BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

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

Exhibit 2-110:
PacifiCorp 2024 URC RFP

2024 Utah Renewable Communities

Request for Proposals

"2024 URC RFP"

Program Renewable Resources

ISSUED: **5/22/2025**

DUE DATE: **7/10/2025**

2024 URC RFP Responses:

Energy Strategies, LLC
111 East Broadway, Suite 1200
Salt Lake City, Utah 84111
www.URC2024RFP.com

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Each of the Appendices referenced above are available at www.URC2024RFP.com. The 2024 URC RFP is utilizing Appendices from the PacifiCorp 2022 AS RFP to streamline the process for bidders that participated in the PacifiCorp 2022 AS RFP and to ensure that the Communities and PacifiCorp receive all of the information necessary for the Communities to evaluate and score the bids and for PacifiCorp to utilize in contracting.

However, the following appendices that were included in the PacifiCorp 2022 AS RFP are intentionally omitted from this solicitation:

- Appendix B-1 series: Notice of Intent to Bid, NOI Excel Spreadsheet, Bid Fee

Calculator Worksheet

- Appendix E-2.2: Co-located Generating Resource with Energy Storage
- Appendix E-3: Tolling Agreement Documents
- Appendix H-3: PacifiCorp Transmission: Summary of OASIS queue positions
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- Appendix H-2: PacifiCorp IRP Preferred Portfolio Proxy Resource Selections (update to reflect 2023 IRP Update)

The following appendices that were included in the PacifiCorp 2022 AS RFP have been updated for use in this solicitation:

- Appendix A-1.4: BTA Solar Work Specifications (updates to preferred and prohibited vendors)
- Appendix A-1.6: BTA Battery Energy Storage System Technical Specification (updates to preferred and prohibited vendors)

Additionally, the following appendices that were included in the PacifiCorp 2022 AS RFP are included in the URC 2024 RFP but contain substantively different questions, information, conditions, or signatories:

- Appendix B-2 Bid Proposal Instructions and Required Information
- Appendix C-1: Bid Summary and Pricing Input Sheet Instructions (revised)
- Appendix C-2: Bid Summary and Pricing Input Sheet (additional tabs and questions)
- Appendix E-2.1: PPA Documents – Generating Resource Only (additional conditions)
- Appendix F-2: BTA Documents (additional conditions)
- Appendix G-1: Confidentiality Agreement
- Appendix G-2: Non-Reliance Letter
- Appendix S: Cyber Security Requirements

Finally, one additional appendix that was not included in the PacifiCorp 2022 AS RFP has been added for use in this solicitation:

- Appendix W: Payment Instructions

As noted herein, the Communities are solely responsible for the administration of the 2024 URC RFP. PacifiCorp dba Rocky Mountain Power (Company) is not administering the 2024 URC RFP and the use of the PacifiCorp 2022 AS RFP is a convenience to the Communities, to Company, and to the bidders and does not signify any greater involvement from PacifiCorp than is described herein.

SECTION 1. INTRODUCTION

This 2024 Utah Renewable Communities' Request for Proposals for renewable energy resources (2024 URC RFP), is administered by the Community Renewable Energy Agency (Agency)[1] on behalf of customers that participate in the Community Clean Energy Program (Program).[2] The 2024 URC RFP is seeking cost-competitive bids for energy produced by wind, photovoltaic (PV) solar, geothermal, or hydroelectric resources and interconnecting with PacifiCorp's transmission system. The resources must meet the criteria developed by the Agency in conjunction with Company and set forth in this RFP. The Agency is seeking to purchase energy from renewable resources pursuant to the Community Clean Energy Act (Act (Utah Code §§ 54-17-901 to -909)) and in support of the Program created by the Act and the Utah Public Service Commission (Commission).

Proposals must demonstrate to the Agency's satisfaction, and as determined in its sole discretion, that the proposed project(s) can successfully interconnect and achieve commercial operation within the timeframe listed in Section 2. The Agency is not bound to accept any bids and may cancel this solicitation at any time and at their own discretion.

Bids must be for new generation capacity not located behind any load served by a utility or net-metered, and each project must be individually metered and remotely monitored. The project bid may be for the partial output of new generation capacity so long as all other contracted output is for customers in Rocky Mountain Power's service territory. The minimum discrete project size is 2.0 MW AC and the maximum is 300.0 MW AC, and the Agency is seeking a project or projects to meet 600,000 MWhs of average annual forecasted demand for customers participating in the Program (Participating Customers) in the project(s)' first full calendar year of operation.

The Agency will accept proposals for generation from new wind, photovoltaic (PV) solar, geothermal, or hydroelectric resource projects capable of directly interconnecting with Company's network transmission system. These resources are required to self-provide ancillary services to the grid and may be subject to curtailment to ensure sufficient self-provided ancillary service. Other resource types may be considered as required by the Commission so long as they meet the other requirements of this solicitation.

Each bid ***must*** include the Base Bid as described below. It may optionally include up to two add-ons and two variants, also described below.

The required "Base Bid" shall include the fixed price (in dollars per Megawatt-hour or $/MWh) at which the bidder proposes to sell all energy generated by the project to Company over a twenty-five (25) year term. This fixed price shall also include any and all environmental attributes associated with all energy generated, which will be transferred to and exclusively owned by the Agency on behalf of Participating Customers.[3] The Base Bid may not combine generation resource types and is required of all bidders.

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[1] The public-facing name of the Agency is the Utah Renewable Communities (URC).
[2] Additional information regarding the Agency, its formation and decision-making authority, is set forth in Section 3 below.
[3] "Environmental Attributes" will be a defined term in the pro forma transaction documents for this RFP.

In addition to the Base Bid, the bidder may optionally include the following two add-ons:

1. A "Storage Add-On" option specifying the price to co-locate storage with the generating resource, priced in dollars per kilowatt-month for a twenty-five (25) year term. The Storage Add-On may or may not be evaluated by the Agency for scoring purposes but may feature in contract negotiations. Should the Agency select a bid with a Storage Add-On for contract negotiation, parties will discuss whether to address the storage component with a combined generation and storage agreement (using Appendix E-2.2 from PacifiCorp's 2022 All-Source RFP as a starting point) or with a separate tolling agreement (using Appendix E-3 from PacifiCorp's 2022 All-Source RFP as a starting point).

2. A "Post-PPA Sale Add-On" option priced in dollars whereby the bidder proposes to sell its project rights to Company at the conclusion of the twenty-five (25) year PPA term. The Post-PPA Sale Add-On will not be evaluated by the Agency for scoring purposes but may feature in contract negotiations.

In addition to the Base Bid, the bidder may optionally include the following two bid variants:

1. A "Twenty Year Bid Variant" PPA option specifying a fixed priced (in $ per MWh) at which the bidder proposes to sell all energy generated by the project to Company over a twenty (20) year term that meets the other requirements of the Base Bid. The Twenty Year Bid Variant will not be evaluated by the Agency for scoring purposes but may feature in contract negotiations.

2. A "BTA Bid Variant" option priced in dollars whereby the bidder develops the generation project, assumes responsibility for construction and ultimately transfers the operating asset to Company prior to the Commercial Operation Date (COD), all pursuant to the terms of a build transfer agreement (BTA). Bidder is responsible for all development, design[4], generation equipment supply, balance of plant (BOP) equipment, construction, commissioning, and performance testing. A bidder that elects to submit the optional BTA Bid Variant must submit a price for the generation resource and may also submit a price for the generation resource plus co-located storage. These BTA prices will not be evaluated by the Agency for scoring purposes but if a Base Bid selected for contract negotiation by the Agency also includes the optional BTA Bid Variant, then Company may elect to pursue the BTA Bid Variant.

The Agency reserves the right to reject non-compliant bids. Only the Base Bid will be evaluated for Phase 2 evaluation. The Agency may elect to select a Base Bid with optional Storage Add-On for Phase 3 evaluation. During the negotiation phase described in Section 7(D), below, the Agency reserves the right to use the bid pricing to propose an equivalent

[4] The resource design must comply with Company's pro forma technical specification as identified in RFP Appendices.

two-phase PPA price, with a higher fixed price in the first 1-5 years and a commensurately lower fixed price for the remaining years during contract negotiations.

Importantly, a PPA signed by Company to serve a Program under the Act may contain additional conditions precedent to become effective. If a bid's price exceeds its modeled financial benefit, resulting in a net-cost, then the Program will likely need to provide a reserve fund covering a substantial share of this net-cost before the PPA can become effective. For this reason, the Phase 3 price evaluation (described in Section 6) considers both the net-cost of energy (in dollars per Megawatt-hour) and the net-cost of contract (in dollars). Bidders should be advised that, while the net-cost of energy (in dollars per Megawatt-hour) for larger projects (closer to the upper end of the 300 MW cap) may be superior to smaller projects, the net-cost of contract (in dollars) for larger projects may be inferior to smaller projects because of the reserve fund requirement described above.

While not currently reflected in **Appendix E-2.1 Power Purchase Agreement**, the Agency and PacifiCorp are exploring other potential security mechanisms for the program that may impact Appendix E-2.1, including termination provisions, should the Agency and PacifiCorp come to an agreement on a working mechanism.

For bids selected by the Agency for contract negotiation, the Agency may specify a share of the project's generation that may be separately contracted by a large energy user within Company's service territory.

Company and Agency may request from bidder (1) financial statements and/or (2) documentation from an independent engineer that supports the economic useful life of the underlying asset. Please see Section 4.C for more information related to Variable Interest Entity (VIE) accounting and tax ownership.

Pursuant to the Act and associated Commission rules, Company is required to obtain Commission approval prior to entering into any PPA or BTA selected in connection with this RFP, and execution of any such BTA or PPA is contingent on Company receiving such approval.

The Agency is not required to utilize an independent evaluator (IE) in conducting the RFP.

SECTION 2. PROCEDURAL ITEMS

Bids will be evaluated based on the following:

- Cost to Participating Customers.
- Project location.
- Project size.
- Project readiness, including site control, development status (including status for all permits), developer's experience, and demonstration that the project's commercial operation date will be achieved between January 1, 2026 and December 31, 2029.
- Transmission access and interconnection status in conformance with the 2024 URC RFP requirements outlined in Section 5.B. Direct Interconnection.

- Bidder must include Base Bid PPA pricing as described above.
- Exceptions to the pro forma PPA and BTA terms as represented in **Appendix E-2 and Appendix F-2** respectively. Note that any bids that include exceptions that significantly alter the structure of the pro forma Build-Transfer Agreement as described in Section 4.B of this RFP may be rejected as non-compliant without regard to any other evaluation factors.
- Compliance with and verification of major equipment availability defined in **Appendix A – Technical Specification,** and as outlined in **Appendices A-1 through A-10** for each type of renewable technology.
- Ability to provide acceptable credit security for the bidder's proposed obligation and conformance to the pro forma agreements attached as **Appendices E-2** and **F-2** to this RFP.

Each proposal will be prepared at the sole cost and expense of the bidder and with the express understanding that there will be no claims whatsoever for reimbursement from Company or the Agency. Neither the Agency nor Company is liable for any costs incurred by bidders in responding to this RFP, and bidder shall not be entitled to recover any damages arising out of or relating to the Agency's rejection of any proposal, or bidder's reliance upon any communication received from the Agency or from Company, for any reason. Bidder shall bear all costs, expenses, and bidder fees of any response to the Agency in connection with its proposal for the 2024 URC RFP, including providing additional information, the bidder fee, and bidder's own expenses in negotiating and reviewing any documentation. Bid fees are non-refundable in all circumstances, including in the event that no bids are selected or if the 2024 URC RFP is terminated. Additionally, winning bidder(s) may be required to provide a bidder success fee in the event bidder fees do not cover RFP administration and evaluation costs.

Appendix E-1 – PPA Instructions to bidder provides additional detail on preparation of bid document deliverables.

All proposals belong to the Agency and will not be returned. Confidentiality agreements and mutual nondisclosure agreements (NDAs) will be executed with Initial Short List projects as part of this RFP. The Agency will use reasonable efforts to protect information clearly and prominently marked as proprietary and confidential on the page it appears, but the Agency reserves the right to release such information to agents or contractors to help evaluate the proposal, as well as to Company, its regulators and non-bidding parties to regulatory proceedings subject to standard protective orders or confidentiality arrangements. The Agency shall not be liable for any damages resulting from any disclosure of such information, howsoever occurring.

Each bidder must submit a non-refundable bid fee as follows:

- for project bids of 10 MW or smaller: $5,000
- for project bids larger than 10 MW: $15,000

This bid fee will be required for each separate Base Bid. This bid fee will cover any associated optional add-ons (Storage Add-On, Post-PPA Sale Add-on) so long as the price for generation specified in the Base Bid remains constant. The bid fee will also cover any

associated optional Twenty-Year Bid Variant so long as the only difference from the Base Bid is the price for generation and the contract end date.

All optional bid add-ons and variants may not be evaluated by the Agency for scoring purposes. However, these optional elements may be evaluated by Agency or Company and may feature in contract negotiations.

Should a bid be selected for the Initial Short List for advancement to Phase 3 evaluation, PacifiCorp will require an additional $12,500 bid analysis fee, payable to PacifiCorp. Any variant upon the original bid will be submitted as a new bid and subject to the full bid fee of $12,500. The bid fee in support of Phase 3 is non-refundable should negotiations fail to produce an executed power purchase agreement. The bid fee may be partially refundable up to unused amounts of the bid fee total should a bidder successfully complete execution of a power purchase agreement.

SECTION 3. LOGISTICS

A. SCHEDULE (PROVISIONAL)

Milestone	Date
RFP Submitted to UT Public Service Commission for review	11/19/2024
RFP issued to market and Q&A period begins	5/22/2025
Q&A period ends	6/10/2025
RFP Bids Due	7/10/2025
Phase 1: Consultant Completes Bid Eligibility Screening and Begins Phase 2 Evaluation	7/25/2025
Phase 2: Agency Selects Initial Short List	8/18/2025
Phase 3: PacifiCorp Begins Modeling System Benefits	9/2/2025
Phase 3: PacifiCorp Delivers System Benefit Modeling Results to Agency	11/6/2025
Phase 3: System Benefit and Indicative Costs Discussions with Agency Begins	11/21/2025
Phase 3: System Benefit and Indicative Costs Discussions with Agency Ends	12/12/2025
Phase 3: Agency Completes Final Short List (FSL) Evaluation	12/16/2025
Execute Agreements	2/6/2026

The provisional schedule above is subject to change. Actual dates may vary from the provisional schedule for reasons that include, but are not limited to, negotiation time, availability of key personnel, due diligence, the evaluation or negotiation of any issues unique to any bid, bidder, or project, bidder's willingness to agree to forms of agreements desired by Company or the Agency, and actions required by any third parties. The Agency accepts no liability to the extent the actual schedule varies from the indicative schedule. The Agency is not obligated to develop a short list of bidders, to make a final selection, or to initiate or complete negotiations on any transaction.

Bidders should note the condensed schedule and be available for calls and meetings regarding bid submittals and be responsive to questions in a timely manner. The Agency will attempt to complete the bid review and screening as efficiently as possible but may require very short turnaround times on bid clarifications in order to meet the RFP milestones and schedule.

B. SUBMISSION OF QUESTIONS

Interested parties and bidders may submit questions related to this solicitation by the date indicated in Section 3.A., and the Agency will respond in a timely fashion. Pre-bid materials, bidder questions, and responses will be found at the following website: www.URC2024RFP.com.

C. AGENCY AUTHORITY AND RFP ROLES

The Agency was created pursuant to an interlocal cooperation agreement among the following communities, each of which passed a resolution stating a goal of achieving an amount equivalent to 100% of the annual electric energy supply for Participating Customers from renewable energy resources by 2030: Town of Alta, Town of Castle Valley, Coalville City, City of Cottonwood Heights, Emigration Canyon City, Francis City, Grand County, City of Holladay, City of Kearns, Midvale, Millcreek, City of Moab, Oakley City, Ogden City, Park City, Salt Lake City, Salt Lake County, Town of Springdale, and Summit County (Participating Communities). The Agency has authority to take action on behalf of all Participating Communities to implement the Act, including with regard to resource solicitation and resource acquisition in connection with the purposes of the Act. The Agency acts through the Community Renewable Energy Board (Board), made up of individual members of the Participating Communities and with voting and decision-making authority on behalf of the Agency.

This RFP has been developed by the Agency in conjunction with Company, as required by the Act. The Agency has engaged Energy Strategies ("Consultant") to assist with bid collection, evaluation, and scoring.

Company has no role in administering the RFP or selecting winning project bids. Company is the contracting party to any BTA or PPA that may result from this RFP and, as such, retains certain rights and authority with respect to BTA and PPA structures, and the evaluation of exceptions to the pro forma BTA and PPAs set forth in the appendices hereto. Company will also conduct analysis of bid pricing to determine the net costs and estimate emissions reductions of projects bid into the RFP. If Company submits bids into the RFP, it will maintain separation between the personnel responsible for modeling all bids and those individuals responsible for bidding resources into the RFP.

D. SUBMISSION OF BIDS

Bidders must create a user account and upload electronic documents to the following website: www.URC2024RFP.com

Bidders will receive an automatically-generated receipt email.

Bids will be accepted until 5:00 p.m. Mountain Prevailing Time (MPT) on July 10, 2025 as evidenced by the electronic timestamp recorded by the website document repository.

The Agency will not accept any late proposals.

All bid proposals shall have a bid validity date through 5:00 pm MPT, April 30, 2026.

E. BID EVALUATION FEES

Each bidder must submit a non-refundable bid fee as follows:

- for project bids of 10 MW or smaller: $5,000
- for project bids larger than 10 MW: $15,000

This bid fee will be required for each separate Base Bid.

Should a bid be selected for the Initial Short List for advancement to Phase 3 evaluation, Company will require an additional $12,500 analysis fee, payable to PacifiCorp. Any variations to the original bid will be submitted as a new bid and subject to the full $12,500 bid fee. The bid fee in support of Phase 3 is non-refundable should negotiations fail to produce an executed power purchase agreement. The bid fee may be partially refundable up to unused amounts of the bid fee total should a bidder successfully complete execution of a power purchase agreement. In addition to the Base Bid, the bidder may optionally include a Storage Add-On, a Post-PPA Sale Add-On, a Twenty-Year Bid Variant, and/or a BTA Bid Variant as described in Section 1, but these options may not be evaluated by the Agency for scoring purposes. However, these optional elements may be evaluated by the Agency and/or Company and feature in contract negotiations.

Proposals must be submitted in the legal name of the respondent who would be bound by any agreement with Company.

Payment of Bid Fees for Phases 1 and 2. Non-refundable Bid Fees shall be paid to the Agency according to the instructions in Appendix W. Bidder shall provide documentation of submitted bid fees, such as a receipt or confirmation number when bid is submitted. The Agency will not refund any bid fees associated with any bid, regardless of the success or failure of that bid, or if the RFP is cancelled.

Payment of Bid Fees for Phase 3. The Bid Fees for Phase 3 shall be paid to PacifiCorp according to the instructions for Phase 3 in Appendix W.

F. MINIMUM ELIGIBILTY REQUIREMENTS FOR BIDDERS

Bidders may be disqualified for failure to comply with the RFP if any of the requirements outlined in this RFP are not met to the satisfaction of the Agency as determined in its sole discretion. If proposals do not comply with these requirements, the Agency has the option

to deem the proposal non-conforming and eliminate it from further evaluation. Reasons for rejection of a bidder or its proposal include, but are not limited to:

1. Receipt of any proposal after the response deadline.
2. Failure to meet the requirements described in this RFP and provide all information requested in **Appendix C – Bid Summary and Pricing Input Sheet** of this RFP.
3. Failure to demonstrate a commercial operation date within the timeframe listed in Section 2.
4. Failure to permit disclosure of information contained in the proposal to the Agency's agents or contractors, to Company or regulators, or non-bidding parties to regulatory proceedings under appropriate confidentiality agreements.
5. Any attempt to influence the Agency, Company, or contractors in the evaluation of the proposals, outside the solicitation process.
6. Failure to provide a firm offer that includes a signed attestation from an officer of the bidder's company through the bid validity date outlined in Section 3.D. of this RFP.
7. Failure to disclose the real parties in interest in the submitted proposal.
8. Failure to clearly specify pricing for a 25-year term.
9. Failure to offer unit contingent (as generated) or system firm capacity and energy, directly interconnected with Company's network transmission system.
10. Failure to provide all estimated interconnection costs and transmission service costs, if applicable, in the bid proposal. Costs estimates shall be performed and provided by the project if a transmission provider study has not been completed or is not available at the time of submittal.
11. Proposal presents unacceptable level of development or technology risk including multiple resource types combined under a single bid.
12. Failure to materially comply with technical specification requirements in **Appendix A.**
13. Failure to submit development and construction milestone documentation that demonstrates a process to adequately acquire or purchase major equipment (i.e., wind turbine generators and related equipment, solar photovoltaic panels, inverters, tracking system, generator step-up transformers, batteries, etc.) and other critical long lead time equipment.
14. Failure to demonstrate, to the Agency's satisfaction, that it can meet the credit security requirements for the resource proposed.
15. Failure to submit information required by the Agency to evaluate the price and non-price factors described herein.
16. Failure to or inability to abide by the applicable safety standards.
17. Bidder submits an unacceptable contract structure, including but not limited to exceptions that significantly alter the structure of the pro forma PPA (**Appendix E-2**) as described in Section 4.B of this RFP.
18. Collusive bidding or any other anticompetitive behavior or conduct exists.
19. Bidder or proposed project being bid is involved in bankruptcy proceedings.
20. Failure of the bidder's authorized officer to sign the proposal.
21. Misrepresentation or failure to abide by Federal Trade Commission Green guidelines.
22. Any change in regulations or regulatory requirements that make the bidder's proposal non-conforming.

