas, while addressing rising world oil demand. The United States supports a practical, market-based approach that en

courages the adoption of efficient technolo gies, including those relating to natural gas, nuclear energy, and renewable energy. This approach takes into account existing na tional and international programs and has the potential to energize both public action and private involvement. Introduction of these technologies abroad also supports U.S. national interests by reducing competi tion for the oil resources on which the glo bal economy continues to rely. Overall, the U.S. government's goal is to adopt policies that support innovative finance and market mechanisms that will provide U.S. busi nesses and consumers greater incentives to make more cost effective, energy efficient investment and consumption decisions.

Increased use of renewable energy technologies would improve U.S. energy se curity, yield global environmental benefits, improve social and economic stability in the developing world, and provide significant trade and investment opportunities to U.S. businesses. Promotion of clean energy tech nology exports can mitigate international dependence on oil supplies from volatile re gions, help lower energy costs for U.S. con sumers, bring U.S. firms greater access to large foreign markets, and enhance U.S. in tegration with global sources of innovation. In consultation with U.S. industry, the U.S. government is participating in efforts of the IEA, the G-8, the OECD, the United Nations, and multilateral development banks to for mulate effective strategies for accelerated market penetration of renewable energy technologies. Significant market penetra tion will depend on further reducing the costs of deploying these technologies.

The Clean Energy Technology Exports Working Group, a Federal interagency task force comprised of USAID and the Depart ments of Commerce and Energy, is creating a strategic plan that will provide a roadmap for future exports of U.S. clean energy tech nologies. Through its international trade programs, the Department of Commerce will showcase market-ready U.S. technolo gies that generate a cleaner environment and increase energy efficiency.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to pro mote market-based solutions to envi ronmental concerns; support exports of U.S. clean energy technologies and encourage their overseas develop ment; engage bilaterally and multilat erally to promote best practices; ex plore collaborative international basic research and development in energy alternatives and energy efficient tech nologies; and explore innovative pro grams to support the global adoption of these technologies.

Climate Change

The President is committed to ad dressing the issue of global climate change in a manner that protects our environment and economy. Toward this end, the Admin istration is undertaking a Cabinet-level re view of domestic and international policies for addressing this issue.

The United States invited other nations to re-examine global climate change issues, including technologies and market-based systems. Increasing our understanding of the most recent science and further research into the science of climate change will be es sential to developing the optimal strategy.

There is increasing awareness of glo bal competition for fossil fuels and their po tential threats to the global environment. The United States can diminish both risks by becoming more energy efficient at home, by working with other nations, and by en couraging developing countries to use the cleanest and most energy-efficient technolo gies. Through educational programs, the United States can encourage developing countries to use advanced U.S. energy tech nologies, energy management practices, and market-based policies. The United States is uniquely positioned to help emerging na tions build energy and institutional capacity and to finance energy-related activities and services. Doing so could prove to be a cost effective investment, for both the United States and emerging economies.

Recommendation:

★ The NEPD Group recommends that the President direct federal agencies to support continued research into global climate change; continue efforts to identify environmentally and cost-effective ways to use market mechanisms and incentives; continue development of new technologies; and cooperate with allies, including through international processes, to develop technologies, market-based incentives, and other innovative approaches to address the issue of global climate change.

Oil Consumption

Although U.S. energy security can be reinforced by domestic efforts to enhance supply and use energy more efficiently, growth in international oil demand will exert increasing pressure on global oil availability. Worldwide oil consumption is projected to grow by 2.1 percent a year over the next two decades. However, oil demand is projected to grow three times as fast in non-OECD countries as in OECD countries, which will increase worldwide competition for global oil supplies and put increased pressure on our shared environment. Accordingly, non-OECD countries' share of oil demand is expected to rise from 41 percent to 52 percent (Figure 8-12). China and India will be major contributors to this growth in demand and will rely heavily on imports to meet their needs. This growth will increase the stake that many developing countries have in ensuring access to significant energy resources, as well as their incentive to pursue energy efficiency.

Transportation has been responsible for nearly all the growth in OECD oil consumption over the last twenty years, and is projected to be the leading source of future growth in oil consumption through 2020. Transportation-related fuel consumption in the developing world is expected to more than double by 2020, growing at an annual average rate of 4 percent. Therefore, both OECD and developing countries will need to increase their focus on efficiencies in the transportation sector. The momentum to create market mechanisms supporting alternative-fuel vehicles will increase. Best practices that seek to reduce the cost of these technologies and to promote market penetration should be pursued. Without additional efforts to reduce this growth in consumption, the transportation sector's fuel needs will force an increasing dependence on oil in the developed and developing worlds.

Recommendations:

★ The NEPD Group recommends that the President seek to increase international cooperation on finding alternatives to oil, especially for the transportation sector.

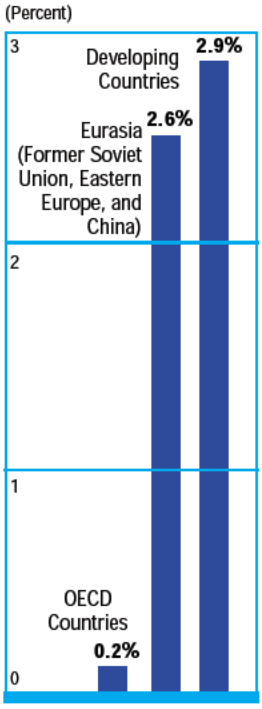
★ The NEPD Group recommends that the President direct the Secretary of State to reinvigorate its dialogue with the European Union on energy issues, and resume the consultative process this year in Washington.

★ The NEPD Group recommends that the President promote a coordinated approach to energy security by calling for an annual meeting of G-8 Energy Ministers or their equivalents.

Emergency Preparedness for Oil Supply Disruption

U.S. and world exposure to oil supply disruptions increases as the size of strategic and commercial stocks relative to demand declines. This vulnerability is a result of rising global demand, tight supplies, and inadequate efforts to establish or expand oil stockpiles. Such a situation magnifies the importance of U.S. coordination with other members of the IEA, comprised of most OECD member governments. Each IEA member that is a net oil importer is required to hold stocks equal to 90 days or more of its net imports. The IEA maintains agreed mechanisms for coordinating the use of these stocks in responding to a physical supply disruption. Collectively, the net oil-importing members of the IEA currently hold

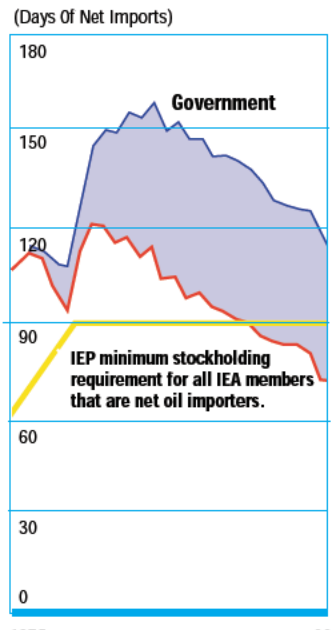
Figure 8-12
Projected Oil Consumption Rates in Three Economic Regions: 1999–2020



Over the next two decades, oil consumption in developing countries and Eurasia will grow three times faster than in the rest of the world.

Source: U.S. Department of Energy, Energy Information Administration.

Figure 8-13
Stocks of IEA Net Importers: 1975–2000



The International Energy Agency, of which the United States is a member, closely tracks the amount of strategic and commercial petroleum stocks maintained by its member states. The International Energy Program (IEP) Agreement "binds Participating Countries to make specific measures to meet any oil supply emergency and, over the long term, to reduce dependence on oil."