23. Any matter impairing the bidder, the specified resource or the generation of power or environmental attributes of the renewable resource.
24. Failure to provide a performance model output including hourly output values as identified in **Appendix A**.
25. Failure to provide **Exhibit D – Bidder's Credit Information**, and **Appendix C – Form 1 – Pricing Input Sheet.**
26. Bidder's failure to provide signed **Exhibit G-2 Non-reliance Letter**
27. Any matter impairing bidder, specified resources or the generation of power or non-power attributes therefrom.
28. Failure to provide documentation of site control for the project excluding right-of-way or easements for transmission, roads, or access to the site.
29. Bids containing energy generation types other than wind, PV solar, geothermal, and hydroelectric.
30. Failure of the project to directly interconnect with PacifiCorp's transmission system
31. Failure to demonstrate that the project has a draft or executed generator interconnection agreement or interconnection study report (cluster study or facilities study) with PacifiCorp showing that the project can reach commercial operation by December 31, 2029.
32. Failure to submit a resume of similar generation projects developed by the bidder or bidder's parent company that have reached commercial operation within the last five years with an explanation of any discrepancies between the original contractually agreed commercial online date (COD) and the achieved COD.
33. Failure to demonstrate that the bidder or bidder's parent company has delivered within the last five years a project of the same generation type as the project bid
34. For wind projects, failure to submit one or more years of avian studies.
35. Failure to attain an Interconnection and Project Readiness Score of at least 70%.

If Agency rejects any bid on the grounds that it fails to meet the minimum eligibility requirements above, Agency will notify the bidder and identify the minimum eligibility requirement the bid failed to meet.

G. AGENCY AND COMPANY RESERVATION OF RIGHTS AND DISCLAMERS

The Agency reserves the right, without limitation or qualification and in its sole discretion, to reject any or all bids, and to terminate or suspend this RFP in whole or in part at any time. Without limiting the foregoing, the Agency reserves the right to reject as non-responsive any or all bid proposals received for failure to meet any requirement of this RFP outlined herein. The Agency further reserves the right without qualification and in its sole discretion to decline to enter into any agreement with any bidder for any reason, including, but not limited to, change in regulations or regulatory requirements that impact Company, and/or any collusive bidding or other anticompetitive behavior or conduct of bidders. Bid fees are non-refundable per Section 3, part E.

Bidders who submit bid proposals do so without recourse against the Agency or Company, its consultants, its individual members, or against any director, officer, employee, agent, the Participating Customers or representative of any of them, for any modification or withdrawal of this RFP, rejection of any bid proposal, failure to enter into an agreement, or for any other reason relating to or arising out of this RFP. Bidders will be required to

execute **Appendix G - Confidentiality Agreement** after the Initial Short List is identified and **Appendix G - Non-Reliance Letter.**

H. ACCOUNTING

All proposals will be assessed by Company for appropriate accounting and tax treatment. Bidders must supply all information Company reasonably requires in order to make these assessments if a project is selected to the Initial Short List. According to Generally Accepted Accounting Principles, Company will establish and maintain accounts for the revenue, expenses, assets, liabilities and owners' equity associated with any and all renewable resources acquired through this solicitation and will ensure that all revenues and all expenses associated with the management and ownership of the resource(s) are properly recorded to these accounts. This will include expenses associated with work performed by Company personnel. Additionally, Company will account for the power costs associated with the resource(s) in a separate account(s).

I. CONFIDENTIALITY

The Agency and its consultant(s) will attempt to maintain the confidentiality of all bids submitted, to the extent consistent with law or regulatory order, as long as such confidentiality does not adversely impact a regulatory proceeding. It is the bidder's responsibility to clearly indicate in its proposal what information it deems to be confidential. Bidders may not mark an entire proposal as confidential, but must mark specific information on individual pages to be confidential in order to receive confidential treatment for that information.

In an effort to maintain the confidentiality of project bid pricing, all bids will be submitted to Consultant via the RFP website for initial scoring and evaluation on behalf of the Agency. Underlying project bid data is not expected to be possessed by any member communities of the Agency. However, because the underlying bids may ultimately be deemed subject to Utah's Government Records Access Management Act (GRAMA), the Agency recommends that every project bid be submitted with a letter asserting a claim of business confidentiality pursuant to Utah Code Section 63G-2-305(2) and in accordance with Utah Code Section 63G-2-309. This letter must contain a description of all information in the bid that the bidder asserts is confidential and a concise statement of reasons supporting the bidder's claim of business confidentiality. The bidder expressly acknowledges that the Agency's consultant may retain information submitted by the bidder in connection with this RFP until June 30, 2026. To the extent bidder receives information from the Agency or its consultants, bidder shall maintain the confidentiality of such information and such information shall not be available to any entity before, during, or after this RFP process unless required by law or regulatory order.

Only those Agency agents or employees who are directly involved in the RFP process or with the need to know for business reasons will be afforded the opportunity to view submitted bids or bidder information.

Bidders should be aware that information supplied by bidders may be requested and supplied during regulatory proceedings, subject to appropriate confidentiality provisions applicable to that particular proceeding. This means that parties to regulatory proceedings

may request and view confidential information. If such a request occurs, the Agency will attempt to prevent such confidential bidder information from being supplied to intervening parties who are also bidders, or who may be providing services to a bidder, but the Agency cannot promise success in that endeavor and accordingly cannot be held liable for any information that it is ordered to be released or that is inadvertently released.

Calculations of net costs provided by Company to Agency are considered confidential by Company and results will not be shared with bidders.

SECTION 4. RFP CONTENT

A. ALL PROPOSALS

Bidders must create a user account and upload electronic documents to the following website: www.URC2024RFP.com

Bids must include all information as described in this solicitation narrative and further detailed in **Appendix B-2: Bid Proposal Instructions and Required Information**, which contains a list of appendices to be completed for the Base Bid, optional add-ons, and optional variants, and describes what information must be included in the written proposal.

B. POWER PURCHASE AGREEMENT

Bids must contain all of the information requested in **Appendix E-1 – PPA Instructions to Bidders.** For the required Base Bid, the term of the PPA shall be twenty-five (25) years with a fixed price in dollars per Megawatt-hour ($ per MWh).

Appendix C – **Bid Summary and Pricing Input Sheet** shows the form of pricing information required for the Base Bid PPA structure as well as questions and forms related to the optional bid add-ons and variants. This is an Excel-based worksheet that covers bid summary information, electrical interconnection information, 8760 energy production profile, PV degradation information, and pricing for the PPA.

In the event Company is required to consolidate the entity under variable interest entity (VIE) accounting requirements, the entity will be required to provide the financial statement information to Company throughout the term of the agreement that is necessary to consolidate the entity.

The determination of consolidation under variable interest entity accounting requirements requires a comprehensive evaluation, including an assessment as to who has the ability to direct key economic decisions of the entity and who is required to absorb the gains and losses of the entity. The entity that meets these two requirements is generally considered the primary beneficiary and is required to consolidate the entity if it is considered a variable interest entity and if the contract is a variable interest. Typically, a fixed price per unit contract would indicate that Company does not have a variable interest and does not absorb the gains and losses of the entity. In this case, it is unlikely that the entity would be

consolidated. The Agency reserves the right to request additional information in order to complete its evaluation of tax ownership for VIE accounting requirements if necessary.

Please also refer to Section 5.F of this RFP.

For the purposes of evaluating tax ownership, bidders of longer-term contract offers must be prepared to submit, at Company's request, documentation from an independent engineer that supports the economic useful life of the underlying asset that will be used by the bidder.

The bidder's proposal must contain the information requested in **Appendix E-1 PPA Instructions to bidders**. The bidder must provide documentation and information, representations, and warranties sufficient to assure the Agency and Company that any proposed project will successfully complete construction and achieve full operation within the timeframe listed in Section 2, and that any new resource will be eligible to claim, as applicable, the full or partial federal PTC/ITC as interpreted by applicable guidelines and rules of the Internal Revenue Service.

Bidders are required to include a redlined or marked up version of **Appendix E-2 Power Purchase Agreement** showing exceptions to the terms of the pro forma PPA document, unless they indicate that they will accept the PPA "as-is". Bidders objecting to terms should provide alternate language and context to the objections for the Agency and Company to evaluate the alternate language. Bidders should also submit comments to the pro forma agreement on issues that they have concerns with and identify alternatives to address the issues. Providing a redline is a requirement for eligibility; however substantive comments should also be provided to provide context to the redlined document.

BIDDERS SHOULD BE AWARE THAT, IF THEIR BID IS SELECTED, THE BIDDER WILL BE REQUIRED TO COMPLETE A QUALIFYING REPORTING ENTITY (QRE) SERVICES AGREEMENT AS PART OF THE PPA WHICH ESTABLISHES WREGIS REGISTRATION AND REPORTING OBLIGATIONS FOR PARTIES ONCE THE RESOURCE IS IN COMMERCIAL OPERATION.

C. BUILD TRANSFER AGREEMENT

Each bid may opt to include a BTA Bid Variant that includes a "Build-Transfer" transaction whereby the bidder develops the project, assumes full responsibility for construction and commissioning of the project, transfers title to the project, potentially in stages, to Company prior to mechanical completion and thereafter completes construction and commissioning of the project, all pursuant to the terms of the build transfer agreement ("BTA"). Bids including such BTA Bid Variant proposals shall provide the following information.

Appendix C – Bid Summary and Pricing Input Sheet shows the form of project information required for a "Build-Transfer" transaction. This is an Excel-based worksheet that covers bid summary information, electrical interconnection information, 8760 energy production profile, PV degradation information, and pricing and other cost assumption inputs for the BTA. The bidder's proposal must contain the information requested in **Appendix F-1 – BTA Instructions to Bidders**. The bidder must provide information, representations, and warranties sufficient to assure the Agency and Company that any

proposed project will successfully complete construction and achieve full commercial operation within the timeframe listed in Section 2. The bidder must also provide evidence that any new resource will be eligible to claim, as applicable, the full or partial federal PTC/ITC as interpreted by applicable guidelines and rules of the Internal Revenue Service. Under the BTA, the bidder will assume full responsibility for the loss of any PTC/ITC, including due to failure to achieve full commercial operation within the timeframe listed in Section 2 or to satisfy applicable guidelines and rules of the Internal Revenue Service.

The BTA pro forma documents are attached as **Appendix F-2 – Build Transfer Agreement (BTA)**. Bidders should include a redlined or marked up version of **Appendix F-2 Build Transfer Agreement** showing exceptions to the terms of the pro forma BTA document. Bidders objecting to terms should provide alternate language and context to the objections for the Agency and Company to evaluate the alternate language. **Any exceptions that represent significant modifications to the pro forma BTA may result in rejection of the bid as non-compliant. The Agency will reject as non-compliant any bid which proposes to transfer to Company the stock or membership interest (as opposed to assets) of one or more companies which own the project.**

The BTA is structured such that Company makes progress payments on an agreed-upon schedule in exchange for the developer meeting certain milestones and deliverables. All bidders in this category must complete the information requested in **Appendix C – Bid Summary and Pricing Input Sheet** (BTA tabs). The Agency will only accept BTA proposals in which Company purchases the project prior to "mechanical completion" (as further specified in the BTA) and the bidder retains full responsibility to complete construction and commissioning of the project thereafter through commercial operation.

The bidder will be responsible for, in accordance with the requirements of this RFP, all aspects of the development and construction of the facility, including, but not limited to, site control, permitting, engineering, procurement, construction, interconnection and all related costs up to achieving commercial operation. Without limiting the foregoing, the bidder will be responsible for obtaining all necessary real property interests, permits, rights and resources required to construct and provide an operational generation resource consistent with the bidder's proposal. BTA bids must identify and provide all taxes including but not limited to property, sales and use incurred during construction and are the responsibility of the developer.

Bidders will be responsible for submitting an operation and maintenance (O&M) service proposal as part of the overall BTA bid submittal consistent with **Appendix K (BTA) Operations and Maintenance Services**. **Any proposal that does not include an O&M proposal that provides pricing, scope and other key terms will be rejected as a nonconforming proposal.**

Bidders should note that any proposal submitted in this category that proposes new construction of a resource must comply with the applicable technical and construction specifications contained in **Appendix A – 2024 Utah Renewable Project Technical Specification** and must utilize the services of a single primary contractor.

To the extent the bidder uses a contractor or a separate legal entity other than the bidder itself, this entity must be experienced with the type of facility being proposed and meet credit criteria, all as deemed acceptable to the Agency and Company.

Bidders should indicate in their bid documents whether a purchase option for a BTA has already been negotiated or is in the process of being negotiated with Company.

SECTION 5. RESOURCE INFORMATION

A. BID SUMMARY INFORMATION

Bidders must supply bid summary and pricing information using the instructions in Appendix C-1 and filling out the spreadsheet in Appendix C-2.

B. DIRECT INTERCONNECTION WITH THE PACIFICORP TRANSMISSION SYSTEM

The Agency is seeking renewable resources capable of directly interconnecting with PacifiCorp's transmission system in its PACE balancing area.[5] The Agency prefers bids that will not face significant transmission costs or constraints between: (1) the resource's point of interconnection or the resource's delivery point on PacifiCorp's transmission system; and (2) PacifiCorp network load. Bidders are thus required to provide as much granularity and documentation as possible regarding their proposed point of interconnection. Bidders should also indicate with their bids whether their project will include any jointly owned generation tie lines or other shared facilities arrangements.

As noted above, bidders should provide evidence that the proposed project has requested a direct interconnection with PacifiCorp's transmission system and has received, at a minimum, a cluster study report with PacifiCorp's transmission function supporting commercial operation no later than December 31, 2029.

All bid proposals that will require a new electrical interconnection or an upgrade to an existing electrical interconnection must include a firm statement of the cost of interconnection (broken out between network upgrade costs and facility-specific or direct assigned interconnection costs), together with a diagram of the interconnection facilities. The interconnection costs included in the bids from all bidders will be considered by the bid evaluation team as firm costs and included in the bid evaluation. Interconnection costs should be clearly identified in the resource cost proposal and differentiate the portion of costs associated with network upgrades and that portion that are facility-specific.

Before any final transaction agreements with winning bidders are executed, the Agency will require an interconnection Facilities Study report to determine the final network upgrades and direct assigned cost for interconnection service. Bids will be evaluated based on the direct assigned interconnection costs submitted in the bids, which will be considered firm costs for the Initial Short List evaluation. Bids that are selected to the Initial Short

[5] To further clarify, projects should interconnect directly to the PacifiCorp transmission system and be located in Idaho, Utah, or Wyoming.

List will be held to their pricing for the Final Short List evaluation. If selected to the Final Short List, bidder's agreement with Company, and any final transaction agreement, will include a condition precedent that states the Agency will compare the actual direct assigned and network upgrade costs associated with the interconnection from the most recent completed system impact/cluster study (SIS) or Facilities Study (FS) with the bidder's firm estimate provided in their best and final price. In the event the actual direct assigned SIS cost exceeds the bidder's interconnection cost in best and final pricing, bidder will be responsible for the cost above their best and final firm price. In the event the actual SIS direct assigned cost is less than the bidder's firm interconnection cost estimate, the Agency will require an adjustment of the final PPA price to reflect the reduction in interconnection costs. The Agency will examine critical study information such as: (1) whether the studies support a commercial operation date within the timeframe listed in Section 2; and (2) interconnection direct assigned and network upgrade costs.

All proposals will require firm transmission service on PacifiCorp's network transmission system and proposed resources must be able to be designated by PacifiCorp's Energy Supply Management (ESM) function as a Network Resource under the network service contract between PacifiCorp Transmission (www.oasis.pacificorp.com) and PacifiCorp ESM. The final transaction agreement includes a condition precedent that should designation as a Network Resource (DNR) require additional upgrades beyond those identified in the interconnection study, the bidder may be required to bear the additional cost.

C. FERC'S STANDARDS OF CONDUCT

Each bidder responding to this RFP must conduct its communications, implementation and operations in compliance with FERC's Standards of Conduct for Transmission Providers (see **Appendix I**), requiring the separation of transmission and merchant functions. Any interconnection or transmission service agreement is NOT a transmission service agreement with PacifiCorp's ESM merchant function; rather, it is with PacifiCorp's transmission function or other third-party transmission provider. As such, the bidder must follow the transmission provider's OASIS process. If requested, bidders shall execute a customer consent form (see Appendix J PacifiCorp Transmission Waiver) consistent with FERC requirements that enables PacifiCorp's ESM merchant function to discuss the bidder's interconnection and/or transmission service application(s) with the transmission interconnection or transmission service provider.

D. RESOURCE TYPES ELIGIBLE TO BID

The Agency is seeking new renewable energy resources capable of directly interconnecting to PacifiCorp's network transmission system between January 1, 2026 and December 31, 2029. The Agency is limiting the resource types to wind, PV solar, geothermal, and hydroelectric only and will not accept bids that combine these technologies with other technologies except for co-located storage resources. These resources must be capable of being interconnected with PacifiCorp's transmission system.

E. TAX CREDITS AND/OR PROJECT INCENTIVES

Bidders must bear all risks, financial and otherwise, associated with bidder's or the facility's eligibility to receive any state or federal energy tax credits, sales tax waivers or exemptions or any other identified tax credit or incentive, or qualify for accelerated depreciation for bidder's accounting, reporting or tax purposes, as applicable. The obligations of the bidder to perform under any executed agreement as a result of this solicitation shall be effective and binding regardless of whether the sale of or output from the bidder's facility under such agreement is eligible for, or receives investment tax credits, or other identified tax credits/incentives.

The Agency will require written documentation of the amount, timing and control of any and all available tax credits/incentives that the bidder's facility is eligible for, applied for, and/or received. Such documentation shall include but not be limited to ownership rights to the credit, grant or incentive, timing including expiration dates and milestones to achieve the credit, grant, or incentive.

F. ACCOUNTING AND TAX CONSIDERATIONS

All contracts proposed to be entered into as a result of this RFP will be assessed by Company for appropriate accounting and tax treatment. Bidders shall be required to supply Company with any and all information that Company reasonably requires in order to make preliminary assessments if the bid is selected to the Initial Short List. Specifically, given the term length of the PPA or BTA arrangement, accounting and tax rules may require either: (i) a contract be accounted for by Company as a finance lease or operating lease[6] for book purposes pursuant to ASC 842, (ii) a contract be accounted for by Company as a capital lease for tax purposes[7], or (iii) the seller or assets owned by the seller, as a result of an applicable contract, be consolidated as a VIE into Company's financial statements.[8]

G. COST ASSOCIATED WITH DIRECT OR INFERRED DEBT

The Agency will not take into account potential costs to Company associated with direct or inferred debt (described below) as part of its economic analysis in the short list evaluations. However, after completing the Final Short List and before the final resource selections are made, the Agency and Company may take direct or inferred debt into consideration. In so doing, Company may obtain a written advisory opinion from a rating agency to substantiate Company's analysis and final decision regarding direct or inferred debt.

Direct debt results when a contract is deemed to be a lease pursuant to ASC 842 and liability reflected on Company's balance sheet.

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[6] "Finance Lease" and "Operating Lease" - shall have the meaning as set forth in the Accounting Standards Codification (ASC) 842 as issued and amended from time to time by the Financial Accounting Standards Board.

[7] See IRS Code Section 7701(e) describing the test for finance lease for tax purposes.

[8] "Variable Interest Entity" or "VIE" - shall have the meaning as set forth in ASC 810 as issued and amended from time to time by the FASB.

Inferred debt results when credit rating agencies infer an amount of debt associated with a power supply contract and, as a result, take the added debt into account when reviewing Company's credit standing.

SECTION 6. BID EVALUATION AND SELECTION

A. OVERVIEW OF THE EVALUATION PROCESS

The Agency's bid evaluation and selection process is designed to identify the combination and amount of new renewable projects bid into the 2024 URC RFP that will cost-effectively support URC member communities' goals to achieve net-100% renewable electricity on behalf of Participating Customers by 2030. The Agency will not make any of the evaluation models available to bidders.

The bid evaluation process will occur in three phases. In the first phase, the Agency will calculate an Interconnection and Project Readiness Score (IPRS) and reject non-conforming bids. Although not a scoring element, the IPRS will be used to reject project bids scoring less than 70% and to adjust non-price scoring elements in the third phase.

In the second phase, price (expressed in $ per MWh) and non-price scoring elements will be evaluated to develop an Initial Short List of projects consisting of up to six bids across two categories: 1) wind and solar – W&S, and 2) geothermal and hydropower (G&H).

In the third phase, PacifiCorp will model two scoring inputs for each bid selected to the Initial Short List: a financial benefit (expressed in $ per MWh) and avoided climate pollution through 2030 (expressed in metric tons of CO2-equivalent). Any other factors not expressly included in the formal evaluation process but required by applicable law or Commission order, will be used by the Agency to establish the Final Short List.

Representatives from the Agency, its Consultant, or Company may contact bidders to confirm and clarify information presented in each proposal.

After the Final Short List is established, Company will initiate negotiations with projects from the Final Short List that are selected by the Agency by a vote of its Board. Selection of a bid to the Final Short List does not constitute a winning bid. Only execution of a definitive agreement between Company and the bidder, on terms acceptable to the Agency and Company, in their sole and absolute discretion, will constitute a winning bid proposal. Any definitive PPA or BTA will be in the form of the PPA or BTA contracts provided in **Appendices E-2** and **F-2,** respectively. If the bidder alters the PPA or BTA, or does not use it as the underlying agreement, bid evaluation and selection can be affected. The Agency welcomes bidders, at their own discretion, to provide written comments on the PPA or BTA provided in **Appendices E-2** and **F-2** as part of their bid. Neither the Agency nor Company has a legal obligation to enter into any agreement of any kind with any bidder.

B. PHASE 1 – INTERCONNECTION AND PROJECT READINESS

Project bids that have not already been rejected as non-conforming will be evaluated using an Interconnection and Project Readiness Score (IPRS). This evaluation consists of ten questions as follows:

Interconnection and Project Readiness Score Factors	Scoring Weight
1. Does project have site control necessary to support a generation facility? (Yes = 1, No = 0)	1
2. Does project have site control necessary to support a generation-intertie ("gen-tie") needed to interconnect the project on the transmission system? (Yes = 1, No = 0)	1
3. Does project have a signed generator interconnection agreement? (Yes = 1, No = 0)	1
4. Does this project have at least one of the following: (1) it has passed fast-tracked under section 50 of PacifiCorp's OATT, (2) it has been issued an executable interconnection agreement under PacifiCorp's OATT section 51.4.3, or (3) it has a facilities study, either final or draft? (Yes = 1, No = 0) *Please note: OATT references are to PacifiCorp's Open Access Transmission Tariff v.2.0.0 dated April 1, 2020*	1
5. Has this project been studied as a Network Resource Interconnection Service (NRIS) or does it pass as fast-tracked under section 50 of PacifiCorp's OATT? (Yes = 1, No = 0)	1
6. Wetlands are either not present or mitigation plans are in place. (True = 1, False = 0)	1
7. Endangered species are either not present on site or mitigation plans are in place (True = 1, False = 0)	1
8. Cultural resources are either not present or mitigation plans are in place (True = 1, False = 0)	1
9. Site is zoned for proposed use (True = 1, False = 0)	1
10. Permitting is complete (i.e., project is shovel-ready) (True = 1, False = 0)	1

The total points will be summed and divided by 10 total possible points to develop an IPRS expressed as a percentage. Project bids with an IPRS lower than 70% will be rejected and the IPRS will be carried forward into the second phase of project bid evaluation.

C. PHASE 2 – INITIAL SHORT LIST

1. Price Evaluation (up to 70 points)

The Agency is committed to procuring least cost/least risk renewable energy through this solicitation on behalf of the Participating Customers.[9] In phase 2, the Agency will compare the all-in cost (expressed in $ per MWh)—inclusive of network upgrade costs associated with interconnecting the resource—among all bids that have met the threshold requirements described in phase 1. The lowest cost bid will be awarded 70 points and all other bids will be awarded a pro-rated share of 70 points based on how much more expensive they are than the lowest cost bid. This price evaluation will consider the pricing

[9] As noted above, the Agency is under no obligation to procure resources bid into this RFP.

of the base 25-year project term. Please see Section 6.C.3 for a discussion of how wind and solar (W&S) bids will be ranked in a different list from geothermal and hydropower (G&H) bids for the purpose of selecting up to six (6) bids for the Initial Short List.

Bids must include documentation that demonstrates that the project(s) qualify for and will receive the full or partial value of the federal PTC or ITC as interpreted by applicable guidelines and rules of the Internal Revenue Service at commercial operation. The bids will be ranked to determine an initial shortlist, after also taking into account the Non-Price Evaluation.

2. Non-Price Evaluation (Up To 13 points)

The non-price scoring factors will be evaluated as follows:

NON-PRICE FACTOR WEIGHTING

Non-Price Factors	Non-Price Scoring Weight
1. Is the project located in Utah? (Yes = 3, No = 0)	3
2. If your project is located in Utah, will at least 50% of construction labor hours be supplied by in-state labor at the bid price? (Yes = 1, No = 0)	1
3. Will your project meet prevailing wage requirements for construction labor at the bid price? (Yes = 1, No = 0)	1
4. Will at least 2% of construction labor hours be supplied by registered apprenticeship labor at the bid price? (Yes = 1, No = 0)	1
5. Is your project located in a (1) 2024 Coal Closure Energy Community * or (2) disadvantaged area** as indicated on Federal maps? (Yes = 2, No = 0)	2
6. Inclusive of construction activities, how much water will your project consume in gallons per MW-hr over its operational life? (None = 2, between 0 and 20 = 1, more than 20 = 0)	2
7. By what date can your project reach commercial operation and deliver energy to the PacifiCorp transmission system, as evidenced by the most recent cluster or facilities interconnection study report or generator interconnection agreement? (by Dec 2026 = 3, between Jan and Dec 2027 = 2, between Jan and Dec 2028 = 1, between Jan and Dec 2029 = 0)	3

***2024 Coal Closure Energy Communities are light- or dark-green shaded areas in the United States Department of Energy Community Tax Credit Bonus Map**

****Disadvantaged areas are green-shaded areas in the archived EJScreen tool.** *Please note: to turn on the Designated Disadvantaged Communities layer, click Places > Designated Disadvantaged Communities > EPA IRA Disadvantaged Communities and in the Map Contents box, ensure that EPA IRA Data 2.0 is checked.*

3. Initial Short List Selection

The Agency will use the combined price and non-price results for valid bids to rank them in two separate lists: one list of all wind and solar bids (W&S) and a second list of all geothermal and hydropower bids (G&H). So long as there are G&H bids that meet all

screening criteria and survive Phase 1 scoring, up to three (3) top scoring bids will be selected from the G&H category; then, three (3) or more top scoring bids will be selected from the W&S category to bring the total bids selected for the Initial Short List and advancing to Phase 3 to no more than six (6) bids. Should any project bids of 10 MW or smaller size advance to Phase 2, the Agency reserves the right to select up to one (1) such bid to the Initial Short List.

In making Initial Short List selections, the Agency will consider the anticipated impact on the program rate that will be paid by Participating Customers. The total contract cost, commercial online date, and need to establish a dedicated reserve fund are all factors that may influence the program rate.

The Agency anticipates that the Initial Short List will represent approximately 500 MW of aggregate capacity. However, the Agency may establish an Initial Short List containing less or more aggregate capacity depending upon the relative total bid score among the bids and the total capacity bid into each category.

Network customers of PacifiCorp transmission, including Company, can request non-binding studies to provide an estimate of potential, high-level costs related to adding a potential designated network resource at a particular location on the system. While intervening transmission service requests or other changes on the system could impact the accuracy of the non-binding study estimates, these nevertheless provide a reasonable tool to evaluate potential transmission service costs before a final agreement is reached with a bidder. Accordingly, for all bids included in the Initial Short List, the Agency also reserves the right to request an informal study from PacifiCorp transmission to identify potential network upgrade costs that might be necessary for the bidder's facility to be designated as a network resource on PacifiCorp's transmission system. The cost of this non-binding study is to be paid by the bidder.

D. PHASE 3 – FINAL SHORT LIST

1. Price Evaluation (up to 70 points)

To be evaluated for Phase 3, Company will require an additional $12,500 bid analysis fee for each Base Bid, variant, and/or add-on selected by the Agency to the Initial Short List and a signed Appendix G-2: Non-Reliance Letter prior to calculating a financial benefit (expressed in $ per MWh). For clarity, Phase 3 evaluation of a bidder's Base Bid and an optional Storage Add-On will be subject to a $25,000 bid analysis fee. If a bidder does not (a) execute this agreement with Company and (b) deliver this payment to Company by August 22, 2025, the Agency may remove that bid from the Initial Short List and replace it with a different bid.

Company will assess Initial Short List bids for the appropriate accounting and tax treatment. PPA bids will be evaluated to determine: (i) whether a contract must be accounted for by Company as a finance lease or operating lease in accordance with ASC 842 for book purposes, (ii) whether a contract must be accounted for by Company as a capital lease for tax purposes, or (iii) whether the seller or assets owned by the seller, as a result of an applicable contract, shall be consolidated as a VIE into PacifiCorp's financial

statements. Potential accounting treatment impacts will be incorporated into the bid evaluation and selection process. Please also refer to Section 5.F of this RFP.

For project bids that involve generation types other than solar, wind, and hydro, or storage types other than batteries, the bidder may be required to cover the cost for Company to hire a third party to support calculation of the financial benefits.

Net-Cost of Energy (35 points)

For each Initial Short List bid, the net-cost of energy will be calculated as the difference between the PPA fixed price (expressed in $ per MWh) and the financial benefit (expressed in $ per MWh).

The Agency will compare the net-cost of energy (expressed in $ per MWh) among all Initial Short List bids. The bid with the lowest net-cost of energy (which may be negative) will be awarded 35 points. For all other project bids, the net-cost of energy will be compared to the lowest net-cost of energy. For every $1 per MWh of net-cost of energy that a project bid exceeds the lowest net-cost of energy bid, 2 points will be deducted from the 35 possible points. For example, if the lowest net-cost of energy bid is -$5 per MWh and another project bid's net-cost of energy is $0 per MWh, the first project bid would receive 35 points and the second project bid would receive (35 – 10 =) 25 points.

Net-Cost of Contract (35 points)

For each Initial Short List bid, the net-cost of contract will be calculated as the net present value of the net-cost of energy over the 25-year term of the PPA (expressed in $).

The Agency will compare the net-cost of contract (expressed in $) among all Initial Short List bids. The project bid with the lowest net-cost of contract (which may be negative) will be awarded 35 points while project bids with a net-cost of contract of $45 million or more will be awarded 0 points. All other project bids will be awarded a prorated share of 35 points based on how much more expensive they are compared to the lowest net-cost of contract.

2. Non-Price Evaluation (up to 30 points)

Commercial Online Date Confidence Score (up to 4 points)

Consultant will review interconnection studies and related documentation for every Initial Short List bid and assign a Commercial Online Date Confidence Score as shown:

- No, the document review does not support the indicated online date: 0
- No, the document review suggests the indicated online date is unlikely: 1
- Maybe, the document review suggests the indicated online date is possible: 2
- Yes, the document review suggests the indicated online date is likely: 3
- Yes, the document review suggests the indicated online date is substantially supported: 4

Adjusted CO_2 Reduction Score (up to 13 points)

PacifiCorp will model projected carbon dioxide reductions for each Initial Short List bid from the indicated commercial online date through 2030 (expressed in metric tons of CO2). These carbon dioxide reductions result from changes in how PacifiCorp's thermal power plants are dispatched in response to new sources of generation.

The modeled CO_2 reductions through 2030 will be adjusted by the Commercial Online Date Score converted to a percentage. For example, if an Initial Short List bid receives a Commercial Online Date Score of 2 out of 4 (50%), then the bid's modeled CO_2 reduction (in metric tons) will be adjusted to 50% of its original value.

The adjusted CO_2 reduction (in metric tons) will be compared among all Initial Short List bids. The bid with the largest adjusted CO_2 reduction through 2030 will receive 13 points and all other bids will be awarded a prorated share of 13 points based on how many fewer tons of adjusted carbon dioxide pollution they will reduce compared to the project bid with the largest reduction.

Non-Price Factors Previously Scored in Phase 2 (up to 13 points)

The non-price scoring factors from phase 2 will also be included in the non-price evaluation for phase 3.

3. Other Factors: Applicable Law and Statutory Requirements

The bid methodology has been designed to capture applicable law and statutory requirements. Before establishing a final shortlist, the Agency may take into consideration other factors that are not expressly or adequately factored into the evaluation process outlined above, particularly any factor required by applicable law or Commission order to be considered.

4. Final Short List Selection

The Agency will summarize and evaluate the results of its price and non-price scores among all surviving project bids. Based on these data and certain other factors as described above the Agency may establish a Final Short List. Once the Final Short List is established and bidders notified, the Agency may select by a vote of its Board one or more project bids for contract negotiation. Should any project bids of 10 MW or smaller advance to Phase 3, the Agency reserves the right to select up to one (1) such bid for contract negotiation.

In selecting one or more project bids from the Final Short List for contract negotiation, the Agency will consider the anticipated impact on the program rate that will be paid by Participating Customers. The net-cost of energy, net-cost of contract, total contract cost, commercial online date, and need to establish a dedicated reserve fund are all factors that may influence the program rate.

Company will not enter into any agreement without Agency approval.

5. BTA Bid Evaluation

If a Base Bid that contains a BTA Bid Variant is selected to the Final Short List and is approved by the Agency's Board for contract negotiation, Company may elect to pursue a BTA with the bidder when the project proceeds to the contract negotiation phase.

SECTION 7. INVITATION TO BID

A. INVITATION

This RFP contains only an invitation to make proposals to the Agency. No proposal is itself a binding contract unless the parties execute definitive and complete documentation providing otherwise.

The Agency may in its sole discretion do any one or more of the following:

1. Determine which proposals are eligible for consideration in response to this RFP.
2. Issue additional subsequent solicitations for information and conduct investigations with respect to the qualifications of each bidder.
3. Supplement, amend, or otherwise modify this RFP, or cancel this RFP with or without the substitution of another RFP.
4. Negotiate with bidders to amend any proposal.
5. Require winning bidder(s) to provide an additional administrative fee.
6. Select and enter into agreements with the bidders who, in the Agency's sole judgment, are most responsive to the RFP and whose proposals best satisfy the interests of the Agency and the Participating Customers, and not necessarily on the basis of price alone or any other single factor.
7. Issue additional subsequent solicitations for proposals.
8. Waive any irregularity or informality on any proposal to the extent not prohibited by law.
9. Reject any or all proposals in whole or in part.
10. Vary any timetable.
11. Conduct any briefing session or further RFP process on any terms and conditions.
12. Withdraw any invitation to submit a response.

B. CONFIDENTIALITY AGREEMENT

In addition to the confidentiality provisions set forth herein, bidders should note that all parties will be required to sign **Appendix G-1 – Confidentiality Agreement** with the Agency upon bid submission, as well as a transmission voluntary consent notice to authorize the release of data to PacifiCorp's ESM Market Function from PacifiCorp Transmission.

C. NON-RELIANCE LETTER

All parties will be required to sign **Appendix G-2 - Non-Reliance Letter** if they qualify for the Initial Short List prior to the Company modeling the financial impact of the project bid.

D. POST-BID NEGOTIATION

Company will further negotiate both price and non-price factors during post-bid negotiations. The Agency will also include in its evaluation any factor that may impact the total cost of a resource, including but not limited to all of the factors used in the Final Short List cost analysis plus consideration of accounting treatment and potential effects due to rating agency treatment, if applicable. Post-bid negotiation will be based on the Agency's cost assessment. The Agency will continually update its economic and risk evaluations until Company and the bidder execute a definitive agreement acceptable to Company. The Agency must approve any contract negotiated between Company and the bidder.

Neither the Agency nor Company shall have any obligation to enter into any agreement with any bidder to this RFP and the Agency may terminate or modify this RFP at any time without liability or obligation to any bidder. In addition, this RFP shall not be construed as preventing the Agency or Company from entering into any agreement that the Agency or Company deems prudent, in each of the Agency's and Company's independent sole discretion, at any time before, during, or after this RFP process is complete. Finally, the Agency reserves the right to negotiate only with those entities that propose transactions that the Agency believes in its sole discretion to have a reasonable likelihood of being executed.

E. SUBSEQUENT REGULATORY ACTION

Unless mutually agreed between the parties or unless required by actual (or proposed) law or regulatory order, at the time of contract execution, the Agency does not intend to include a contractual clause whereby the Agency is allowed to adjust contract prices in the event that an entity that has regulatory jurisdiction over Rocky Mountain Power does not fully recognize the contract prices. As of the issuance date for this solicitation, the Agency is unaware of any such actual law or regulatory order.

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Exhibit 2-111:
Western Energy Imbalance Market Webpage

WESTERN ENERGY MARKETS



The ISO's Western Energy Imbalance Market enhances grid reliability while meeting the needs of an evolving industry through collaborative efforts across the West

Western Energy Imbalance Market (WEIM)

The ISO's Western Energy Imbalance Market is a real-time energy market, the first of its kind in the western United States.

The WEIM's advanced market system automatically finds low-cost energy to serve real-time consumer demand across the west. Since its launch in 2014, the WEIM has enhanced grid reliability and generated cost savings for its participants. Besides its economic advantages, the WEIM improves the integration of renewable energy, which leads to a cleaner, greener grid.