Source: International Energy Agency.

approximately 113 days worth of strategic and commercial stocks. U.S. stocks, which include both government and commercial stocks, are slightly above the IEA average. While this is more than required, it is far be low the peak coverage of 157 days reached in 1986. Moreover, several member states have fallen below the 90-day threshold (Fig ure 8-13).

The United States meets part of its IEA obligation through government-owned stocks held in the U.S. Strategic Petroleum Reserve (SPR). The SPR currently holds 541 million barrels of oil, which is enough to cover the loss of all U.S. imports for 54 days or a partial disruption for much longer. Close to 33 million barrels of oil will be de posited in the SPR by the fourth quarter of 2002, returning oil that had been "ex changed" out of the reserve last year. SPR oil can be withdrawn at a maximum rate of over 4 million barrels of oil per day initially and could reach the market within fifteen days of a Presidential directive. Because of increased net oil imports, the days of oil im port coverage provided by the SPR have de clined considerably over the past decade. In 1990, the SPR contained enough oil to com pensate for the loss of 82 days worth of U.S. imports—substantially more than today's 54-day supply. As domestic production and import patterns evolve, the Administration will work to inform Congress about chang ing coverage levels provided by the SPR. It should be noted that the United States also counts on the SPR as a national defense fuel reserve.

The oil market's day-to-day operation and its ability to respond to supply prob lems depend heavily on the availability of information on supply, demand, and price. The oil market volatility of the past two years has emphasized the need for more comprehensive and timely oil market infor mation.

Recommendations:

★ The NEPD Group recommends that the President reaffirm that the SPR is designed for addressing an imminent or actual disruption in oil supplies, and not for managing prices.

★ The NEPD Group recommend that the President direct the Secretary of Energy to work within the Interna tional Energy Agency (IEA) to ensure that member states fulfill their stock holding.

★ The NEPD Group recommends that the President direct the Secretary of Energy to encourage major oil-con suming countries that are not IEA members to consider strategic stocks as an option for addressing potential supply disruptions. In this regard, we should work closely with Asian econo mies, especially through APEC.

★ The NEPD Group recommends that the President direct the Secretary of Energy offer to lease excess SPR stor age facilities to countries (both IEA and non-IEA members) that might not otherwise build storage facilities or hold sufficient strategic stocks, consis tent with statutory authorities.

★ The NEPD Group recommends that the President, at such time that ex changed SPR barrels are returned to the SPR, should determine whether offshore Gulf of Mexico royalty oil de posits to the SPR should be resumed, thereby increasing the size of our re serve.

★ The NEPD Group recommends that the President direct the Secretary of Energy to work closely with Congress to ensure that our SPR protection is maintained.

★ The NEPD Group recommends that the President direct the Secretary of Energy to work with producer and consumer country allies and the IEA to craft a more comprehensive and timely world oil data reporting system.

Summary of Recommendations

Strengthening Global Alliances: Enhancing National Energy Security and International Relationships

★ The NEPD Group recommends that the President make energy security a priority of our trade and foreign policy.

★ The NEPD Group recommends the President support initiatives by Saudi Arabia, Ku wait, Algeria, Qatar, the UAE, and other suppliers to open up areas of their energy sec tors to foreign investment.

★ The NEPD Group recommends that the President direct the Secretaries of State, En ergy and Commerce work to improve dialogue among energy producing and consuming nations.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to continue supporting American energy firms competing in markets abroad and use our membership in multilateral organizations, such as the Asia-Pacific Economic Cooperation (APEC) forum, the Organization for Economic Coopera tion and Development (OECD), the World Trade Organization (WTO) Energy Services Negotiations, the Free Trade Area of the Americas (FTAA), and our bilateral relation ships to implement a system of clear, open, and transparent rules and procedures gov erning foreign investment; to level the playing field for U.S. companies overseas; and to reduce barriers to trade and investment.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Energy, and the U.S. Trade Representative, to support a sectoral trade initiative to expand investment and trade in energy-related goods and services that will enhance ex ploration, production, and refining, as well as the development of new technologies.

★ The NEPD Group recommends that the President direct the Secretaries of State, Treasury, and Commerce to initiate a comprehensive review of sanctions. Energy secu rity should be one of the factors considered in such a review.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to engage in a dialogue through the North American Energy Working Group to develop closer energy integration among Canada, Mexico, and the United States and identify areas of cooperation, fully consistent with the countries' re spective sovereignties.

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, in consultation with the Federal Energy Regulatory Commission, to review their respective oil, natural gas, and electricity cross-boundary "Presidential Permitting" authorities, and to propose reforms as necessary in order to make their own regulatory regimes more compatible for cross-border trade.

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that may be required.

★ The NEPD Group recommends that the President direct the Secretaries of State and Commerce to conclude negotiations with Venezuela on a Bilateral Investment Treaty, and propose formal energy consultations with Brazil, to improve the energy invest ment climate for the growing level of energy investment flows between the United States and each of these countries.

★ The NEPD Group recommends that the President direct the Secretaries of Energy, Commerce, and State to work through the Summit of the Americas Hemispheric En ergy Initiative to develop effective and stable regulatory frameworks and foster reli able supply sources of all fuels within the region.

★ The NEPD Group recommends that the President direct the Secretaries of State, Energy, and Commerce to reinvigorate the U.S.-Africa Trade and Economic Coopera tion Forum and the U.S.-African Energy Ministerial process; deepen bilateral and mul tilateral engagement to promote a more receptive environment for U.S. oil and gas trade, investment, and operations; and promote geographic diversification of energy supplies, addressing such issues as transparency, sanctity of contracts, and security.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support more transparent, accountable, and responsible use of oil resources in African producer countries to enhance the stability and security of trade and investment environments.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the BTC oil pipeline as it demonstrates its commer cial viability.

★ The NEPD Group recommends that the President direct the Secretaries of Com merce, State, and Energy to continue working with relevant companies and countries to establish the commercial conditions that will allow oil companies operating in Kazakhstan the option of exporting their oil via the BTC pipeline.

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★ The NEPD Group recommends that the President direct appropriate federal agen cies to complete the current cycle of oil spill response readiness workshops and to consider further appropriate steps to ensure the implementation of the workshops' recommendations.

★ The NEPD Group recommends that the President direct the Secretary of State to encourage Greece and Turkey to link their gas pipeline systems to allow European consumers to diversify their gas supplies by purchasing Caspian gas.

★ The NEPD Group recommends that the President direct the Secretaries of Com merce, Energy, and State to deepen their commercial dialogue with Kazakhstan, Azerbaijan, and other Caspian states to provide a strong, transparent, and stable business climate for energy and related infrastructure projects.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to deepen the focus of the discussions with Russia on energy and the investment climate.

★ The NEPD Group recommends that the President direct the Secretaries of Com merce, State, and Energy to assist U.S. companies in their dialogue on the investment and trade climate with Russian officials, to encourage reform of the PSA law and other regulations and related tax provisions, as well as general improvements in the overall investment climate. This will help expand private investment opportunities in Russia and will increase the international role of Russian firms.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to continue to work in the APEC Energy Working Group to ex amine oil market data transparency issues and the variety of ways petroleum stocks can be used as an option to address oil market disruptions.

★ The NEPD Group recommends that the President direct the Secretaries of State and Energy to work with India's Ministry of Petroleum and Natural Gas to help India maxi mize its domestic oil and gas production.

★ The NEPD Group recommends that the President direct the Secretaries of Com merce, State, and Energy to promote market-based solutions to environmental con cerns; support exports of U.S. clean energy technologies and encourage their overseas development; engage bilaterally and multilaterally to promote best practices; explore collaborative international basic research and development in energy alternatives and energy-efficient technologies; and explore innovative programs to support the global adoption of these technologies.

★ The NEPD Group recommends that the President direct federal agencies to support continued research into global climate change; continue efforts to identify environ mentally and cost-effective ways to use market mechanisms and incentives; continue development of new technologies; and cooperate with allies, including through inter national processes, to develop technologies, market-based incentives, and other inno vative approaches to address the issue of global climate change.

★ The NEPD Group recommends that the President seek to increase international co operation on finding alternatives to oil, especially for the transportation sector.

★ The NEPD Group recommends that the President direct the Secretary of State to re invigorate its dialogue with the European Union on energy issues, and resume the con sultative process this year in Washington.

★ The NEPD Group recommends that the President promote a coordinated approach to energy security by calling for an annual meeting of G-8 Energy Ministers or their equivalents.

★ The NEPD Group recommends that the President reaffirm that the SPR is designed for addressing an imminent or actual disruption in oil supplies, and not for managing prices.

★ The NEPD Group recommend that the President direct the Secretary of Energy to work within the International Energy Agency (IEA) to ensure that member states ful fill their stockholding.

★ The NEPD Group recommends that the President direct the Secretary of Energy to encourage major oil-consuming countries that are not IEA members to consider strate gic stocks as an option for addressing potential supply disruptions. In this regard, we should work closely with Asian economies, especially through APEC.

★ The NEPD Group recommends that the President direct the Secretary of Energy of fer to lease excess SPR storage facilities to countries (both IEA and non-IEA mem bers) that might not otherwise build storage facilities or hold sufficient strategic stocks, consistent with statutory authorities.

★ The NEPD Group recommends that the President, at such time that exchanged SPR barrels are returned to the SPR, should determine whether offshore Gulf of Mexico royalty oil deposits to the SPR should be resumed, thereby increasing the size of our reserve.

★ The NEPD Group recommends that the President direct the Secretary of Energy to work closely with Congress to ensure that our SPR protection is maintained.

★ The NEPD Group recommends that the President direct the Secretary of Energy to work with producer and consumer country allies and the IEA to craft a more compre hensive and timely world oil data reporting system.

CHAPTER ONE
Taking Stock: Energy Challenges Facing the United States

★ The NEPD Group recommends that the President issue an Executive Order to direct all federal agencies to include in any regulatory action that could significantly and adversely affect energy supplies, distribution, or use, a detailed statement on: (1) the energy impact of the proposed action, (2) any adverse energy effects that cannot be avoided should the proposal be implemented, and (3) alternatives to the proposed action. The agencies would be directed to include this statement in all submissions to the Office of Management and Budget of proposed regulations covered by Executive Order 12866, as well as in all notices of proposed regulations published in the Federal Register.

★ The NEPD Group recommends that the President direct the executive agencies to work closely with Congress to implement the legislative components of a national energy policy.

★ The NEPD Group recommends to the President that the NEPD Group continue to work and meet on the implementation of the National Energy Policy and explore other ways to advance dependable, affordable, and environmentally responsible production and distribution of energy.

Note: All recommendations in this report are subject to execution in accordance with applicable law. Legislation would be sought where needed. Also, any recommendations that involve foreign countries would be executed in accordance with the customs of international relations, including appropriate diplomatic consultation.

CHAPTER TWO
Striking Home The Impacts of High Energy Prices on Families, Communities, and Businesses

★ The NEPD Group recommends that the President direct the Secretary of Energy to ex plore potential opportunities to develop educational programs related to energy develop ment and use. This should include possible legislation to create public education aware ness programs about energy. Such programs should be long-term in nature, should be funded and managed by the respective energy industries, and should include information on energy's compatibility with a clean environment.

★ The NEPD Group recommends that the President take steps to mitigate impacts of high energy costs on low-income consumers. These steps would include:

- Strengthening the Low Income Home Energy Assistance Program by making $1.7 bil lion available annually. This is an increase of $300 million over the regular FY 2001 ap propriation.
- Directing the Secretaries of Interior and Health and Human Services to propose legis lation to bolster LIHEAP funding by using a portion of oil and gas royalty payments.
- Redirecting royalties above a set trigger price to LIHEAP, whenever crude oil and natural gas prices exceed that trigger price, as determined by the responsible agencies.

★ The NEPD Group recommends that the President increase funding for the Weatheriza tion Assistance Program by $1.2 billion over ten years. This will roughly double the spend ing during that period on weatherization. Consistent with that commitment, the FY 2002 Budget includes a $120 million increase over 2001. The Department of Energy will have the option of using a portion of those funds to test improved implementation approaches for the weatherization program.

★ The NEPD Group recommends that the President support legislation to allow funds dedicated for the Weatherization and State Energy Programs to be transferred to LIHEAP if the Department of Energy deems it appropriate.

★ The NEPD Group recommends the President recognize unique regional energy con cerns by working with the National Governors Association and regional governor associa tions to determine how to better serve the needs of diverse areas of the country.

★ The NEPD Group recommends the President direct FEMA to prepare for potential en ergy emergencies.

- FEMA should work with states' Offices of Emergency Management as they expand existing emergency operations plans to identify potential problems and address conse quences of the power shortages. FEMA should use its current Regional Incident Re porting System to identify any situations that might demand immediate attention.
- Using the structure of the already existing Federal Response Plan, FEMA should con duct Regional Interagency Steering Committee (RISC) meetings for states affected by the energy shortfalls. The RISC is a FEMA-led interagency committee comprised of agencies and departments that support the Federal Response Plan. Either an upcom ing, scheduled RISC meeting or a special-focus RISC meeting can be held to identify the short-term energy outlook, as well as any expected consequences, in each of the states during the peak summer season.

CHAPTER THREE

Protecting America's Environment: Sustaining the Nation's Health and Environment

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to propose multi-pollutant legislation. The NEPD Group recommends that the President direct the EPA Administrator to work with Congress to propose legislation that would establish a flexible, market-based program to significantly reduce and cap emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power generators. Such a program (with appropriate measures to address local concerns) would provide significant public health benefits even as we increase electricity supplies.

- Establish mandatory reduction targets for emissions of three main pollutants: sulfur dioxide, nitrogen oxides, and mercury.
- Phase in reductions over a reasonable period of time, similar to the successful acid rain reduction program established by the 1990 amendments to the Clean Air Act.
- Provide regulatory certainty to allow utilities to make modifications to their plants without fear of new litigation.
- Provide market-based incentives, such as emissions trading credits to help achieve the required reductions.

★ The NEPD Group recommends the President direct the Secretary of the Interior to work with Congress to create the "Royalties Conservation Fund."

- This fund will earmark potentially billions of dollars in royalties from new oil and gas production in ANWR to fund land conservation efforts.
- This fund will also be used to eliminate the maintenance and improvements backlog on federal lands.

★ The NEPD Group recommends the President issue an Executive Order to rational ize permitting for energy production in an environmentally sound manner by directing federal agencies to expedite permits and other federal actions necessary for energy related project approvals on a national basis. This order would establish an inter agency task force chaired by the Council on Environmental Quality to ensure that federal agencies responsible for permitting energy-related facilities are coordinating their efforts. The task force will ensure that federal agencies set up appropriate mechanisms to coordinate federal, state, tribal, and local permitting activity in particu lar regions where increased activity is expected.