Participants

- Imperial Irrigation District – *planned entry 2028*
- Black Hills – *planned entry 2026*
- PowerWatch (formerly BHE Montana) – *planned entry 2026*
- Avangrid – entered 2023
- El Paso Electric – entered 2023
- WAPA Desert Southwest Region – entered 2023

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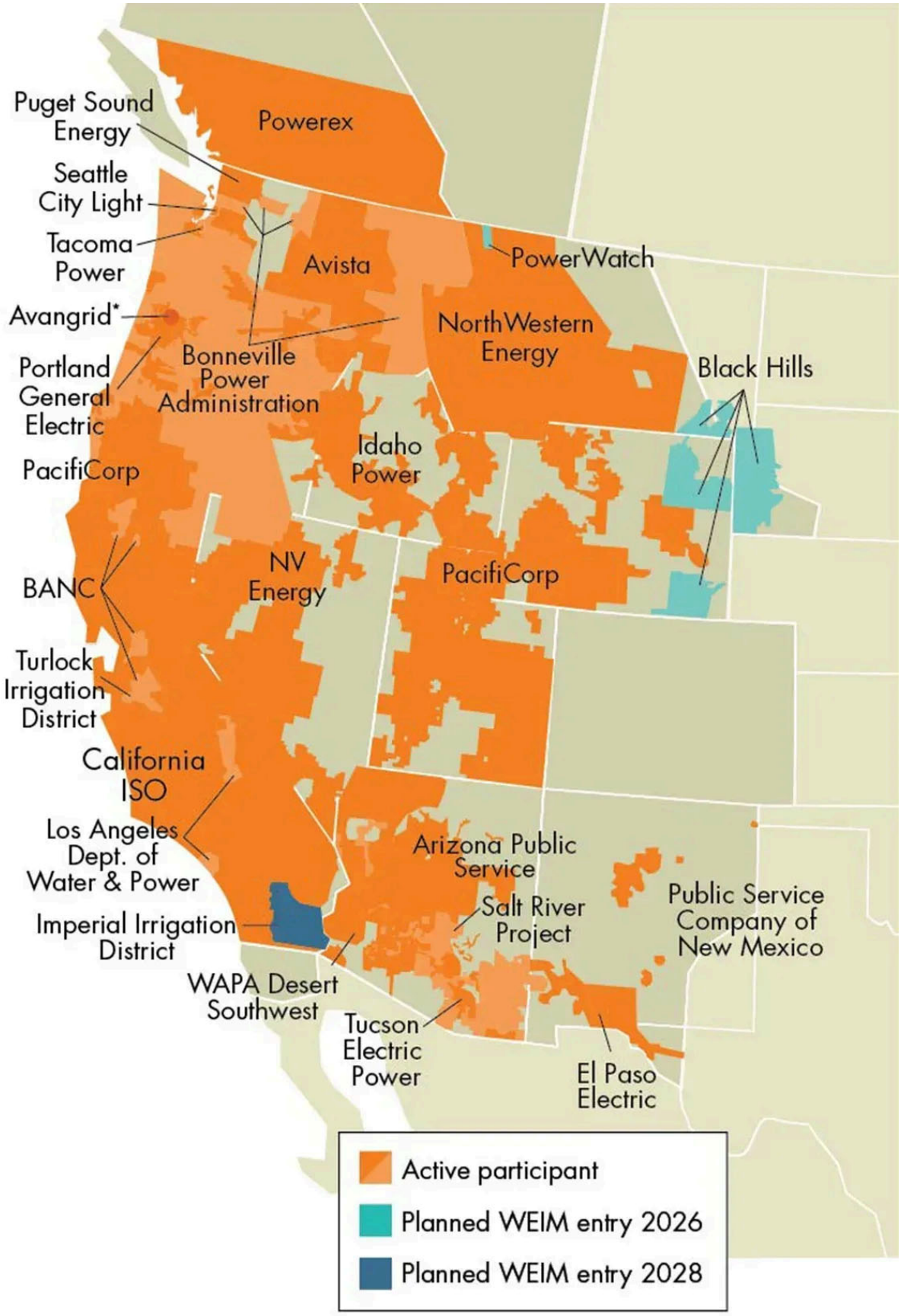
- Bonneville Power Administration – entered 2022
- Tucson Electric Power – entered 2022
- Avista – entered 2022
- Tacoma Power – entered 2022
- NorthWestern Energy – entered 2021
- Los Angeles Department of Water & Power – entered 2021
- Public Service Company of New Mexico – entered 2021
- Turlock Irrigation District – entered 2021
- Salt River Project – entered 2020
- Seattle City Light – entered 2020
- Balancing Authority of Northern California – entered 2019
- Idaho Power Company – entered 2018
- Powerex – entered 2018
- Portland General Electric – entered 2017
- Puget Sound – entered 2016
- Arizona Public Service – entered 2016
- NV Energy – entered 2015
- PacifiCorp – entered 2014
- California ISO – entered 2014

View implementation documents for participants

Participant map



**Avangrid office; generation only BAA with distribution across multiple states. Map boundaries are approximate and for illustrative purposes only. Copyright © 2025 California ISO*

Download map

See the latest quarterly benefits report.

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Exhibit 2-112:
WEIS — Southwest Power Pool

CREATE ACCOUNT LOGIN

WESTERN ENERGY IMBALANCE SERVICE MARKET

Quick Links

- SPP WEIS Marketplace Protocols

News Release Quick Links

- May 12, 2021, release announcing Colorado Springs Utilities joining SPP's western market
- Dec. 23, 2020, release announcing FERC's approval of the WEIS tariff
- Nov. 12, 2020, release announcing SPP and stakeholders will consider RTO expansion to the west; study anticipates $49M in annual savings for current and new members
- Feb. 21, 2020, release announcing WEIS tariff filing
- Dec. 12, 2019, release announcing new participants of the WEIS
- Sept. 9, 2019, release announcing the first agreements with participants of the WEIS
- June 17, 2019, release announcing WEIS proposal and design

SPP invites utilities to help build an electricity market to serve the west

SPP's Western Energy Imbalance Service market (WEIS) will balance generation and load regionally and in real time for participants in the Western Interconnection.

SPP began administering WEIS on a contract basis February 2021. Utilities do not have to be a member of the SPP regional transmission organization (RTO) to participate. The market will centrally dispatch energy from participating resources throughout the region every five minutes, enhancing both the reliability and affordability of electricity delivery from utilities to their customers.

The following are participants of the WEIS Market:

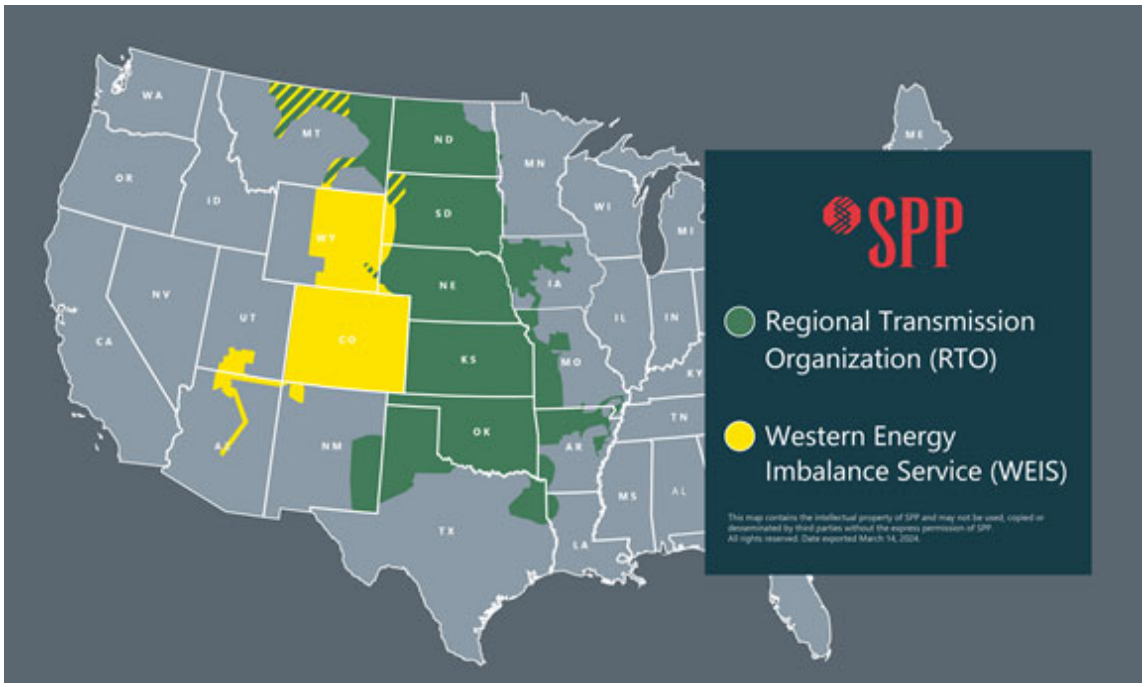
- Basin Electric Power Cooperative
- Black Hills Energy (effective April 2023)
- City of Farmington NM Electric Utility
- Colorado Springs Utilities (effective August 2022)
- Deseret Power Electric Cooperative
- Guzman Energy
- Municipal Energy Agency of Nebraska
- Platte River Power Authority (effective April 2023)
- Tri-State Generation and Transmission Association
- United Power, Inc.
- Western Area Power Administration
    - Upper Great Plains West
    - Rocky Mountain Region
    - Colorado River Storage Projects
- Xcel Energy (effective April 2023)

SPP's previous energy imbalance market went live in 2007 and provided participants with $103 million in benefits in its first year of operation.

As the market's administrator, SPP maintains reliability of the region's transmission system and meets demand with the most cost-effective generation available, reducing wholesale electricity costs for participants. Like SPP's previous markets, the WEIS provides price transparency of wholesale energy, allows parties to trade bilaterally and hedges against costly transmission congestion.

In designing the WEIS, SPP leveraged existing constructs in the west and its experience successfully building and operating its own energy imbalance market from 2007-2014, after which the RTO introduced day-ahead unit commitment and other services in the transition to its current Integrated Marketplace.

An overview of the WEIS' proposed scope and design is available in the Related Documents menu to the right.



Governance and Stakeholder Involvement

For more than 75 years, SPP has distinguished itself as a stakeholder-driven organization that achieves its business objectives through consensus-building. While SPP's independent board of directors provides ultimate oversight of the administration of the WEIS market, an open, transparent, and inclusive stakeholder process is a hallmark of our culture and business model. This same approach has been brought to the governance of the WEIS market to provide ample opportunities for stakeholder engagement and to ensure the market remains effective, efficient and competitive.

Stakeholders can stay informed of, and participate in, WEIS Market development through the Western Markets Working Group.

SPP's Western Markets Working Group (WMWG) is the forum for customers of SPP's western energy imbalance service market to engage in matters of WEIS Market related governance and strategy and with other stakeholders.

Its meetings serve as an open forum for entities looking to learn about SPP or to have a say in the development of the WEIS market in the west.

Attendees may register on SPP.org for WMWG meetings, which may be attended in-person or by phone. Those interested in learning more about SPP's provision of energy imbalance service in the west are encouraged to register and attend or to contact SPP's customer relations department.

To stay updated on the WEIS Market, subscribe to the SPP WMWG Exploder. If you do not have an account, you may create one using the Create Account button at the top right of the page.

The Change User Forum (CUF) engages market participants and monitors market and SPP readiness for the western energy imbalance service market. The CUF makes project management and process improvement recommendations to SPP staff and/or the Western Markets Executive Committee.

Want to learn more?

If you are interested in learning more about SPP's Western Energy Imbalance Service (WEIS) market, training is available. SPP provides several online self-study courses about key features of the WEIS market and participant responsibilities. If you work for an organization that is an active WEIS participant, you already have access. Register or log into the SPP Learning Center. And if you need assistance logging in or are not currently a member of SPP's WEIS market, contact SPP's Stakeholder Training Group.

WESTERN SERVICES

Western Newsroom ❯
Western Events
Markets+ ❯
RTO Expansion ❯
Western Resource Adequacy Program
Western RC Services ❯
Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP)
WEIS ❯
- WEIS Revision Requests

RELATED DOCUMENTS

Western Energy Imbalance Service Market (WEIS) Proposal

WMEC Charter

WEIS Implementation Milestones

WEIS Implementation Program Overview

2023 WEIS Course Catalog

RELATED DOCUMENT GROUPS

Western Energy Imbalance Service Market (WEIS)

Western Stakeholder Groups

Meeting materials, member info, and more.

Western Energy Service Documents

Filings, governing documents, and other resources.

Western Energy Service News

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Exhibit 2-113:
Craig Station, AMD data 2020 through 2025

State	Facility Nai	Facility ID	Unit ID	Associated Year	Operating T	Sum of the	Gross Loac	Steam Loa	SO2 Mass (	SO2 Rate (l	CO2 Mass	CO2 Rate (	NOx Mass (	NOx Rate (l	Heat Input	Primary Fu	Secondary	Unit Type	SO2 Contr	NOx Contr	PM Control	Hg Control	Program Code
CO	Craig	6021	C1	2020	8511	8490.94	2517304		560.023	0.0431	2726442	0.105	3097.992	0.2329	25995872	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C1	2021	8123	8119.01	2563445		573.766	0.0439	2751844	0.105	3095.465	0.2316	26238031	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C1	2022	8413	8393.53	2797335		742.279	0.0518	2917219	0.1049	3492.321	0.2465	27814864	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C1	2023	8083	8072.47	2015029		526.926	0.0474	2210610	0.105	2518.031	0.2337	21077513	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C1	2024	8541	8536.69	1824100		335.429	0.0325	2058659	0.105	2211.571	0.2218	19628748	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C1	2025	8097	8082.35	1724209		368.808	0.0376	1971712	0.105	2085.183	0.2159	18799715	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C2	2020	7993	7961.83	2300379		517.033	0.0404	2562694	0.105	763.524	0.0618	24434513	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C2	2021	8635	8628.91	2822038		476.124	0.0301	3177713	0.105	1014.748	0.0667	30298549	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C2	2022	8427	8420.82	2629692		645.904	0.0451	2948921	0.105	987.563	0.0698	28117158	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C2	2023	5582	5573.88	1245370		282.48	0.0381	1457229	0.105	401.375	0.0562	13894277	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C2	2024	8405	8400.47	1801957		302.703	0.0271	2209975	0.105	625.283	0.0587	21071487	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C2	2025	8480	8477.53	1873143		351.27	0.0307	2288772	0.105	648.473	0.0591	21822755	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C3	2020	7811	7789.23	2821877		1644.329	0.1077	3145100	0.105	3152.793	0.2047	29987627	Coal	Pipeline Na	Dry bottom	Dry Lime F	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C3	2021	7426	7415.67	2579840		1307.602	0.1058	2635046	0.1049	2731.044	0.2108	25124446	Coal	Pipeline Na	Dry bottom	Dry Lime F	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C3	2022	7708	7697.91	2783361		1714.714	0.1259	2837603	0.105	2973.326	0.2122	27055733	Coal	Pipeline Na	Dry bottom	Dry Lime F	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C3	2023	7624	7611.42	1981366		1195.702	0.117	2135790	0.105	2131.88	0.2023	20364134	Coal	Pipeline Na	Dry bottom	Dry Lime F	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C3	2024	6146	6137.68	1441766		666.086	0.0852	1610839	0.105	1495.032	0.1898	15358887	Coal	Pipeline Na	Dry bottom	Dry Lime F	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C3	2025	3586	3574.77	653641.1		303.611	0.0823	764357.6	0.105	709.173	0.1884	7287928	Coal	Pipeline Na	Dry bottom	Dry Lime F	Low NOx B	Baghouse		ARP, MATS

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Exhibit 2-114:
Tri-State Members

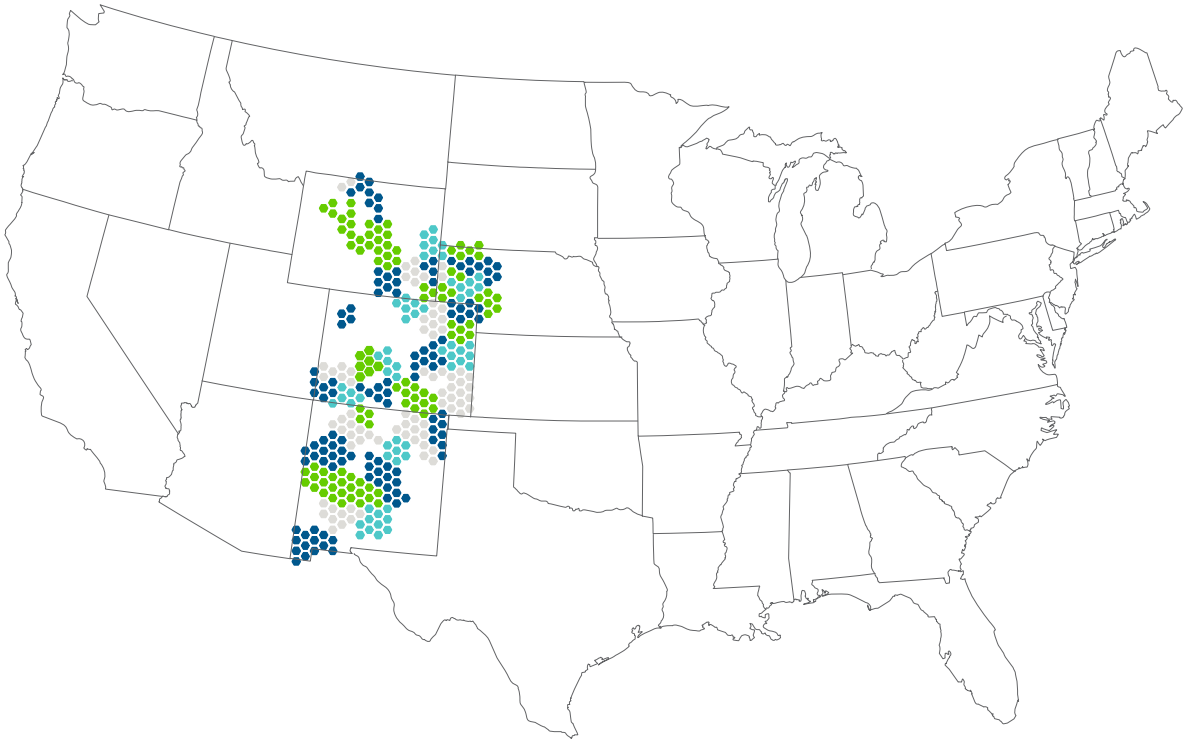
TRI-STATE </>

MENU

What it means to be a member

Tri-State is more than just an energy provider—we're a community of member-owned utilities and businesses working together across Colorado, Nebraska, New Mexico, and Wyoming. As a cooperative, our strength comes from our members, and our board of directors reflects that diversity. These board members aren't just representatives—they're ranchers, farmers, and local business owners who live and work in the same communities served by our utilities. Their firsthand experience and deep local ties help guide the decisions that shape Tri-State's future, ensuring we stay true to our mission and values.

With our members, we supply power and services that support the rural communities they serve. That is the cooperative difference—we answer to our neighbors, not shareholders.



Member List </member-list>

70+

Tri-State was founded in 1952, which means we've been supplying electricity to the rural West for over 70 years.

1M

Together with our members, we serve nearly one million people and businesses across nearly 200,000 square miles.

5.32

We average 5.32 consumers per mile, vs. the national average of 32.4. We serve electricity to some of the most rural parts of the U.S.

Meet the board chairman at the end of the line

The son of a World War II veteran and life-long New Mexico rancher, Tri-State Board Chairman Tim Rabon has seen the powerful effect of people coming together and discusses how that is the foundation of the co-op model.

Listen to the podcast </podcast-western-watts-cooperative-roots-tim-rabon-tri-state>



Power in numbers

Our association was formed to bring electricity to our members in the rural West when other power providers would not. Together we can capture economies of scale while sharing the costs and risks of supplying power to areas with few consumers, difficult terrain and a lot of ground to cover. Even today, some of our members serve as few as one connection per mile of distribution line.

But whether they're in the desert, mountains, rural towns or plains—all our members still need reliable, affordable, responsible power. By pooling resources, collectively buying and selling power and managing the backbone of infrastructure that transports that power, we can negotiate better prices and build more efficient facilities than individual distribution cooperatives could on their own. This results in lower cost, more reliable electricity for our members.



Bridging communities through member programs

We want to help members make electrification and efficiency upgrades accessible for all so we use rebate, education and financing programs. These options and incentives benefit our members and their communities and consumers. Together, we can Electrify and Save®.

Our programs </programs>



Empowering Cooperatives: Inside Mesa Hotline School's Dedication to Excellence





</empowering-cooperatives-inside-mesa-hotline-schools-dedication-excellence>

Every May, over 500 line workers, teachers and volunteers gather in Grand Junction, Colorado at the Mesa Hotline School for the two-week annual learning event. The school attracts participants from across the United States, emphasizing safety and reliability in electrical transmission and distribution. It's an energetic and transformative learning experience with the aim of equipping people with the knowledge and skills needed to keep the lights on for the communities they serve.

Read more > </empowering-cooperatives-inside-mesa-hotline-schools-dedication-excellence>

The Power of Collaboration - Electric Engines for a Cleaner Future

</power-collaboration-electric-engines-cleaner-future>

As a cooperative, we know that when people come together, we can achieve greater results than any one of us could have done alone. Such was the case in the electrification of the Dahlia Station, a key depot along the Amarillo-to-Albuquerque pipeline managed by NuStar Energy – one of the nation's largest independent liquids terminal and pipeline operators.

Read more > </power-collaboration-electric-engines-cleaner-future>

Communities Win with Rebates: Two Business Owners Make Rebates Work for Them</communitieswin>

Cooperatives like Big Horn are always looking for ways to better serve their member-owners. One way of doing that is by offering rebates for energy-efficient home and business upgrades.

Read more > </communitieswin>

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English

©2026 Tri-State Generation and Transmission Association, Inc. Power supplier to the rural west.