CHAPTER FOUR
Using Energy Wisely: Increasing Energy Conservation and Efficiency

★ The NEPD Group recommends that the President direct the Office of Science and Technology Policy and the President's Council of Advisors on Science and Technology to review and make recommendations on using the nation's energy resources more effi ciently.

★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of energy efficiency re search and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.

★ The NEPD Group recommends that the President direct the Secretary of Energy to promote greater energy efficiency.

- Expand the Energy Star program beyond office buildings to include schools, re tail buildings, health care facilities, and homes.
- Extend the Energy Star labeling program to additional products, appliances, and services.
- Strengthen Department of Energy public education programs relating to energy efficiency.

★ The NEPD Group recommends that the President direct the Secretary of Energy to improve the energy efficiency of appliances.

- Support the appliance standards program for covered products, setting higher standards where technologically feasible and economically justified.
- Expand the scope of the appliance standards program, setting standards for ad ditional appliances where technologically feasible and economically justified.

★ The NEPD Group recommends that the President direct heads of executive depart ments and agencies to take appropriate actions to conserve energy use at their facilities to the maximum extent consistent with the effective discharge of public responsibili ties. Agencies located in regions where electricity shortages are possible should con serve especially during periods of peak demand. Agencies should report to the Presi dent, through the Secretary of Energy, within 30 days on the conservation actions taken.

★ The NEPD Group recommends that the President direct the Secretary of the Trea sury to work with Congress to encourage increased energy efficiency through combined heat and power (CHP) projects by shortening the depreciation life for CHP projects or providing investment tax credits.

★ The NEPD Group recommends that the President direct the Administrator of the En vironmental Protection Agency (EPA) to work with local and state governments to pro mote the use of well-designed CHP and other clean power generation at brownfields sites, consistent with the local communities' interests. EPA will also work to clarify li ability issues if they are raised at a particular site.

CHAPTER FOUR

★ The NEPD Group recommends that the President direct the EPA Administrator to promote CHP through flexibility in environmental permitting.

★ The NEPD Group recommends that the President direct the Secretary of Transporta tion to:

- Review and provide recommendations on establishing Corporate Average Fuel Economy (CAFE) standards with due consideration of the National Academy of Sciences study to be released in July 2001. Responsibly crafted CAFE standards should increase efficiency without negatively impacting the U.S. automotive indus try. The determination of future fuel economy standards must therefore be ad dressed analytically and based on sound science.
- Consider passenger safety, economic concerns, and disparate impact on the U.S. versus foreign fleet of automobiles.
- Look at other market-based approaches to increasing the national average fuel economy of new motor vehicles.

★ The new NEPD Group recommends that the President direct the Secretary of Trans portation to review and promote congestion mitigation technologies and strategies and work with Congress on legislation to implement these strategies.

★ The NEPD Group recommends that the President direct the Secretary of the Trea sury to work with Congress on legislation to increase energy efficiency with a tax credit for fuel-efficient vehicles. The NEPD Group recommends that a temporary, efficiency based income tax credit be available for purchase of new hybrid fuel cell vehicles be tween 2002 and 2007.

★ The NEPD Group recommends that the President direct all agencies to use techno logical advances to better protect our environment.

- The Administration remains committed to investing in Intelligent Transportation Systems (ITS) and encourages the private sector to invest in ITS applications. This Department of Transportation (DOT) program funds the development of improved transportation infrastructure that will reduce congestion, such as trav eler information/navigation systems, freeway management, and electronic toll collection. ITS applications reduce fuel associated with travel.
- The Administration remains committed to the DOT's fuel-cell-powered transit bus program, authored by the Transportation Equity Act for the 21st Century (TEA-21). This program demonstrates the viability of fuel-cell power plants for transit bus applications.
- The Administration remains committed to the Clean Buses program. TEA-21 es tablishes a new clean fuel formula grant program, which provides an opportu nity to accelerate the introduction of advanced bus propulsion technologies into the mainstream of the nation's transit fleet.

★ The NEPD Group recommends that the President direct the EPA and DOT to develop ways to reduce demand for petroleum transportation fuels by working with the trucking industry to establish a program to reduce emissions and fuel consumption from long-haul trucks at truck stops by implementing alternatives to idling, such as electrification and auxiliary power units at truck stops along interstate highways. EPA and DOT will develop partnership agreements with trucking fleets, truck stops, and manufacturers of idle-reducing technologies (*e.g.*, portable auxiliary packs, electrification) to install and use low emission-idling technologies.

★ The NEPD Group recommends that the President direct the Secretary of Energy to establish a national priority for improving energy efficiency. The priority would be to improve the energy intensity of the U.S. economy as measured by the amount of energy required for each dollar of economic productivity. This increased efficiency should be pursued through the combined efforts of industry, consumers, and federal, state, and local governments.

★ The NEPD Group recommends that the President direct the EPA Administrator to develop and implement a strategy to increase public awareness of the sizable savings that energy efficiency offers to homeowners across the country. Typical homeowners can save about 30 percent (about $400) a year on their home energy bill by using Energy Star labeled products.

Chapter Five Energy for a New Century: Increasing Domestic Energy Supplies

★ The NEPD Group recommends that the President direct the Secretaries of Energy and the Interior to promote enhanced oil and gas recovery from existing wells through new technology.

★ The NEPD Group recommends that the President direct the Secretary of Energy to improve oil and gas exploration technology through continued partnership with public and private entities.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to examine land status and lease stipulation impediments to federal oil and gas leasing, and review and modify those where opportunities exist (consistent with the law, good environmental practice, and balanced use of other resources).

- Expedite the ongoing Energy Policy and Conservation Act study of impediments to federal oil and gas exploration and development.
- Review public lands withdrawals and lease stipulations, with full public consultation, especially with the people in the region, to consider modifications where appropriate.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider economic incentives for environmentally sound offshore oil and gas development where warranted by specific circumstances: explore opportunities for royalty reductions, consistent with ensuring a fair return to the public where warranted for enhanced oil and gas recovery; for reduction of risk associated with production in frontier areas or deep gas formations; and for development of small fields that would otherwise be uneconomic.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Interior to re-examine the current federal legal and policy regime (statutes, regulations, and Executive Orders) to determine if changes are needed regarding energy-related activities and the siting of energy facilities in the coastal zone and on the Outer Continental Shelf (OCS).

★ The NEPD Group recommends that the President direct the Secretary of the Interior continue OCS oil and gas leasing and approval of exploration and development plans on predictable schedules.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider additional environmentally responsible oil and gas development, based on sound science and the best available technology, through further lease sales in the National Petroleum Reserve-Alaska. Such consideration should include areas not currently leased within the Northeast corner of the Reserve.

★ The NEPD Group recommends that the President direct the Secretary of the Interior work with Congress to authorize exploration and, if resources are discovered, development of the 1002 Area of ANWR. Congress should require the use of the best available technology and should require that activities will result in no significant adverse impact to the surrounding environment.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress and the State of Alaska to put in place the most expeditious process for renewal of the Trans-Alaska Pipeline System rights-of-way to ensure that Alaskan oil continues to flow uninterrupted to the West Coast of the United States.

★ The NEPD Group recommends that the President direct the Secretary of Energy to propose comprehensive electricity legislation that promotes competition, protects consumers, enhances reliability, promotes renewable energy, improves efficiency repeals the Public Utility Holding Company Act, and reforms the Public Utility Regulatory Policies Act.

★ The NEPD Group recommends that the President encourage FERC to use its existing statutory authority to promote competition and encourage investment in transmission facilities.