A Touchstone Energy® Cooperative

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Exhibit to
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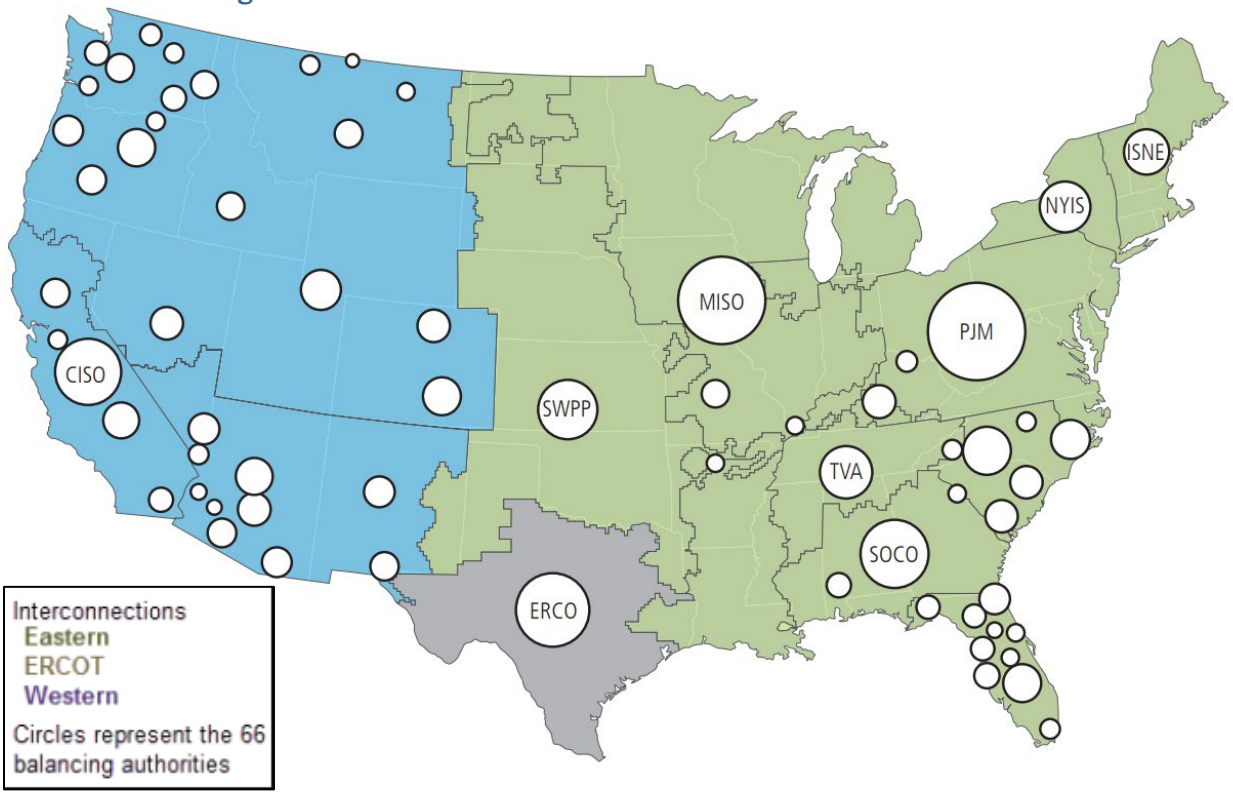
Exhibit 2-115:
Department Explainer on Balancing Authorities

How it Works: The Role of a Balancing Authority

There are many key players in the electricity supply chain that work together to reliably supply power to electric customers. One key player is the balancing authority, which manages the operation of the electric system within a specific geographic area. There are more than 60 balancing authorities in the U.S., and they are typically either utilities, Power Marketing Administrations (PMAs), or a group of utilities that have formed regional entities called regional transmission organizations (RTOs) and independent system operators (ISOs).[1]

Exhibit 1. Balancing Authorities Across the U.S.



Source: Quadrennial Energy Review: Transforming the Nation's Electricity System: The Second Installment of the QER (January 2017)

See EIA Hourly Electric Grid Monitor for interactive map.

A balancing authority ensures that power system demand and supply are always balanced, which maintains safe and reliable operation of the power system. If supply falls below demand, it can cause a drop in frequency below the stable system frequency, risking significant permanent physical damage to electrical equipment and prolonged grid-wide blackouts. During such situations, balancing authorities may direct utilities to "shed load" (i.e., implement rolling blackouts) to bring supply and demand into balance.

[1] U.S. Energy Information Administration Form 930

Balancing authorities also manage transfers of electricity (interchanges) with other balancing authorities and use economic dispatch to optimize the use of various generating units to minimize real-time costs. Balancing authorities are responsible for maintaining operating conditions under mandatory reliability standards issued by the North American Electric Reliability Corporation (NERC) and approved by the U.S. Federal Energy Regulatory Commission (FERC).

ISOs/RTOs

The formation of ISOs and RTOs came at the encouragement of FERC (click to read on FERC orders and RTOs/ISOs) to operate the transmission system independently of—and foster competition for electricity generation among—wholesale market participants. ISOs/RTOs do not own transmission or generation assets, nor do they directly serve or establish pricing for retail electric customers. They are not a part of any government, so they also do not have any enforcement authority over any electric generation facilities, electric transmission or distribution lines, or substations.[2]

The role of ISOs and RTOs are similar, but ISOs do not meet the minimum requirements specified by FERC to hold the designation of RTO or have not applied for the status. An ISO operates the region's electricity grid, oversees the region's wholesale electricity markets, and provides reliability planning for the region's bulk electricity system. RTOs perform the same functions as the ISOs but have greater responsibility for planning near- and long-term transmission maintenance, upgrades, and expansion projects in collaboration with the actual transmission system owners. Utilities in areas where there is no RTO or ISO serve all these functions for their own territories. There are currently three ISOs and four RTOs that operate within the U.S.:

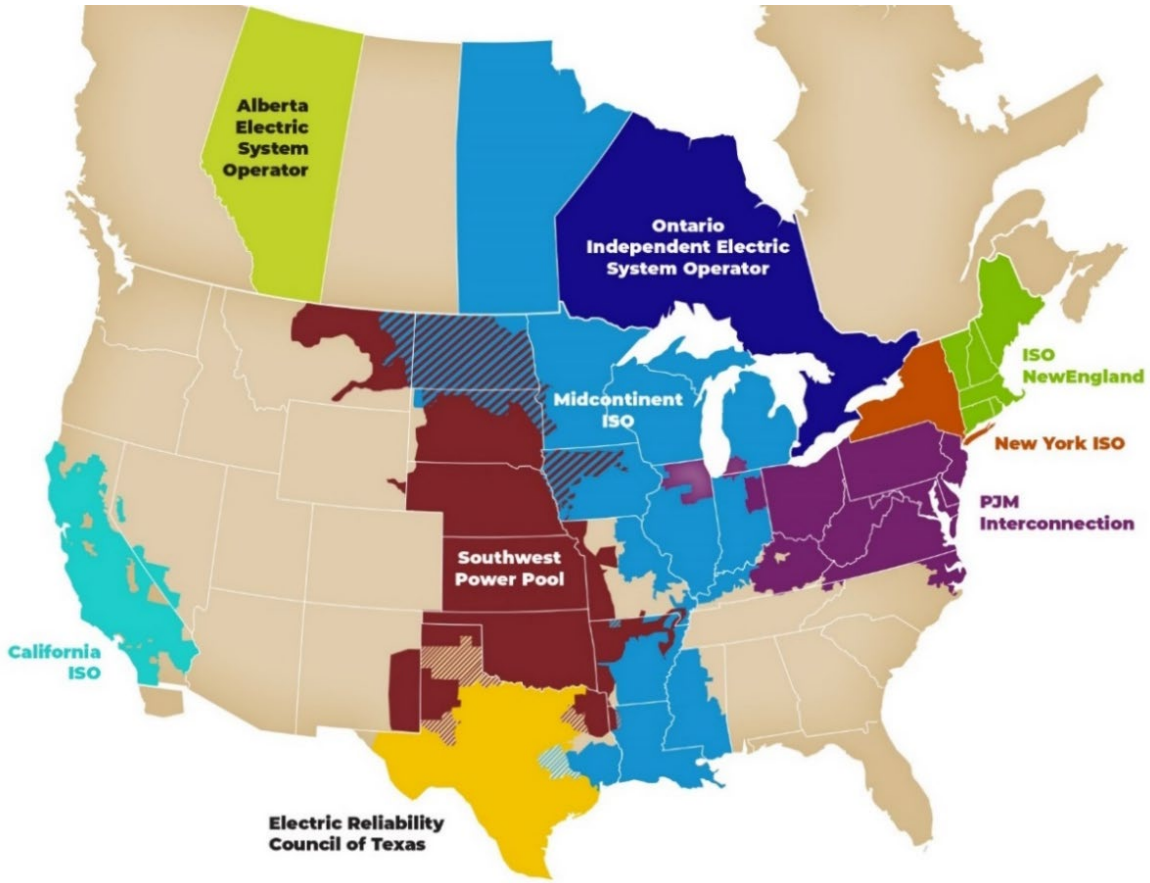
Independent System Operators (ISO)	California ISO	CAISO
	New York ISO	NYISO
	Electric Reliability Council of Texas[3]	ERCOT
Regional Transmission Operator (RTO)	PJM Interconnection	PJM
	Midcontinent Independent System Operator	MISO
	Southwest Power Pool	SPP
	ISO New England	ISO-NE

Although two-thirds of the nation's electricity load is served in RTO/ISO regions (as can be seen from the map in Exhibit 2), there are large sections of the United States—particularly in the Southeast and the West—where there is no ISO or RTO. Electric utilities in these areas are still subject to the same reliability regulations under NERC/FERC.

[2] The North American Electric Reliability Corporation (NERC) issues and enforces reliability standards for balancing authorities, which are approved by the U.S. FERC and, in Canada, by Canadian regulators. NERC relies on Regional Entities to enforce reliability standards with bulk power system owners.

[3] ERCOT does not fall under FERC authorities over interstate transmission and wholesale markets since it is entirely within the state of Texas and is not interconnected with the rest of the region. ERCOT is still subject to NERC oversight and FERC regulation for reliability.

Exhibit 2. Map of ISO/RTO Territories



Source: ISO/RTO Council

Grid Operation

Balancing authorities function as grid operators that dispatch electric generators to provide reliable power at the lowest cost. Because each generator has differing variable costs, generation is dispatched using the least costly generator first, in a way that is consistent with the relevant constraints of the transmission system and reliability requirements. Traditional utilities that are balancing authorities manage economic dispatch within their service areas, while ISOs and RTOs determine economic dispatch using bid-based markets where buyers and sellers bid for or offer generation. The dispatch process occurs in two phases: day-ahead unit commitment for the next day's dispatch, and real-time system dispatch.

- **Day-Ahead Commitment:** Balancing authorities decide which generating units should be committed to be online for each hour of the next 24-hour period. In selecting the most economic generators to commit, operators consider forecasted load requirements and each unit's physical operating characteristics, such as how quickly output can be changed, maximum and minimum output levels, and the minimum time a generator must run once it is started. Load forecasting uses mathematical models to predict demand across the balancing authority's footprint, incorporating weather/climate, past energy consumption data, typical behavioral patterns, and economic activity.
- **Real-Time System Dispatch:** Balancing authorities must decide the appropriate level at which each available resource from the day-ahead commitment should be operated, given the real-

time load and other grid conditions, so that overall production costs are minimized. Actual demand will vary from the forecasted load and the balancing authorities must adjust the actual dispatch to match. As part of real-time operations, demand, generation, and interchange (imports and exports) must be continually kept in balance to maintain the stable system frequency. This is typically done by automatic generation control to change the generation dispatch as needed.

Contingency Resources and Capacity Markets

Grid operators maintain excess contingency resources in the form of power generation capacity, intertie[4] capacity, and electricity storage to ensure that electricity supply is always available to meet anticipated peak demand. This "reserve margin" is required to meet Federal and State reliability requirements and can be used to provide a cushion or buffer during unexpected demand spikes, or potential loss of supply or transmission resources. If reserve margins fall below specified levels, grid operators may initiate emergency procedures to use additional resources—such as ancillary services and load management measures—that are only available during scarcity conditions.

RTO/ISOs typically use capacity markets to ensure that there are sufficient resources available to serve anticipated load and meet reserve margin requirements. Capacity markets may use auctions to lock in prices for electric capacity from generation resources in advance of the need. Capacity markets can also be marketplaces for demand response, in which customers reduce demand when called upon in exchange for capacity payments similar to what generators receive. Capacity prices vary by location and timing of capacity commitments, and typically not by size or fuel type. ISO-NE, PJM, MISO, and NYISO operate capacity markets, while other ISOs currently do not.

Ancillary Services

Ancillary services are intended to maintain electric reliability and support electricity transmission. They mainly include services related to frequency stability like operating reserves; services related to voltage stability like reactive power support and voltage control, and other services like black start generation. Ancillary services are becoming more important for variable energy resources—such as wind and solar power—due to their production variability and forecast uncertainty. Within ISOs/RTOs, ancillary services are typically procured through bid-based auction markets, tariff fixed or formula-based rates, or competitive solicitations.

Operating reserves are needed to quickly restore load and generation balance when a supply resource trips offline. Operating reserves are provided by dispatchable generating units increasing output or demand-side resources reducing demand to restore balance. There are three types:

1. **Spinning reserves** are provided by generators that are online (synchronized to the system frequency) with some spare capacity and capable of increasing its electricity output within a short time period (within 10 minutes).
2. **Non-spinning reserves** are provided by generating units that are not necessarily synchronized to the power grid but can be brought online within a short time period (within 10 minutes). Non-spinning reserves can also be provided by demand-side resources.
3. **Supplemental reserves** are provided by generating units that can be made available within a longer time period (between 10 to 30 minutes).

[4] An intertie is an interconnection permitting passage of current between two or more electric utility systems

Black start generating units—primarily hydroelectric facilities and diesel generators—can transition from a shutdown condition to an operating condition and start delivering power without any outside assistance from the electric grid. These are the first facilities to start up in the event of a system failure or blackout to restore the rest of the grid.

Emergency Measures

Balancing electricity supply and demand to preserve grid stability is a critical function of balancing authorities. If supply falls below demand, it causes a frequency drop on the electrical grid below the stable system frequency, which can cause vibrations resulting in significant permanent physical damage to electrical equipment. As the frequency drops below safe operating levels, many generators will automatically disconnect from the grid for self-protection. As generators and other electrical equipment shut down, this further reduces electricity supply, causing the system frequency to drop even further.

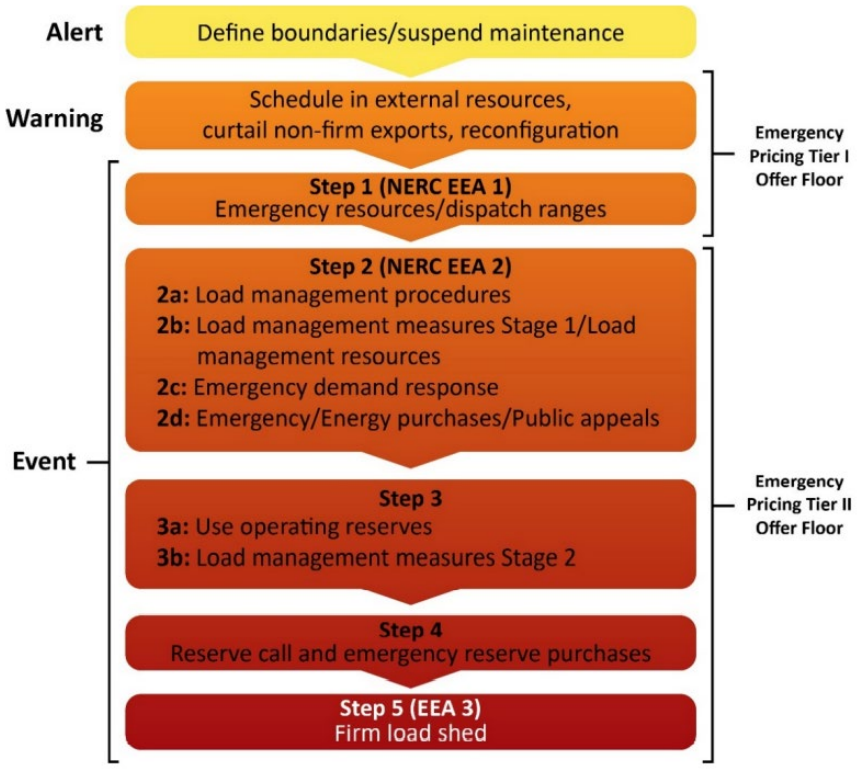
If no interventions are taken to stabilize the grid, this cascading effect can lead to collapse of the electricity grid and prolonged grid-wide blackout. During the February 2021 Extreme Cold & Winter Weather Incident, significant electricity generation assets went offline in the ERCOT region, causing a frequency drop that triggered additional generation loss. To rebalance supply and demand to stabilize the grid, ERCOT had to quickly shed substantial load, calling on its member utilities to proactively cut off electricity to their customers on a rotating basis over a period of three days. Although grid conditions in neighboring balancing areas were not as severe as in ERCOT, both MISO and SPP implemented brief periods of load shedding during the event.

When a balancing authority predicts there will be a shortage of electricity, there are response measures they can take to rebalance supply and demand. Each balancing authority has its own response protocol with response measures increasing as the anticipated shortage becomes more severe. The first step is typically to issue an alert to market participants describing the situation and suspending non-essential work (such as regular maintenance) to maximize the availability of generation and transmission resources. Balancing authorities may also issue Conservation Alerts, in which they ask consumers to voluntarily reduce their energy usage to reduce demand, especially during peak demand hours. Examples of consumers reducing energy usage include adjusting their thermostats, avoiding using large electric appliances, turning off non-essential lights, etc.

If initial response measures are insufficient to rebalance supply and demand, then a balancing authority will begin declaring energy emergency alerts (EEAs). EEAs have different levels depending on the event.

- At EEA Level 1, a balancing authority will typically call on all available power supplies (regardless of economics), including power from other grids if available, and enable certain demand-side resource deployments.
- At EEA Level 2, a balancing authority will typically initiate demand response programs that shed load from large industrial customers that have contractually agreed. They will also typically make a public appeal for all customers to cut back on electricity consumption.

Exhibit 3. Emergency Alert Levels



Source: NERC

- At EEA Level 3, balancing authorities will typically order utilities to shed load and inform them how much load they individually need to shed, and each utility then sheds the load by disconnecting circuits around customers with firm contracts. These outages are often "rotated" through the utility's service territory with customers losing power for several hours at a time, although sometimes customers are without power for the entire event. During load sheds, utilities typically will not disconnect circuits serving critical customers (hospitals, water treatment plants, etc.).

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	)

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

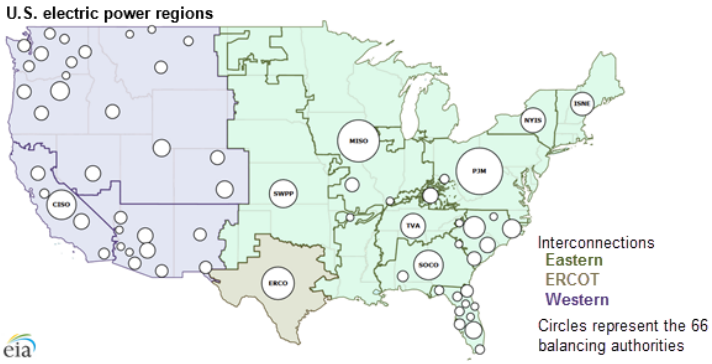
Exhibit 2-116:
EIA Explainer on Balancing Authorities

U.S. Energy Information Administration

Today in Energy

July 20, 2016

U.S. electric system is made up of interconnections and balancing authorities



Source: U.S. Energy Information Administration
Note: The locations of the electric systems are illustrative and are not geographically accurate. The sizes of the circles are roughly indicative of electric system size.

Electricity generated at power plants moves through a complex network of electricity substations, power lines, and distribution transformers before it reaches customers. In the United States, the power system consists of more than 7,300 power plants, nearly 160,000 miles of high-voltage power lines, and millions of low-voltage power lines and distribution transformers, which connect 145 million customers.

Local electricity grids are interconnected to form larger networks for reliability and commercial purposes. At the highest level, the United States power system in the Lower 48 states is made up of three main interconnections, which operate largely independently from each other with limited transfers of power between them.

- The Eastern Interconnection encompasses the area east of the Rocky Mountains and a portion of northern Texas. The Eastern Interconnection consists of 36 balancing authorities: 31 in the United States and 5 in Canada.
- The Western Interconnection encompasses the area from the Rockies west and consists of 37 balancing authorities: 34 in the United States, 2 in Canada, and 1 in Mexico.
- The Electric Reliability Council of Texas (ERCOT) covers most, but not all, of Texas and consists of a single balancing authority.

The network structure of the interconnections helps maintain the reliability of the power system by providing multiple routes for power to flow and by allowing generators to supply electricity to many load centers. This redundancy helps prevent transmission line or power plant failures from causing interruptions in service.

These interconnections describe the physical system of the grid. The actual operation of the electric system is managed by entities called balancing authorities. Most, but not all, balancing authorities are electric utilities that have taken on the balancing responsibilities for a specific portion of the power system. All of the regional transmission organizations in the United States also function as balancing authorities. ERCOT is unique in that the balancing authority, interconnection, and the regional transmission organization are all the same entity and physical system.

A balancing authority ensures, in real time, that power system demand and supply are finely balanced. This balance is needed to maintain the safe and reliable operation of the power system. If demand and supply fall out of balance, local or even wide-area blackouts can result.

Balancing authorities maintain appropriate operating conditions for the electric system by ensuring that a sufficient supply of electricity is available to serve expected demand, which includes managing transfers of electricity with other balancing authorities. Balancing authorities are responsible for maintaining operating conditions under mandatory reliability standards issued by the North American Electric Reliability Corporation and approved by the U.S. Federal Energy Regulatory Commission and, in Canada, by Canadian regulators. These operators monitor the grid to identify potential problems before a situation becomes critical.

Principal contributor: Sara Hoff

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

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

Exhibit 2-117:
NERC Emergency Operations

A. Introduction

1. **Title:** **Emergency Operations**

2. **Number:** **EOP-011-4**

3. **Purpose:** To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator

   4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.5 UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.6 Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

5. **Effective Date:** See Implementation Plan for Project 2021-07. As provided therein, each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner that receives notification from the Transmission Operator that it is required to assist in the mitigation of operating Emergencies in the Transmission Operator Area under Requirement R7 shall become compliant with Requirement R8 within 30 calendar months of the notification.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. Roles and responsibilities for activating the Operating Plan(s);

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Operator-controlled manual Load shed, undervoltage load shed (UVLS), or underfrequency load shed (UFLS) during an Emergency that accounts for each of the following:

1.2.5.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

1.2.5.2. Provisions to minimize the overlap of circuits that are designated for manual Load shed, UVLS, or UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES;

1.2.5.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

1.2.5.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions;

1.2.5.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity; and

1.2.6. Provisions to determine reliability impacts of:

1.2.6.1. Cold weather conditions; and

1.2.6.2. Extreme weather conditions.

M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has

been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. Capability and availability;

2.2.3.2. Fuel supply and inventory concerns;

2.2.3.3. Fuel switching capabilities; and

2.2.3.4. Environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load, and demand response;

2.2.8. Provisions for excluding critical natural gas infrastructure loads which are essential to the reliability of the BES, as defined by the Applicable Entity, as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;

2.2.9. Provisions for Transmission Operators to implement operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding in accordance with Requirement R1 Part 1.2.5; and

2.2.10. Provisions to determine reliability impacts of:

2.2.10.1. Cold weather conditions; and

2.2.10.2. Extreme weather conditions.

M2. Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator;

evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

R3. The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. Within 30 calendar days of receipt, the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

M3. The Reliability Coordinator will have documentation, such as dated emails or other correspondences that it reviewed, Transmission Operator and Balancing Authority Operating Plans, within 30 calendar days of submittal in accordance with Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator

communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

R7. Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

M7. Each Transmission Operator will have documentation, such as dated emails or other correspondences that it identified and notified Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners annually in accordance with Requirement R7.

R8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement a Load shedding plan. The Load shedding plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

8.1. Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding during an Emergency that accounts for each of the following:

8.1.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

8.1.2. Provisions to minimize the overlap of circuits that are designated for manual, undervoltage, or underfrequency Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;

8.1.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

8.1.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual

Load shed to situations where warranted by system conditions; and

8.1.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity.

8.2. Provisions to provide the Load shedding plan to the Transmission Operator for review.

M8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area will have a dated Load shedding plan(s) developed in accordance with Requirement R8 and evidence that the Load shedding plan(s) was provided to its Transmission Operator; evidence such as a review or revision history to indicate that the Load shedding plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Load shedding plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with the mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4.
- The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6.
- The Transmission Operator shall maintain evidence of compliance since the last audit for Requirement R7.
- The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner shall retain the current Load shedding plan, evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R8.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to implement it.
R2	N/A	The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to maintain it.	The Balancing Authority developed an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to have it reviewed by its Reliability Coordinator.	The Balancing Authority failed to develop an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to implement it.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	N/A	N/A	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator within 30 calendar days.	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator.
R4	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators, but failed to notify within 30 minutes from the time of receiving notification.	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.
R6	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Alert.
R7	N/A	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities more than one, but fewer than 30 days late.	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late.	The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. OR The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR more of those entities 60 days or more late.
R8	N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to maintain it in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to provide it to its Transmission Operator in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop a Load shedding plan(s) in accordance with Requirement R8. OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to implement it in accordance with Requirement R8.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by the NERC Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.
1	November 19, 2015	FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	
2	June 11,2021	Adopted by the NERC Board of Trustees	Revised under Project 2019-06
2	August 24,2021	FERC approved EOP-011-2. Docket Number RD21-5-000	
3	October 26, 2022	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
3	February 16, 2023	FERC approved EOP-011-3. *N. Am. Elec. Reliability Corp.*, 182 FERC 61,094	
4	October 23, 2023	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
4	February 15, 2024	FERC Order issued approving EOP-011-4. Docket No. RD24-1-000	

Attachment 1-EOP-011-4
Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.

2. **Notification**. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use. Circumstances:**

   - The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.
   - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **EEA 2 — Load management procedures in effect. Circumstances:**

   - The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
   - An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 Declaration period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators**.**

2.3 Sharing information on resource availability. Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 Requesting Balancing Authority actions. Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

3. EEA 3 —Firm Load interruption is imminent or in progress. Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 Continue actions from EEA 2. The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

3.2 Declaration Period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre- Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.

3.4.2 Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

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

Exhibit 2-118:
Department Press Release on Centralia Order

An official website of the United States government Here's how you know

U.S. DEPARTMENT of ENERGY

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, 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 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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December 16, 2025

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Just Launched: A Critical Materials Career Map

December 17, 2025

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STRENGTHEN GRID RELIABILITY AND SECURITY EMERGENCY RESPONSE

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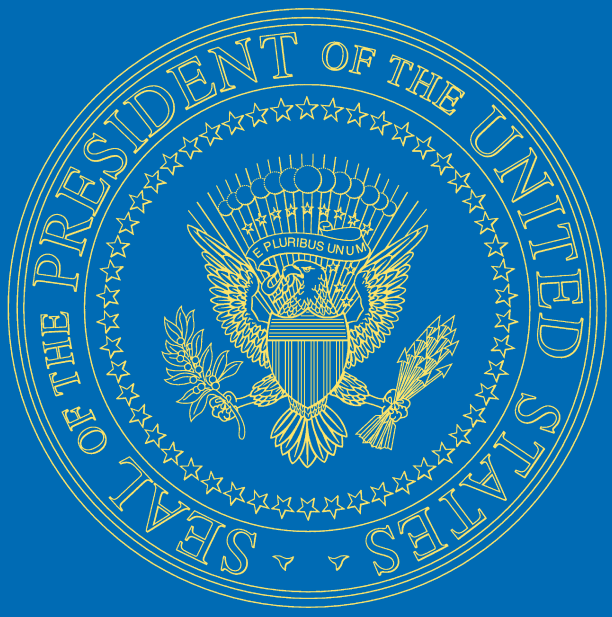
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

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

Exhibit 2-119:
2001 National Energy Policy

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

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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

ANN M. VENEMAN
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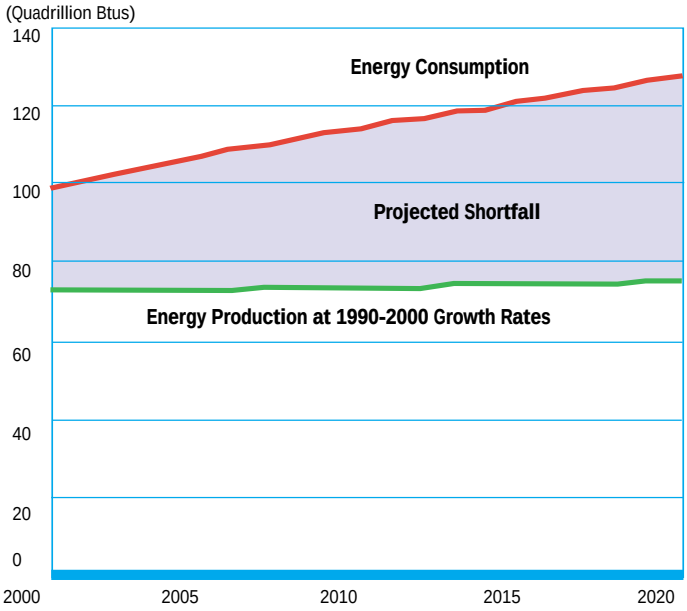
Overview

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.

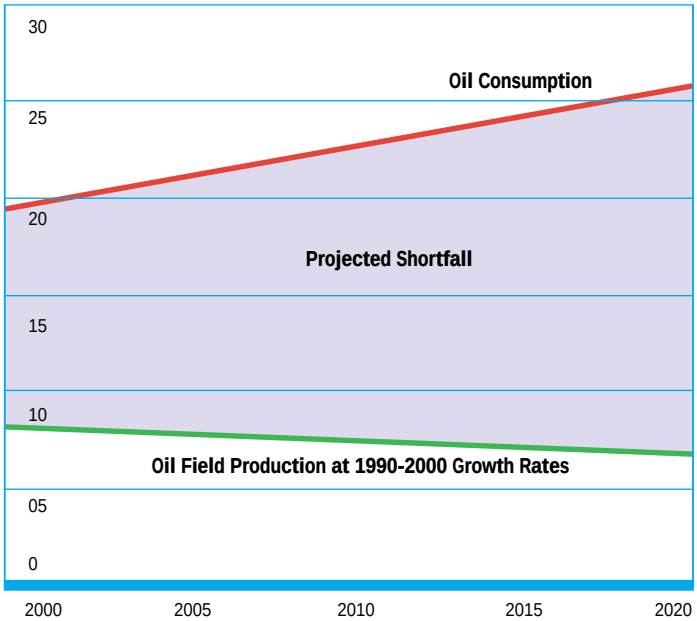
Increases on this scale will require preparation and action today. Yet America has not been bringing on line the necessary supplies and infrastructure.

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)



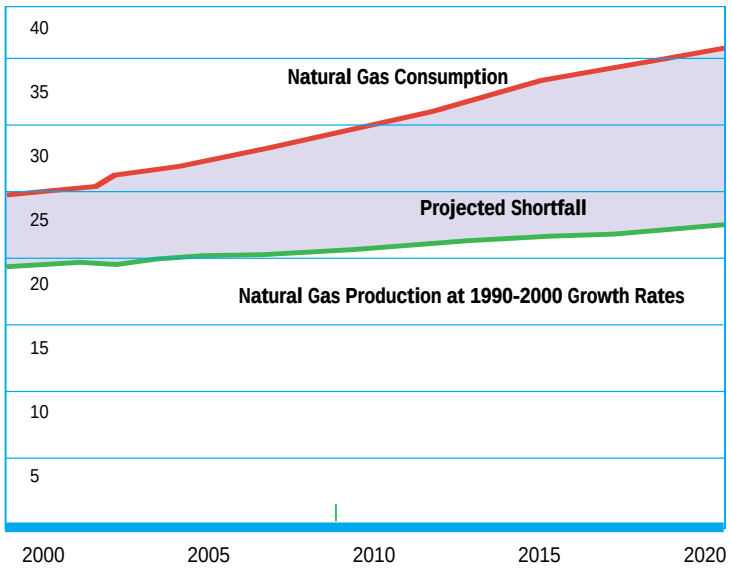
Over the next 20 years, U.S. oil consumption will grow by over 6 million barrels per day. If U.S. oil production follows the same historical pattern of the last 10 years, it will decline by 1.5 million barrels per day. To meet U.S. oil demand, oil and product imports would have to grow by a combined 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.

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

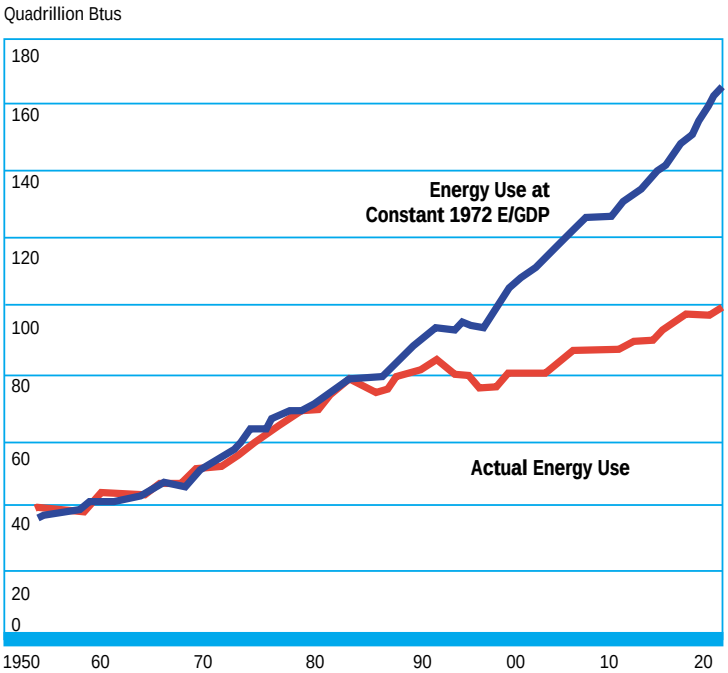
Americans share the goal of energy conservation. The best way of meeting this goal is to increase energy efficiency by applying new technology – raising productivity, reducing waste, and trimming costs. In addition, it holds out great hope for improving the quality of the environment. American families, 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.

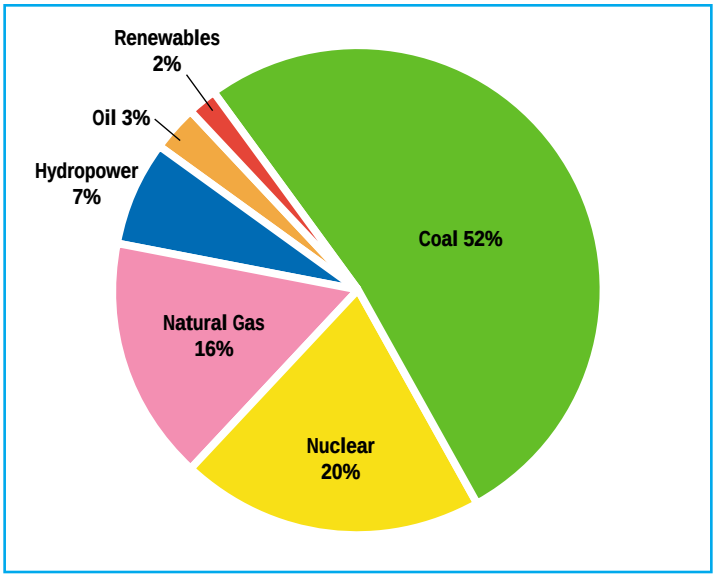
Nuclear power plants serve millions of American homes and businesses, have a dependable record for safety and efficiency, and discharge no greenhouse gases into the atmosphere. As noted earlier, these facilities currently generate 20 percent of all electricity in America, and more than 40 percent of 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



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.

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.

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.

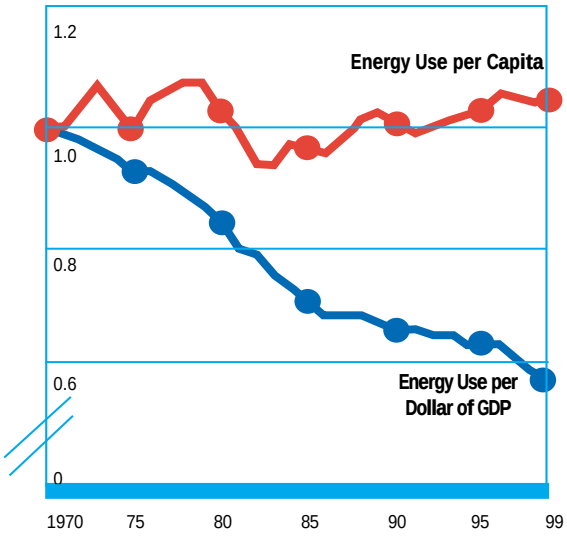
The impact that improvements in energy efficiency can have on energy supply markets grows over time. Electricity demand is projected to rise by 1.8 percent a year over the next 20 years, requiring the addition of some 393,000 MW of generation capacity. At the same time, energy efficiency is projected 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.

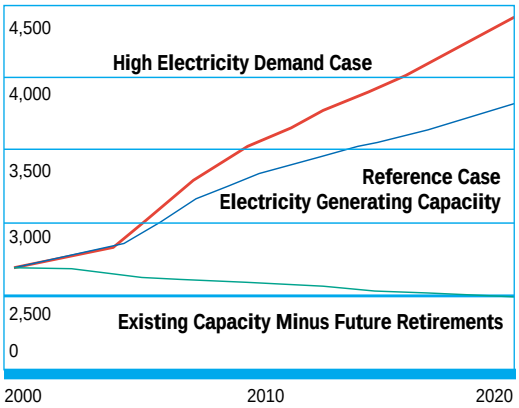
Electricity supply conditions in the Southeast are expected to be tight in the summer of 2001, much as they have been the previous two years. The Northeast may also face supply shortages. If the temperatures of the summer of 2000 had been normal rather than unseasonably cool, New York and New England 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.

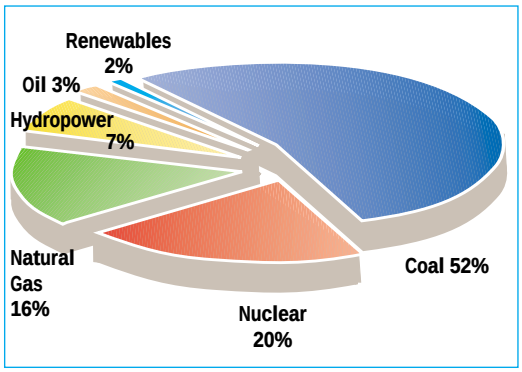
After peaking in 1982, coal prices have generally declined. This trend is projected to continue through 2020, reflecting an expanding shift into lower-cost western coal production and substantial increases in productivity. While coal is expected to remain the dominant fuel in meeting increasing U.S. 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.

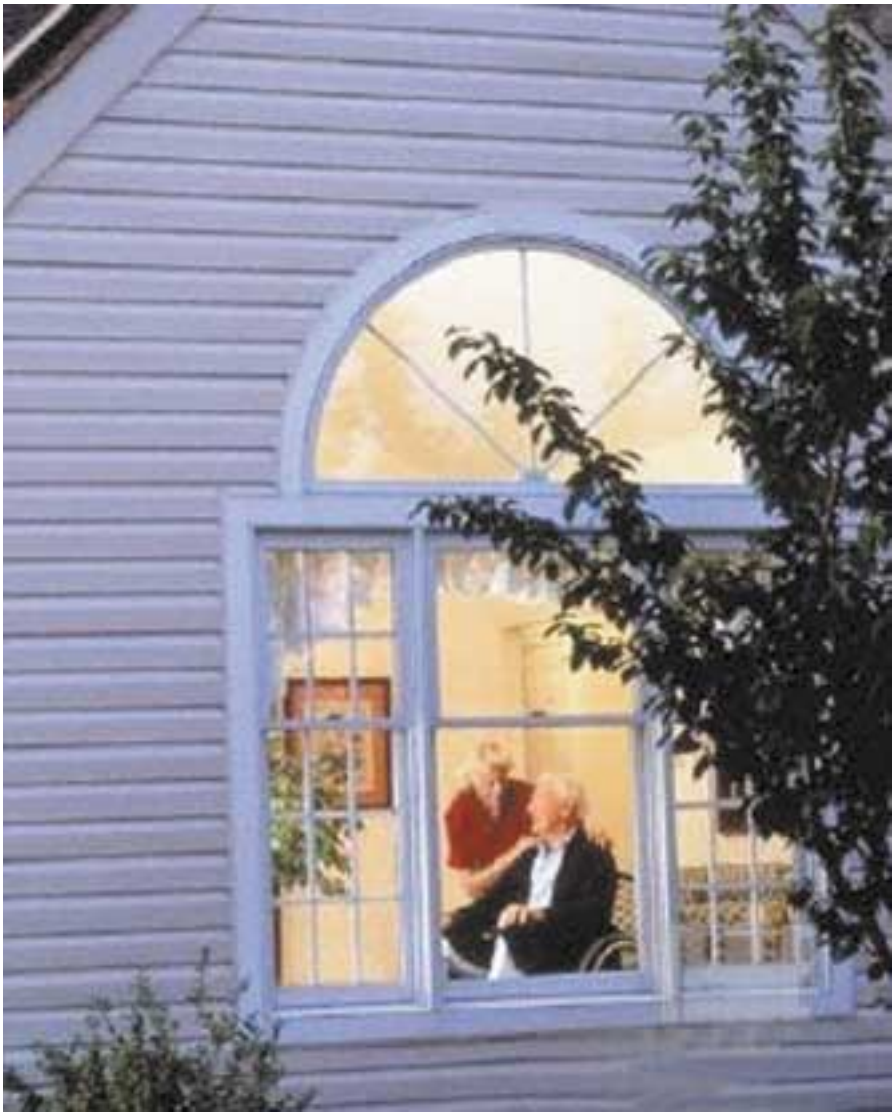
While the number of nuclear plants has declined due to retirements, nuclear electricity generation has steadily increased in recent years. Several factors have created a more favorable environment for nuclear energy: safe, standardized plant designs; an improved licensing process; effective safety oversight 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.