★ The NEPD Group recognizes the importance of looking to technology to help us meet the goals of increasing electricity generation while protecting our environment. To that end, the NEPD Group recommends that the President direct the Department of Energy to continue to develop advanced clean coal technology by:

- Investing $2 billion over 10 years to fund research in clean coal technologies.
- Supporting a permanent extension of the existing research and development tax credit.
- Directing federal agencies to explore regulatory approaches that will encourage advancements in environmental technology.

★ The NEPD Group recommends that the President direct federal agencies to provide greater regulatory certainty relating to coal electricity generation through clear policies that are easily applied to business decisions.

★ The NEPD Group recommends that the President support the expansion of nuclear energy in the United States as a major component of our national energy policy. Following are specific components of the recommendation:

- Encourage the Nuclear Regulatory Commission (NRC) to ensure that safety and environmental protection are high priorities as they prepare to evaluate and expedite applications for licensing new advanced-technology nuclear reactors.
- Encourage the NRC to facilitate efforts by utilities to expand nuclear energy generation in the United States by uprating existing nuclear plants safely.
- Encourage the NRC to relicense existing nuclear plants that meet or exceed safety standards.
- Direct the Secretary of Energy and the Administrator of the Environmental Protection Agency to assess the potential of nuclear energy to improve air quality.
- Increase resources as necessary for nuclear safety enforcement in light of the potential increase in generation.
- Use the best science to provide a deep geologic repository for nuclear waste.
- Support legislation clarifying that qualified funds set aside by plant owners for eventual decommissioning will not be taxed as part of the transaction.
- Support legislation to extend the Price–Anderson Act.

★ The NEPD Group recommends that, in the context of developing advanced nuclear fuel cycles and next generation technologies for nuclear energy, the United States should reexamine its policies to allow for research, development and deployment of fuel conditioning methods (such as pyroprocessing) that reduce waste streams and enhance proliferation resistance. In doing so, the United States will continue to discourage the accumulation of separated plutonium, worldwide.

★ The United States should also consider technologies (in collaboration with international partners with highly developed fuel cycles and a record of close cooperation) to develop reprocessing and fuel treatment technologies that are cleaner, more efficient, less waste intensive, and more proliferation-resistant.

CHAPTER FIVE

★ The NEPD Group recognizes there is a need to reduce the time and cost of the hydro power licensing process. The NEPD Group recommends that the President encourage the Federal Energy Regulatory Commission (FERC) and direct federal resource agencies to make the licensing process more clear and efficient, while preserving environmental goals. In addi tion, the NEPD Group recognizes the importance of optimizing the efficiency and reliability of existing hydropower facilities and will encourage the Administration to adopt efforts to ward that end.

- Support administrative and legislative reform of the hydropower licensing process.
- Direct federal resource agencies to reach interagency agreement on conflicting manda tory license conditions before they submit their conditions to FERC for inclusion in a license.
- Encourage FERC to adopt appropriate deadlines for its own actions during the licensing process.

CHAPTER SIX
Nature's Power: Increasing America's Use of Renewable and Alternative Energy

★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to re-evaluate access limitations to federal lands in order to increase renewable energy production, such as biomass, wind, geothermal, and solar.

★ The NEPD Group supports the increase of $39.2 million in the FY 2002 budget amendment for the Department of Energy's Energy Supply account that would provide increased support for research and development of renewable energy re sources.

★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of renewable energy and alternative energy research and development programs in light of the recommen dations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to expand the section 29 tax credit to make it available for new landfill methane projects. The credit could be tiered, de pending on whether a landfill is already required by federal law to collect and flare its methane emissions due to local air pollution concerns.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to determine ways to reduce the delays in geothermal lease processing as part of the permitting review process.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to develop a new renewable energy partnership program to help companies more easily buy renewable energy, as well as receive recognition for the environmental benefits of their purchase, and help consumers by promoting consumer choice programs that increase their knowledge about the environmental benefits of purchasing renewable energy.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to extend and expand tax credits for electricity produced using wind and biomass. The President's budget request extends the present 1.7 cents per kilowatt hour tax credit for electricity produced from wind and biomass; expands eligible biomass sources to include forest-related sources, agricultural sources, and certain urban sources; and allows a credit for electricity produced from biomass co-fired with coal.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to provide a new 15 percent tax credit for residential solar energy property, up to a maximum credit of $2,000.

★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to work with Congress on legislation to use an estimated $1.2 billion of bid bonuses from the environmentally responsible leasing of ANWR for funding research into alternative and renewable energy resources, including wind, solar, geothermal, and biomass.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to continue the ethanol excise tax exemption.

CHAPTER SIX

★ The NEPD Group recommends that the President direct the Secretary of Energy to develop next-generation technology—including hydrogen and fusion.

- Develop an education campaign that communicates the benefits of alternative forms of energy, including hydrogen and fusion.
- Focus research and development efforts on integrating current programs regarding hydrogen, fuel cells, and distributed energy.
- Support legislation reauthorizing the Hydrogen Energy Act.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to develop legislation to provide for a temporary income tax credit available for the purchase of new hybrid or fuel-cell vehicles between 2002 and 2007.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to issue guidance to encourage the development of well-designed combined heat and power (CHP) units that are both highly efficient and have low emissions. The goal of this guidance would be to shorten the time needed to obtain each permit, provide certainty to industry by ensuring consistent implementation across the country, and encourage the use of these cleaner, more efficient technologies.

CHAPTER SEVEN
America's Energy Infrastructure: A Comprehensive Delivery System

★ The NEPD Group recommends that the President direct the Secretary of Energy to work with the Federal Energy Regulatory Commission (FERC) to improve the reliabil ity of the interstate transmission system and to develop legislation providing for en forcement by a self-regulatory organization subject to FERC oversight.

★ The NEPD Group recommends that the President direct the Secretary of Energy to expand the Department's research and development on transmission reliability and superconductivity.

★ The NEPD Group recommends that the President direct the Secretary of Energy to au thorize the Western Area Power Administration to explore relieving the "Path 15" bottle neck through transmission expansion financed by nonfederal contributions.

★ The NEPD Group recommends that the President direct the appropriate federal agencies to take actions to remove constraints on the interstate transmission grid and allow our nation's electricity supply to meet the growing needs of our economy.

- Direct the Secretary of Energy, by December 31, 2001, to examine the benefits of establishing a national grid, identify transmission bottlenecks, and identify mea sures to remove transmission bottlenecks.
- Direct the Secretary of Energy to work with FERC to relieve transmission con straints by encouraging the use of incentive rate-making proposals.
- Direct the federal utilities to determine whether transmission expansions are nec essary to remove constraints. The Administration should review the Bonneville Power Administration's (BPA's) capital and financing requirements in the context of its membership in a regional RTO, and if additional Treasury financing appears war ranted or necessary in the future, the Administration should seek an increase in BPA's borrowing authority at that time.
- Direct the Secretary of Energy, in consultation with appropriate federal agencies and state and local government officials, to develop legislation to grant authority to obtain rights-of-way for electricity transmission lines, with the goal of creating a re liable national transmission grid. Similar authority already exists for natural gas pipelines in recognition of their role in interstate commerce.

★ The NEPD Group recommends that the President direct the Secretary of the Inte rior to work with Congress and the State of Alaska to put in place the most expedi tious process for renewal of the Trans-Alaskan Pipeline System lease to ensure that Alaskan oil continues to flow uninterrupted to the West Coast of the United States.

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that may be required.

★ The NEPD Group recommends that the President support legislation to improve the safety of natural gas pipelines, protect the environment, strengthen emergency preparedness and inspections and bolster enforcement.

CHAPTER SEVEN

★ The NEPD Group recommends that the President direct agencies to continue their interagency efforts to improve pipeline safety and expedite pipeline permitting in an environmentally sound manner and encourage FERC to consider improvements in the regulatory process governing approval of interstate natural gas pipeline projects.

★ The NEPD Group recommends that the President direct the Administrator of the EPA to study opportunities to maintain or improve the environmental benefits of state and local "boutique" clean fuel programs while exploring ways to increase the flexibility of the fuels distribution infrastructure, improve fungibility, and provide added gasoline market liquidity. In concluding this study, the Administrator shall con sult with the Departments of Energy and Agriculture, and other agencies as needed.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency and the Secretary of Energy to take steps to ensure America has adequate refining capacity to meet the needs of consumers.

- Provide more regulatory certainty to refinery owners and streamline the permitting process where possible to ensure that regulatory overlap is limited.
- Adopt comprehensive regulations (covering more than one pollutant and require ment) and consider the rules' cumulative impacts and benefits.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency, in consultation with the Secretary of Energy and other relevant agencies, to review New Source Review regulations, including adminis trative interpretation and implementation, and report to the President within 90 days on the impact of the regulations on investment in new utility and refinery generation capacity, energy efficiency, and environmental protection.

★ The NEPD Group recommends that the President direct the Attorney General to review existing enforcement actions regarding New Source Review to ensure that the enforcement actions are consistent with the Clean Air Act and its regulations.

★ The NEPD Group supports the President's budget proposal to provide $8 million to maintain the two-million-barrel Northeast Heating Oil Reserve. Operated by the pri vate sector, the Reserve helps ensure adequate supplies of heating oil in the event that colder than normal winters occur in the Northeast United States.

CHAPTER 8
Strengthening Global Alliances: Enhancing National Energy Security and International Relationships

★ The NEPD Group recommends that the President make energy security a priority of our trade and foreign policy.

★ The NEPD Group recommends the President support initiatives by Saudi Arabia, Ku wait, Algeria, Qatar, the UAE, and other suppliers to open up areas of their energy sec tors to foreign investment.

★ The NEPD Group recommends that the President direct the Secretaries of State, En ergy and Commerce work to improve dialogue among energy producing and consuming nations.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to continue supporting American energy firms competing in markets abroad and use our membership in multilateral organizations, such as the Asia-Pacific Economic Cooperation (APEC) forum, the Organization for Economic Coopera tion and Development (OECD), the World Trade Organization (WTO) Energy Services Negotiations, the Free Trade Area of the Americas (FTAA), and our bilateral relation ships to implement a system of clear, open, and transparent rules and procedures gov erning foreign investment; to level the playing field for U.S. companies overseas; and to reduce barriers to trade and investment.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Energy, and the U.S. Trade Representative, to support a sectoral trade initiative to expand investment and trade in energy-related goods and services that will enhance ex ploration, production, and refining, as well as the development of new technologies.

★ The NEPD Group recommends that the President direct the Secretaries of State, Treasury, and Commerce to initiate a comprehensive review of sanctions. Energy securi ty should be one of the factors considered in such a review.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to engage in a dialogue through the North American Energy Working Group to develop closer energy integration among Canada, Mexico, and the United States and identify areas of cooperation, fully consistent with the countries' re spective sovereignties.

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, in consultation with the Federal Energy Regulatory Commission, to review their respective oil, natural gas, and electricity cross-boundary "Presidential Permitting" authorities, and to propose reforms as necessary in order to make their own regulatory regimes more compatible for cross-border trade.

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that

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may be required.

★ The NEPD Group recommends that the President direct the Secretaries of State and Commerce to conclude negotiations with Venezuela on a Bilateral Investment Treaty, and propose formal energy consultations with Brazil, to improve the energy investment climate for the growing level of energy investment flows between the United States and each of these countries.

★ The NEPD Group recommends that the President direct the Secretaries of Energy, Commerce, and State to work through the Summit of the Americas Hemispheric Ener gy Initiative to develop effective and stable regulatory frameworks and foster reliable supply sources of all fuels within the region.

★ The NEPD Group recommends that the President direct the Secretaries of State, En ergy, and Commerce to reinvigorate the U.S.-Africa Trade and Economic Cooperation Forum and the U.S.-African Energy Ministerial process; deepen bilateral and multilater al engagement to promote a more receptive environment for U.S. oil and gas trade, in vestment, and operations; and promote geographic diversification of energy supplies, addressing such issues as transparency, sanctity of contracts, and security.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support more transparent, accountable, and responsible use of oil resources in African producer countries to enhance the stability and security of trade and investment environments.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the BTC oil pipeline as it demonstrates its commer cial viability.

★ The NEPD Group recommends that the President direct the Secretaries of Com merce, State, and Energy to continue working with relevant companies and countries to establish the commercial conditions that will allow oil companies operating in Kaza khstan the option of exporting their oil via the BTC pipeline.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the efforts of private investors and regional govern ments to develop the Shah Deniz gas pipeline as a way to help Turkey and Georgia di versify their natural gas supplies and help Azerbaijan export its gas via a pipeline that will continue diversification of secure energy supply routes.

★ The NEPD Group recommends that the President direct appropriate federal agen cies to complete the current cycle of oil spill response readiness workshops and to consider further appropriate steps to ensure the implementation of the workshops' rec ommendations.

★ The NEPD Group recommends that the President direct the Secretary of State to en courage Greece and Turkey to link their gas pipeline systems to allow European con sumers to diversify their gas supplies by purchasing Caspian gas.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, Energy, and State to deepen their commercial dialogue with Kazakhstan, Azerbaijan, and other Caspian states to provide a strong, transparent, and stable business climate for energy and related infrastructure projects.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to deepen the focus of the discussions with Russia on energy and the investment climate.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to assist U.S. companies in their dialogue on the investment and trade climate with Russian officials, to encourage reform of the PSA law and other regulations and related tax provisions, as well as general improvements in the overall investment climate. This will help expand private investment opportunities in Russia and will increase the international role of Russian firms.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to continue to work in the APEC Energy Working Group to examine oil market data transparency issues and the variety of ways petroleum stocks can be used as an option to address oil market disruptions.

★ The NEPD Group recommends that the President direct the Secretaries of State and Energy to work with India's Ministry of Petroleum and Natural Gas to help India maximize its domestic oil and gas production.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to promote market-based solutions to environmental concerns; support exports of U.S. clean energy technologies and encourage their overseas development; engage bilaterally and multilaterally to promote best practices; explore collaborative international basic research and development in energy alternatives and energy-efficient technologies; and explore innovative programs to support the global adoption of these technologies.

★ The NEPD Group recommends that the President direct federal agencies to support continued research into global climate change; continue efforts to identify environmentally and cost-effective ways to use market mechanisms and incentives; continue development of new technologies; and cooperate with allies, including through international processes, to develop technologies, market-based incentives, and other innovative approaches to address the issue of global climate change.

★ The NEPD Group recommends that the President seek to increase international cooperation on finding alternatives to oil, especially for the transportation sector.

★ The NEPD Group recommends that the President direct the Secretary of State to reinvigorate its dialogue with the European Union on energy issues, and resume the consultative process this year in Washington.

★ The NEPD Group recommends that the President promote a coordinated approach to energy security by calling for an annual meeting of G-8 Energy Ministers or their equivalents.

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★ The NEPD Group recommends that the President reaffirm that the SPR is designed for addressing an imminent or actual disruption in oil supplies, and not for managing prices.