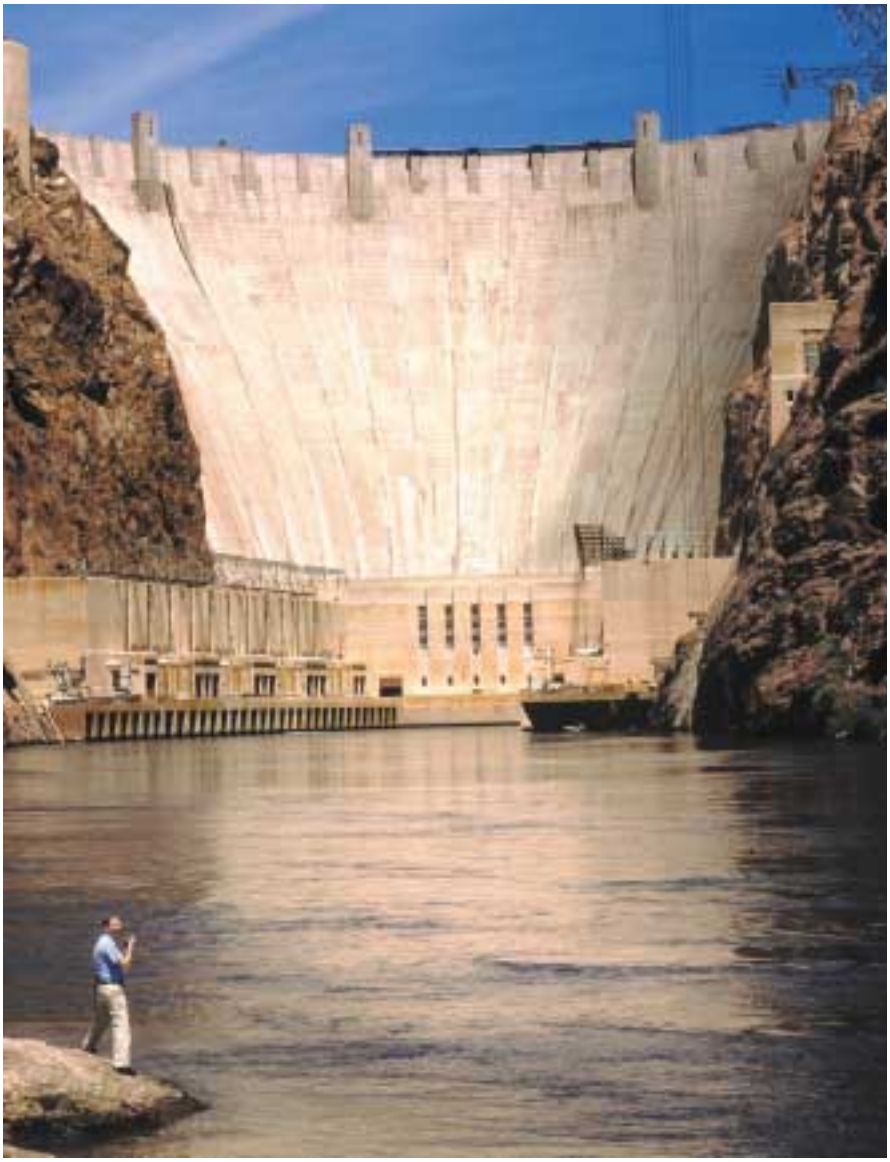
The most significant long-term challenge relating to natural gas is whether adequate supplies can be provided to meet sharply increased projected demand at reasonable prices. If supplies are not adequate, the high natural gas prices experienced over the past year could become a continuing problem, with 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.

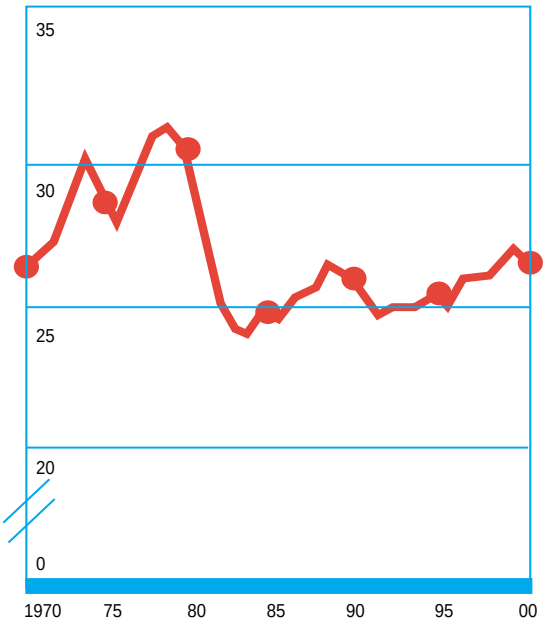
The most important long-term challenge facing renewable energy remains economic. Renewable energy costs are often greater than those of other energy sources. However, these costs have declined sharply in recent years, due to improved technology. If this trend continues, renewable energy growth will accelerate. 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.

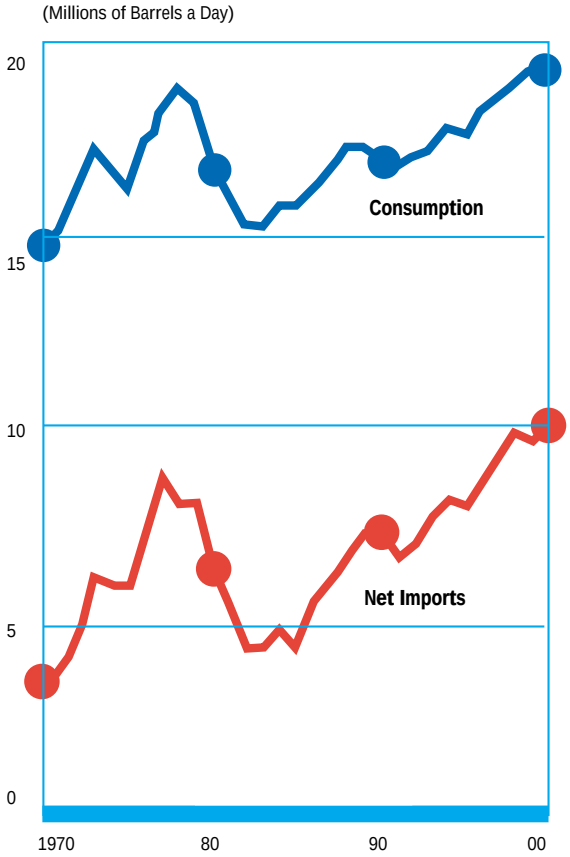
Source: U.S. Department of Energy, Energy Information Administration

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



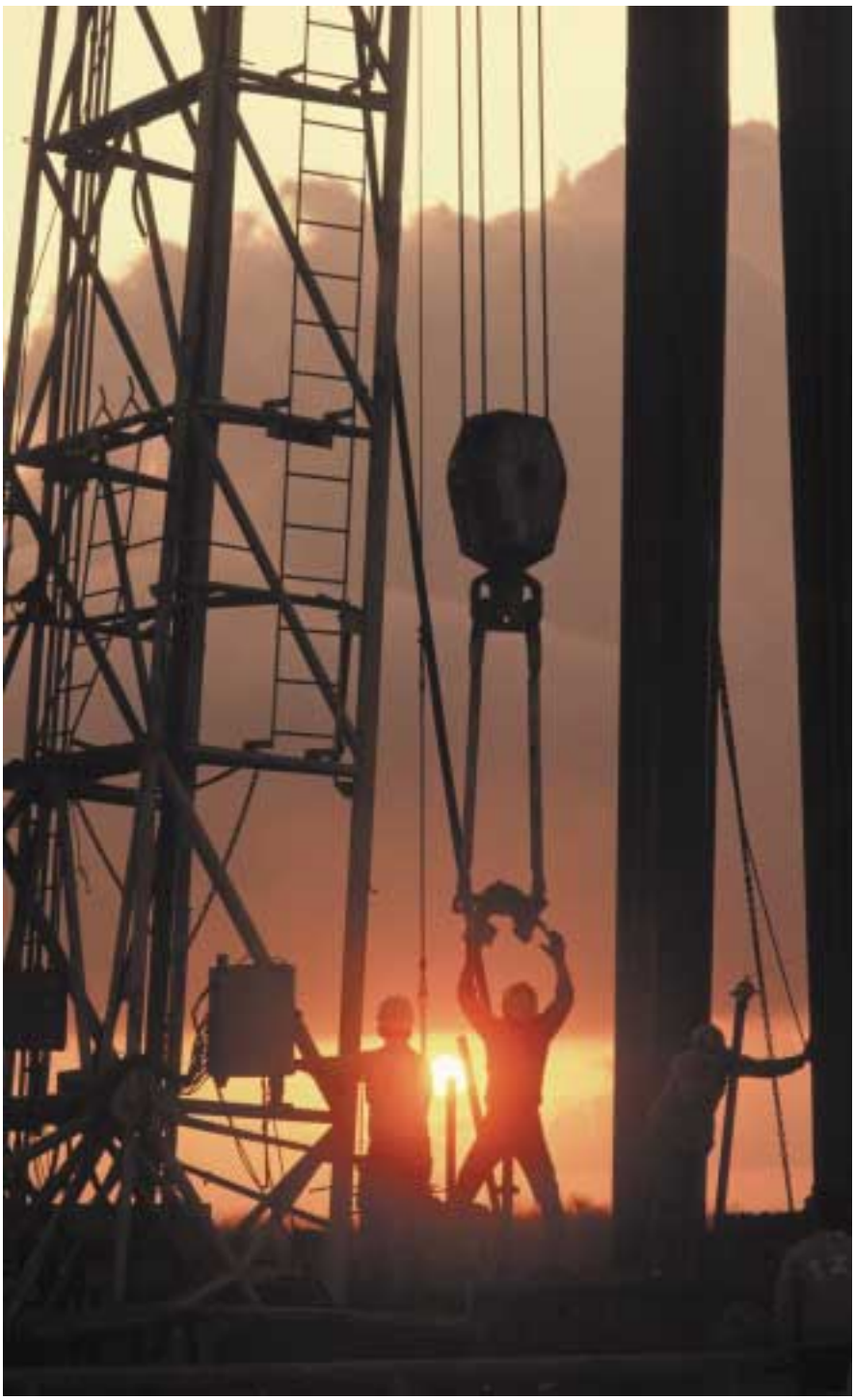
U.S. Department of Transportation

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

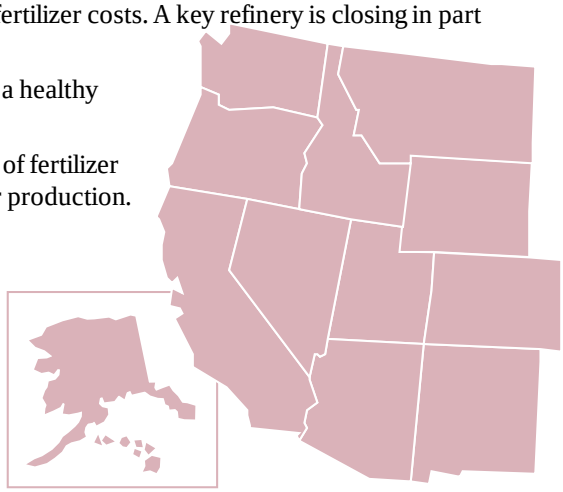
Midwest

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.

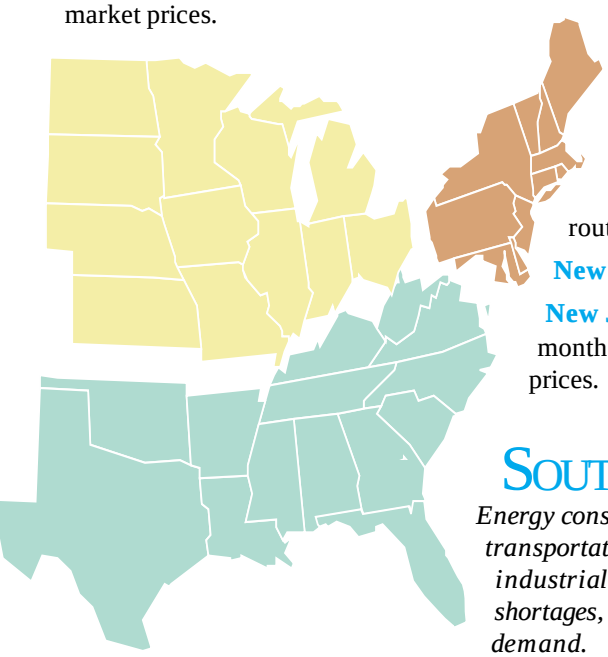
Hawaii's geographic isolation contributes to its many energy issues, such as importing 100 percent of its energy, its disproportionately high consumption of jet fuel and heavy reliance on tourism, and its dependence on imported oil for over 90 percent of its primary energy, the majority from sources 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

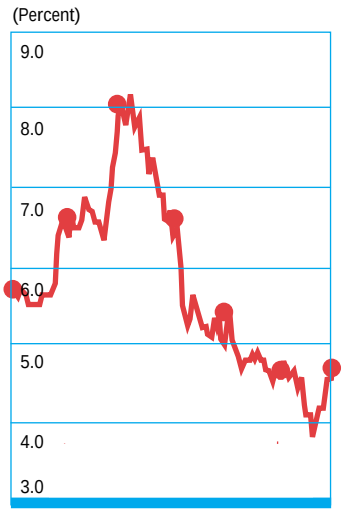
American families, communities, and businesses all depend on reliable and affordable energy for their health, safety, and livelihood. Energy is a critical component of nearly everything that affects our daily lives, from transportation to communication, from food production to medical services, and from 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.



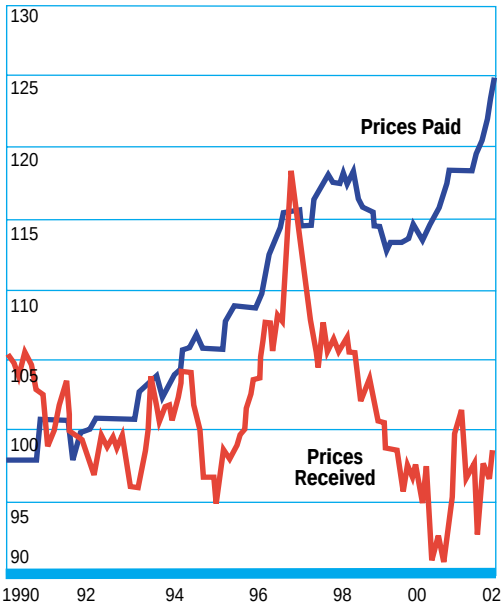
Farmers have been hit especially hard by higher fuel and oil prices, which accounted for over a third of the rise in the cost of running their farms.

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.

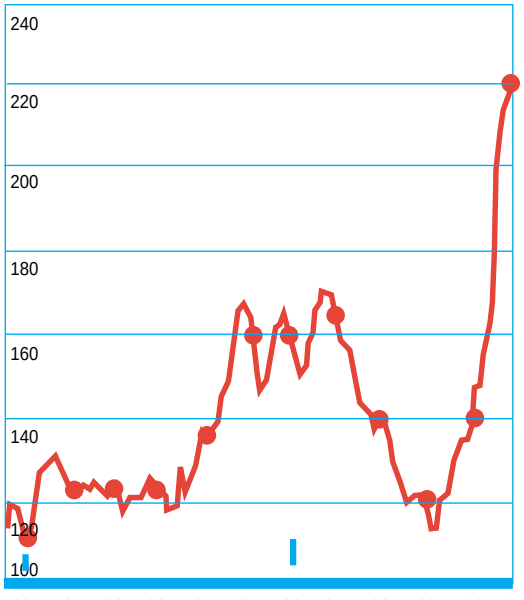
Agriculture

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.

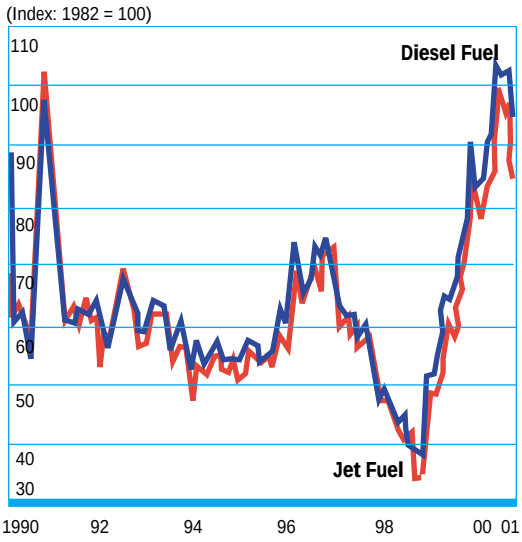
Taken together, fertilizer, fuel, and electricity costs for farmers are forecast to reach $24 billion for 2001, up by about 28 percent from $18.7 billion in 1999. This increase is about 9 percent of U.S. net cash farm income, and that share could be much higher for many individual commodities.

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.

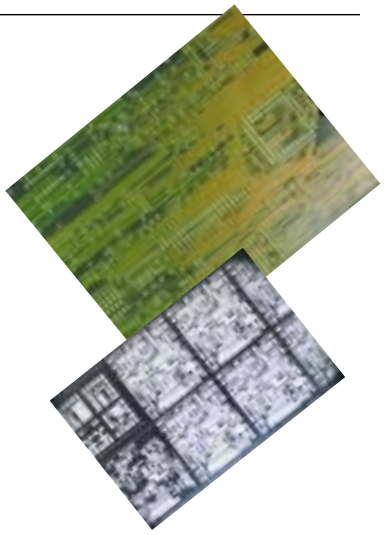
The power supply crunch in California and the West could affect the region's economy, as energy supply uncertainty could reduce investment in the region. California's troubles could also spill over to the national economy:

- 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.

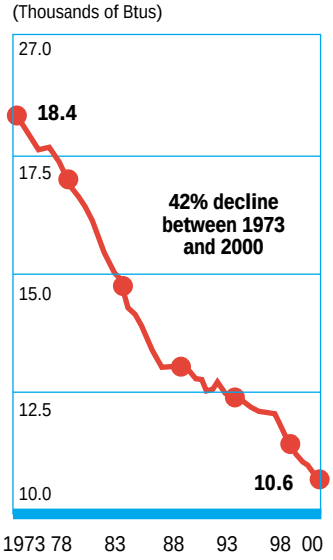
Improvements in Energy Efficiency Can Help

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.

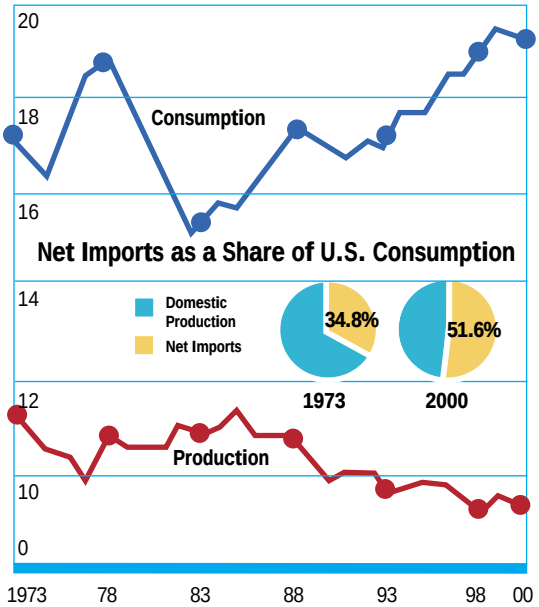
forts, regulatory action, market response, and a shift toward a service economy (Figure 2-5). Our improvements in energy efficiency have prevented our current energy problems from becoming worse.

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.