★ The NEPD Group recommend that the President direct the Secretary of Energy to work within the International Energy Agency (IEA) to ensure that member states ful fill their stockholding.

★ The NEPD Group recommends that the President direct the Secretary of Energy to encourage major oil-consuming countries that are not IEA members to consider stra tegic stocks as an option for addressing potential supply disruptions. In this regard, we should work closely with Asian economies, especially through APEC.

★ The NEPD Group recommends that the President direct the Secretary of Energy of fer to lease excess SPR storage facilities to countries (both IEA and non-IEA mem bers) that might not otherwise build storage facilities or hold sufficient strategic stocks, consistent with statutory authorities.

★ The NEPD Group recommends that the President, at such time that exchanged SPR barrels are returned to the SPR, should determine whether offshore Gulf of Mexi co royalty oil deposits to the SPR should be resumed, thereby increasing the size of our reserve.

★ The NEPD Group recommends that the President direct the Secretary of Energy to work closely with Congress to ensure that our SPR protection is maintained.

★ The NEPD Group recommends that the President direct the Secretary of Energy to work with producer and consumer country allies and the IEA to craft a more compre hensive and timely world oil data reporting system.

Glossary

Barrel (Oil): A unit of volume equal to 42 U.S. gallons.

Barrels per Day (Operable Refinery Capacity): The maximum number of barrels of in put that can be processed during a 24-hour period after making allowances for the following limitations: the capability of downstream facilities to absorb the output of crude oil process ing facilities of a given refinery (no reduction is made when a planned distribution of inter mediate streams through other than downstream facilities is part of a refinery's normal op eration); the types and grades of inputs to be processed; the types and grades of products to be manufactured; the environmental constraints associated with refinery operations; the re duction of capacity for scheduled downtime, such as routine inspection, mechanical prob lems, maintenance, repairs, and turnaround; and the reduction of capacity for unscheduled downtime, such as mechanical problems, repairs, and slowdowns.

Biomass: Organic nonfossil material of biological origin constituting a renewable energy source.

British Thermal Unit (Btu): The quantity of heat needed to raise the temperature of 1 pound of water by 1°F at or near 39.2°F.

Coal: A readily combustible black or brownish-black rock whose composition, including in herent moisture, consists of more than 50 percent by weight and more than 70 percent by volume of carbonaceous material. It is formed from plant remains that have been com pacted, hardened, chemically altered, and metamorphosed by heat and pressure over geo logic time.

Cogeneration: The production of electricity and another form of useful energy (such as heat or steam) used for industrial, commercial, heating, or cooling purposes.

Commercial Building: A building with more than 50 percent of its floor space used for commercial activities. Commercial buildings include stores, offices, schools, churches, gym nasiums, libraries, museums, hospitals, clinics, warehouses, and jails. Government buildings are also included, except buildings on military bases or reservations.

Commercial Sector: Business establishments that are not engaged in transportation or in manufacturing or other types of industrial activity (agriculture, mining, or construction). Commercial establishments include hotels, motels, restaurants, wholesale businesses, retail stores, laundries, and other service enterprises; religious and nonprofit organizations; health, social, and educational institutions; and federal, state, and local governments. Streetlights, pumps, bridges, and public services are also included if the establishment oper ating them is considered commercial.

Conversion Factor: A number that translates units of one system into corresponding val ues of another system. Conversion factors can be used to translate physical units of mea sure for various fuels into Btu equivalents.

Crude Oil: A mixture of hydrocarbons that exists in liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separat ing facilities. Crude oil may also include:

- Small amounts of hydrocarbons that exist in the gaseous phase in natural under ground reservoirs but are liquid at atmospheric pressure after being recovered from oil well (casing head) gas in lease separators and that subsequently are commingled with the crude stream without being separately measured.
- Small amounts of nonhydrocarbons produced with the oil, such as sulfur and other compounds

Crude Oil Stocks: Stocks of crude oil and lease condensate held at refineries, in pipelines, at pipeline terminals, and on leases.

District Heat: Steam or hot water from an outside source used as an energy source in a building. The steam or hot water is produced in a central plant and is piped into the build ing. District heat may be purchased from a utility or provided by a physical plant in a sepa rate building that is part of the same facility (for example, a hospital complex or university).

Electric Power Plant: A station containing prime movers, electric generators, and auxil iary equipment for converting mechanical, chemical, and/or fission energy into electric en ergy.

Electricity Generation: The process of producing electric energy or transforming other forms of energy into electric energy. Also, the amount of electric energy produced or ex pressed in watt-hours (Wh).

End-Use Sectors: The residential, commercial, industrial, and transportation sectors of the economy.

Energy: The capacity for doing work as measured by the capability of doing work (poten tial energy), or the conversion of this capability to motion (kinetic energy). Energy has sev eral forms, some of which are easily convertible and can be changed to another form useful for work. Most of the world's convertible energy comes from fossil fuels that are burned to produce heat that is then used as a transfer medium to mechanical or other means in order to accomplish tasks. Electrical energy is usually measured in kilowatt-hours, while heat en ergy is usually measured in British thermal units.

Energy Consumption: The use of energy as a source of heat or power or as an input in the manufacturing process.

Energy Source: A substance, such as oil, natural gas, or coal, that supplies heat or power. Electricity and renewable forms of energy, such as wood, waste, geothermal, wind, and so lar, are considered to be energy sources.

Exports: Shipments of goods from the 50 states and the District of Columbia to foreign countries and to Puerto Rico, the Virgin Islands, and other U.S. possessions and territories.

Federal Energy Regulatory Commission (FERC): The federal agency with jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification. FERC is an independent regulatory agency within the Department of Energy and is the successor to the Federal Power Com mission.

Fossil Fuel: Any naturally occurring organic fuel formed in the Earth's crust, such as oil, coal, and natural gas.

Fuel Ethanol: An anhydrous, denatured aliphatic alcohol intended for motor gasoline blending.

Gas-Turbine Electric Power Plant: A plant in which the prime mover is a gas turbine. A gas turbine typically consists of an axial-flow air compressor and one or more combustion chambers where liquid or gaseous fuel is burned. The hot gases expand to drive the genera tor and then are used to run the compressor.

Geothermal Energy: Energy from the internal heat of the Earth, which may be residual heat, friction heat, or a result of radioactive decay. The heat is found in rocks and fluids at various depths and can be extracted by drilling or pumping.

Gross Domestic Product (GDP): The total value of goods and services produced by la bor and property located in the United States.

Hydrocarbon: An organic chemical compound of hydrogen and carbon in the gaseous, liq uid, or solid phase. The molecular structure of hydrocarbon compounds varies from the simplest (methane, a constituent of natural gas) to the very heavy and very complex.

Hydropower: The production of electricity from the kinetic energy of falling water.

Hydropower Plant: A plant in which the turbine generators are driven by falling water.

Independent Power Producer: Wholesale electricity producers (other than qualifying fa cilities under the Public Utilities Regulatory Policies Act of 1978) that are unaffiliated with franchised utilities in the area in which the independent power producers are selling power and that lack significant marketing power. Unlike traditional electric utilities, independent power producers do not possess transmission facilities that are essential to their customers and do not sell power in any retail service territory where they have a franchise.

Industrial Sector: Manufacturing industries, which make up the largest part of the sector, along with mining, construction, agriculture, fisheries, and forestry. Establishments in this sector range from steel mills, to small farms, to companies assembling electronic compo nents.

Jet Fuel: A refined petroleum product used in jet aircraft engines. It includes kerosene type jet fuel and naphtha-type jet fuel.

Methane: Hydrocarbon gas, which is the major component of natural gas.

Methanol: A light, volatile alcohol eligible for motor gasoline blending.

Methyl Tertiary Butyl Ether (MTBE): An ether, intended for motor gasoline blending.

Natural Gas: A gaseous mixture of hydrocarbon compounds, primarily methane, delivered via pipeline for consumption. It is used as a fuel for electricity generation, a variety of uses in buildings, and as raw material input and fuel for industrial processes. *Note*: This product, also referred to as *dry natural gas* or *consumer-grade natural gas*, is the product that re mains after *wet natural gas* has been processed at lease facilities and/or natural gas pro cessing plants. This processing removes nonhydrocarbon gases (e.g., water vapor, carbon dioxide, helium, hydrogen sulfide, and nitrogen) that would otherwise make the gas unmar ketable and natural gas liquids.

Natural Gas, Dry: The marketable portion of natural gas production, which is obtained by subtracting extraction losses, including natural gas liquids removed at natural gas process ing plants, from total production.

Natural Gas, Wet: A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in porous rock formations at reservoir conditions. The principal hydrocarbons normally contained in the mixture are methane, ethane, propane, butane, and pentanes. Typical nonhydrocarbon gases that may be present in reservoir natural gas are water vapor, carbon dioxide, helium, hydrogen sulfide, and nitrogen. Under reservoir conditions, natural gas and the liquefiable portions occur either in a single gaseous phase in the reservoir or in solution with oil and are not distinguishable at the time as separate substances.

Nitrogen Oxides (NOx): Compounds of nitrogen and oxygen produced by the burning of fossil fuels.

North American Electric Reliability Council (NERC): A council formed in 1968 by the electric utility industry to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America. The NERC consists of ten regional reliability councils and encompasses essentially all the power systems of the contiguous United States and Canada.

Nuclear Electric Power: Electricity generated by an electric power plant whose turbines are driven by steam generated in a reactor by heat from the fissioning of nuclear fuel.

Organization for Economic Cooperation and Development (OECD): Current mem bers are Australia, Austria, Belgium, Canada, Czech Republic, Denmark and its territories (Faroe Islands and Greenland), Finland, France, Germany, Greece, Greenland, Hungary, Iceland, Ireland, Italy, Japan, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Poland, Portugal, South Korea, Spain, Sweden, Switzerland, Turkey, United Kingdom, and United States and its territories (Guam, Puerto Rico, and Virgin Islands).

Organization of Petroleum Exporting Countries (OPEC): Countries that have orga nized for the purpose of negotiating with oil companies on matters of oil production, prices, and future concession rights. Current members are Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates, and Venezuela.

Photovoltaic Energy: Direct-current electricity generated from sunlight through solid state semiconductor devices that have no moving parts.

Pipeline, Natural Gas: A continuous pipe conduit, complete with such equipment as valves, compressor stations, communications systems, and meters, for transporting natural gas and/or supplemental gaseous fuels from one point to another, usually from a point in or beyond the producing field or processing plant to another pipeline or to points of use. Also refers to a company operating such facilities.

Pipeline, Oil: Oil and product pipelines (including interstate, intrastate, and intracompany pipelines) used to transport oil and petroleum products, respectively, within the 50 states and the District of Columbia.

Proved Reserves, Oil: The estimated quantities of all liquids defined as crude oil that geo logical and engineering data demonstrate with reasonable certainty to be recoverable in fu ture years from known reservoirs under existing economic and operating conditions.

Proved Reserves, Natural Gas: The estimated quantities of natural gas that analysis of geological and engineering data demonstrates with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Refinery (Oil): An installation that manufactures finished fuels from oil, unfinished oils, natural gas liquids, other hydrocarbons, and alcohol.

Renewable Energy: Energy obtained from sources that are essentially inexhaustible (un like, for example, fossil fuels, of which there is a finite supply). Renewable sources of en ergy include conventional hydroelectric power, wood, waste, geothermal, wind, photovol taic, and solar thermal energy.

Spot Price: The price for a one-time open market transaction for immediate delivery of the specific quantity of product at a specific location where the commodity is purchased “on the spot” at current market rates.

Strategic Petroleum Reserve (SPR): Petroleum stocks maintained by the federal gov ernment for use during periods of major supply interruption.

Stocks: Supplies of fuel or other energy source(s) stored for future use. Stocks are re ported as of the end of the reporting period.

Sulfur Dioxide (SO_2): A toxic, colorless gas soluble in water, alcohol, and ether. Used as a chemical intermediate in paper pulping and ore refining, and as a solvent.

Transportation Sector: Private and public vehicles that move people and commodities. Included are automobiles, trucks, buses, motorcycles, railroads, and railways (including streetcars), aircraft, ships, barges, and natural gas pipelines.

Wellhead Price: The price of oil or natural gas at the mouth of the well.

Wind Energy: The kinetic energy of wind converted into mechanical energy by wind tur bines (i.e., blades rotating from a hub) that drive generators to produce electricity.

Wood Energy: Wood and wood products used as fuel, including round wood (cord wood), limb wood, wood chips, bark, sawdust, forest residues, charcoal, pulp waste, and spent pulping liquor.


SEAL OF THE PRESIDENT OF THE UNITED STATES

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-29
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-30

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 140
MISO ERAS December Release

MISO announces second cycle of ERAS projects

6,100 MW of proposed capacity supports reliability, economic growth and regional energy needs

For Immediate Release

December 1, 2025

Media Contact

McKenzie Barbknecht

CARMEL, Ind. — MISO announced today the second cycle of projects to be evaluated under its Expedited Resource Addition Study (ERAS) process, reinforcing its commitment to accelerating the addition of critical generation resources across the region.

The second cycle includes 15 projects totaling approximately 6,100 MW of proposed new capacity. These projects span a range of fuel sources — including solar, wind, natural gas, and battery storage and are located across MISO's North, Central and South regions. The in-service dates range from December 1, 2027 to August 6, 2028.

"Cycle 2 builds on the momentum of Cycle 1 and reflects the continued demand for timely, reliable interconnection solutions," said Aubrey Johnson, MISO's Vice President, System Planning. "These projects are essential to meeting near-term reliability needs and ensuring new resource additions are online to meet load growth."

To date, 51 projects representing nearly 30,000 MW of proposed new capacity have been accepted or are pending validation into ERAS. Cycle 1 had 10 projects, representing approximately 5,300 MW of capacity. Three Cycle 1 projects already have executed generator interconnection agreements and the other seven will be completed in December. MISO evaluates each ERAS project for eligibility and completeness, and after FERC's recent approval MISO will study up to 15 projects per quarter. There is a program cap of 68 projects before ERAS sunsets on August 31, 2027.

"ERAS is one of several tools we're using to meet the evolving needs of our members and the communities they serve," added Johnson. "MISO remains focused on reducing timelines in our generator interconnection queue through the recently approved queue cap and through improved software automation."

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About MISO

Midcontinent Independent System Operator (MISO) is an independent, not-for-profit organization that delivers safe, cost-effective electric power across 15 U.S. states and the Canadian province of Manitoba. 42 million people depend on MISO to generate and transmit the right amount of electricity every minute of every day. MISO is committed to reliable, nondiscriminatory operation of the bulk power transmission system and collaborating with all stakeholders to create cost-effective and innovative solutions for our changing industry. MISO operates one of the world's largest energy markets with more than $22 billion in annual gross market energy transactions.

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