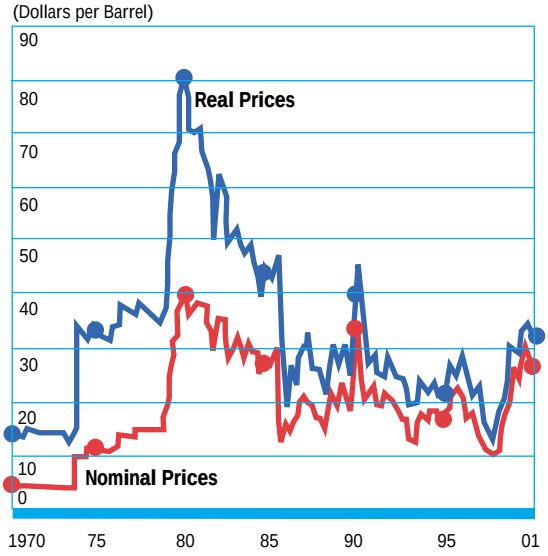
Figure 2-6
Dependence on Oil Imports Is Rising
(Millions of Barrels per Day)



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



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.

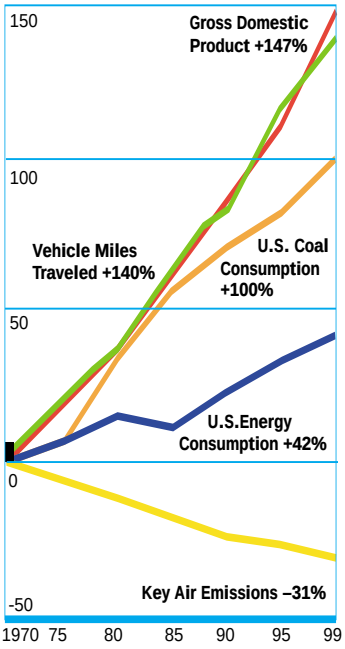
As U.S. energy needs grow, additional innovations will be necessary to continue improving environmental conditions and to meet new environmental challenges. As we improve the energy production and distribution system, all levels of government must ensure that regulatory systems protecting public health 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

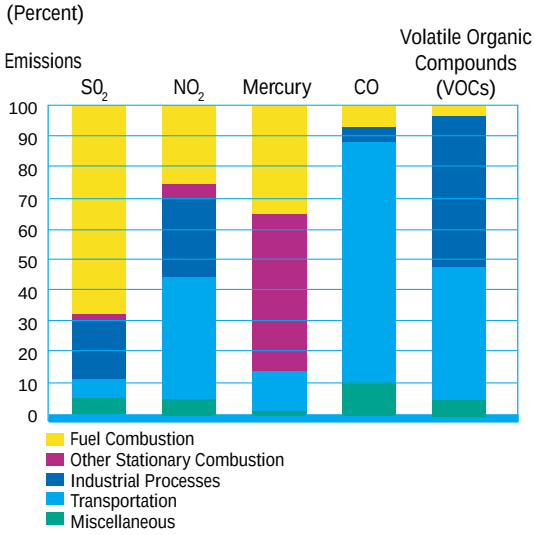
Emission control technologies and emission prevention not only decrease pollution but can also contribute to economic prosperity. Innovative emission control and prevention technology and increasingly efficient energy systems have developed at a brisk pace, increasing our ability to provide cleaner, 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.

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.

Recommendation:Ä

★ 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.



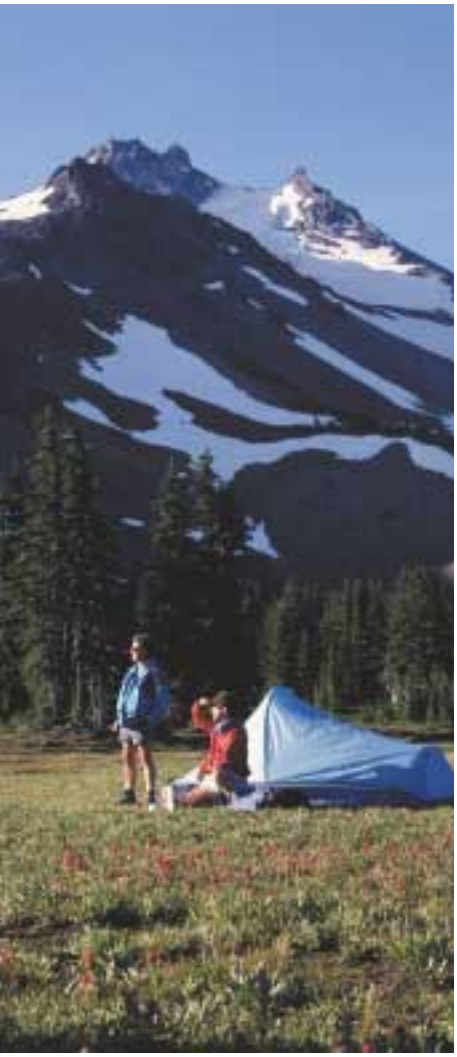
Technological advances and a strong commitment to environmental protection are enabling the healthy coexistence of our nation's diverse ecosystems with the development of energy resources.

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.

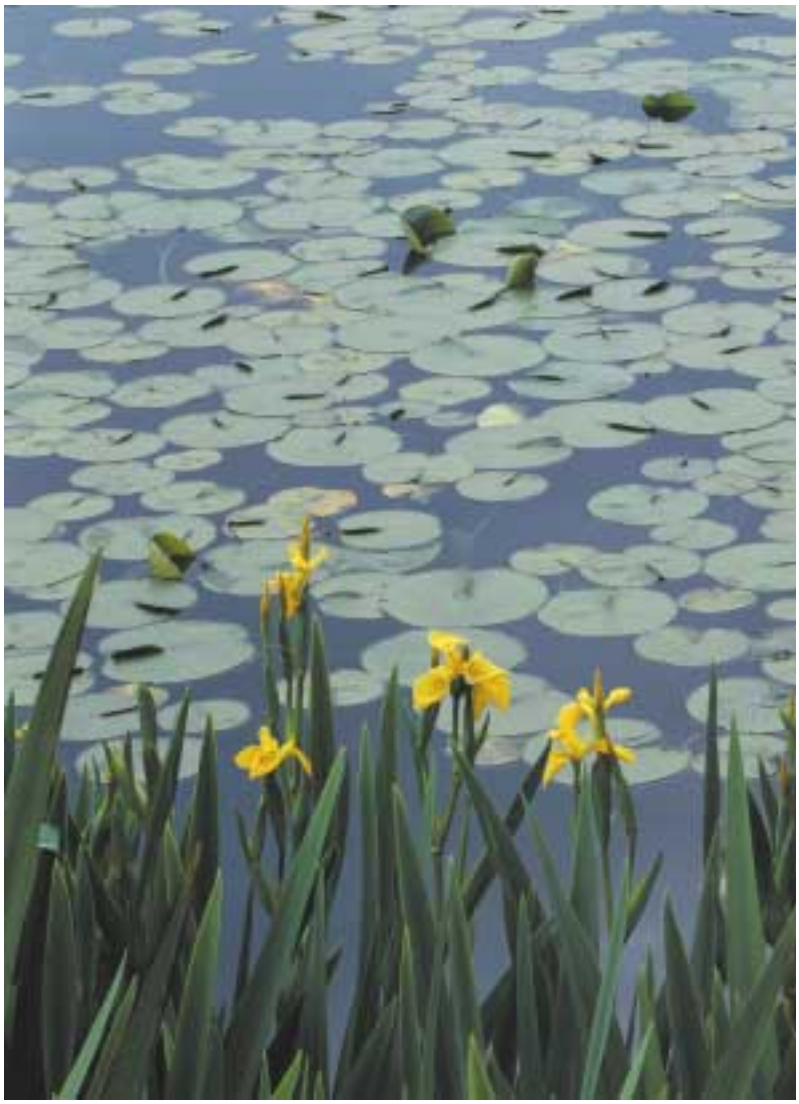
Regulatory Structure

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.
- 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.

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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.

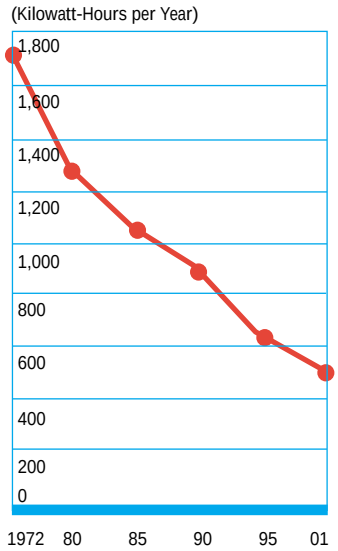
Conservation and energy efficiency are important elements of a sound energy policy. Improved energy efficiency is the result of many decisions, including those of individual consumers; manufacturers of cars and appliances; home builders; and state, federal, and local government officials. The federal 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.

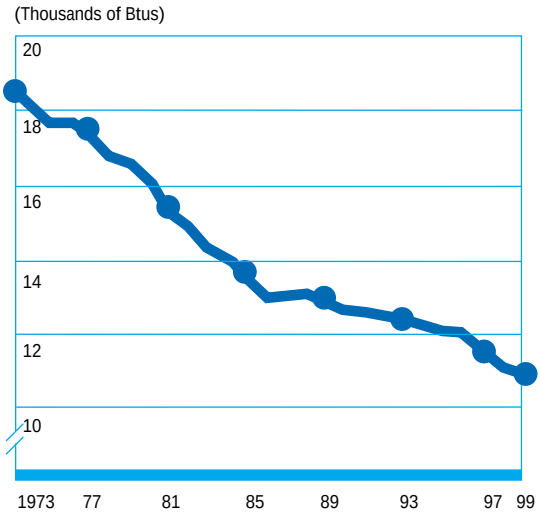
Sources: AHAM 2000 Major Home Industry Fact Book and BTS appliance standard.

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.

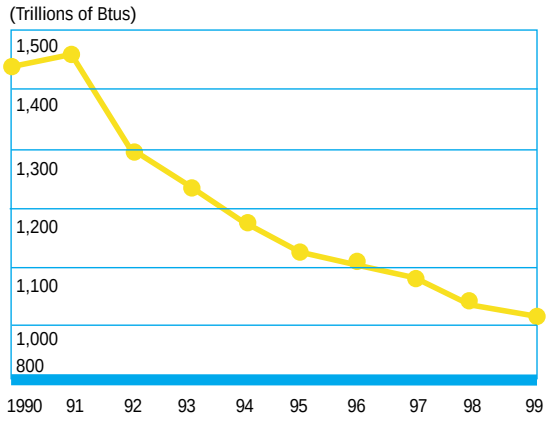
- Agencies should report to the President, through the Secretary of Energy, within 30 days of the conservation actions taken.

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

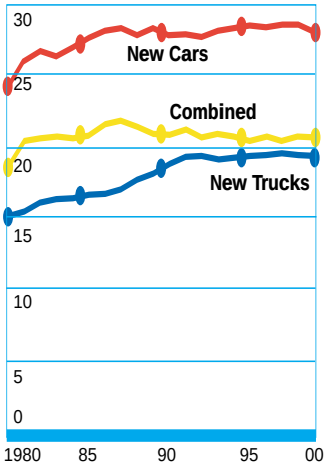
Because of the large economies of scale in automobile manufacturing, new technologies with limited early production runs often enter the market at higher initial costs. In this highly competitive international market, higher initial production costs can be a significant impediment to the introduction 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.

★ 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 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.

★ 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.

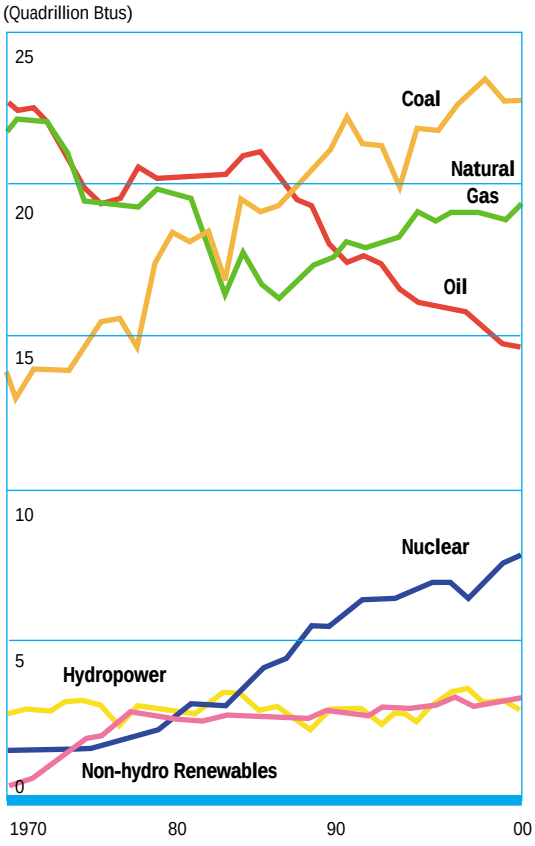
★ The NEPD Group recommends that the President direct the EPA Administrator to develop and implement a strategy to increase public awareness of the sizable savings that energy efficiency offers to homeowners across the country. Typical homeowners can save about 30 percent (about $400) a year on their 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

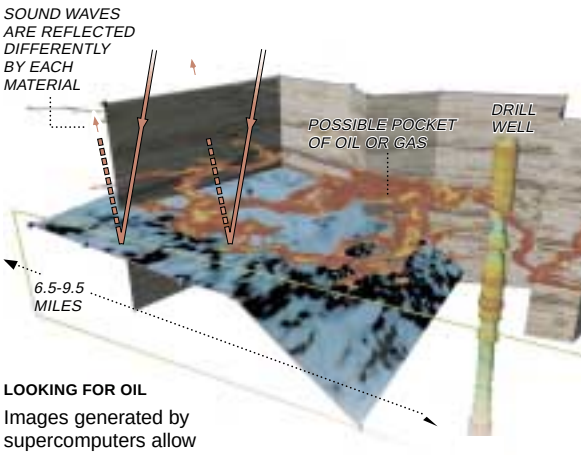
Oil and natural gas are the dominant fuels in the U.S. economy, providing 62 percent of the nation's energy and almost 100 percent of its transportation fuels. By 2020, the Energy Information Administration expects the United States will need about 50 percent more natural gas and one-third more oil to 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

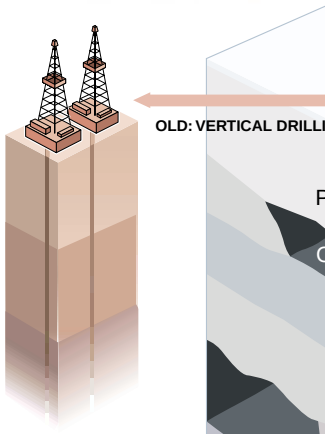
Remaining U.S. oil reserves are becoming increasingly costly to produce because much of the lower-cost oil has already been largely recovered. The remaining resources have higher exploration and production costs and greater technical challenges, because they are located in geologically complex reservoirs, (*e.g.*, deep water

Figure 5-2



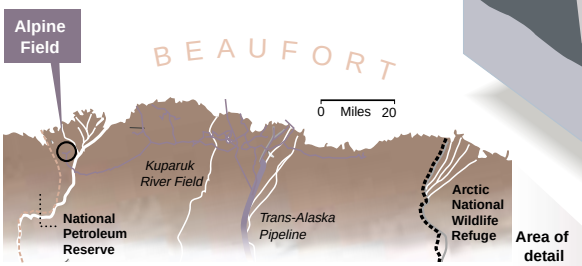
LOOKING FOR OIL

Images generated by supercomputers allow geologists to locate small pockets of oil or gas.



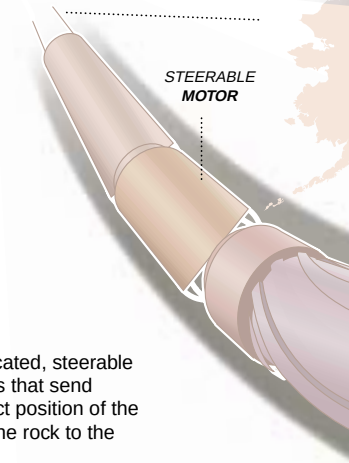
DRILLING TECHNOLOGY

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

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.

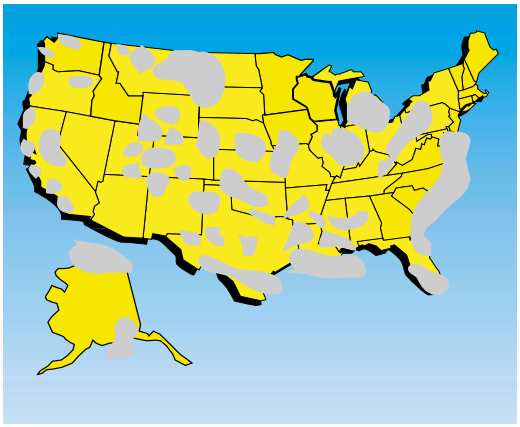
For each of these issues, opportunities exist to better coordinate, improve performance, and meet America's energy, public health, safety and environmental goals.

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.

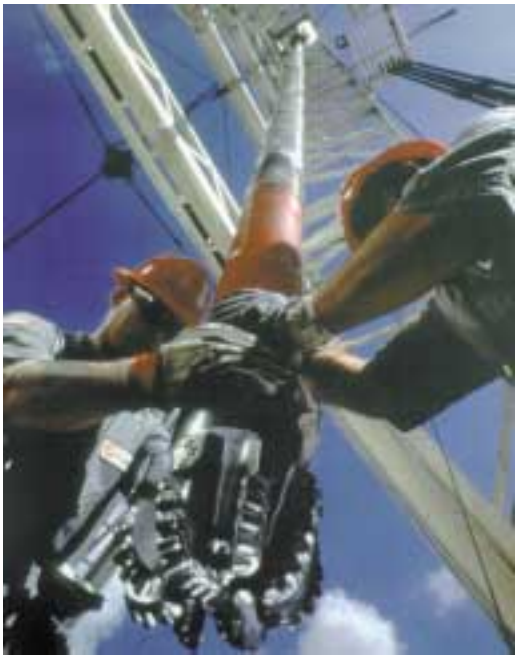
Recommendation:

★ 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

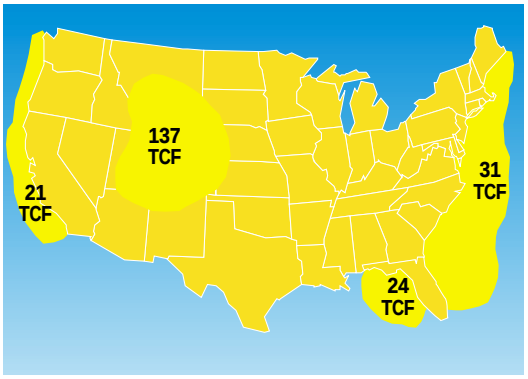
There is a significant potential for oil and gas resources on federal land in the lower 48 states as well. According to the most recent estimates from the USGS and the Minerals Management Service, oil resources underlying federal lands in the lower 48 states are estimated to be 4.1 billion barrels, and 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,

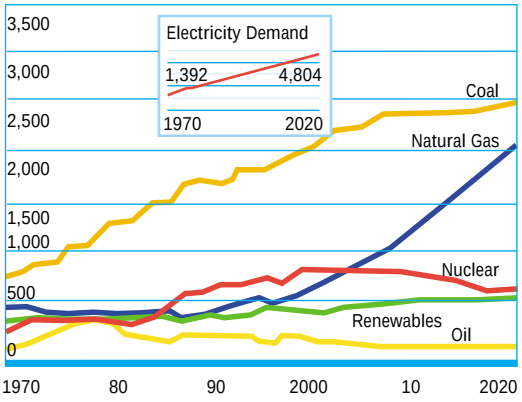
uncertainty over rules requiring air permits for certain modifications to power plants, and uncertainty over global and domestic efforts to reduce carbon dioxide emissions also play a role. This regulatory uncertainty discourages power producers from building coal power plants and is one reason the Unites 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.

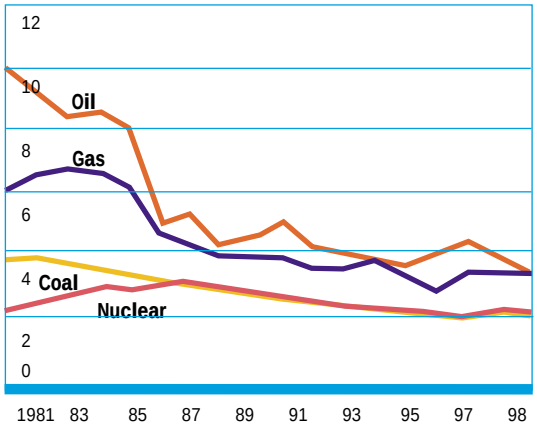
Advanced reactor technology promises to improve nuclear safety. One example of an advanced reactor design is the gas-cooled, pebble-bed reactor, which has inherent safety features. The industry has an interest in this and other advanced reactor designs.

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.é
Source: Utility Data Institute via the Nuclear Energy Institute.é



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.

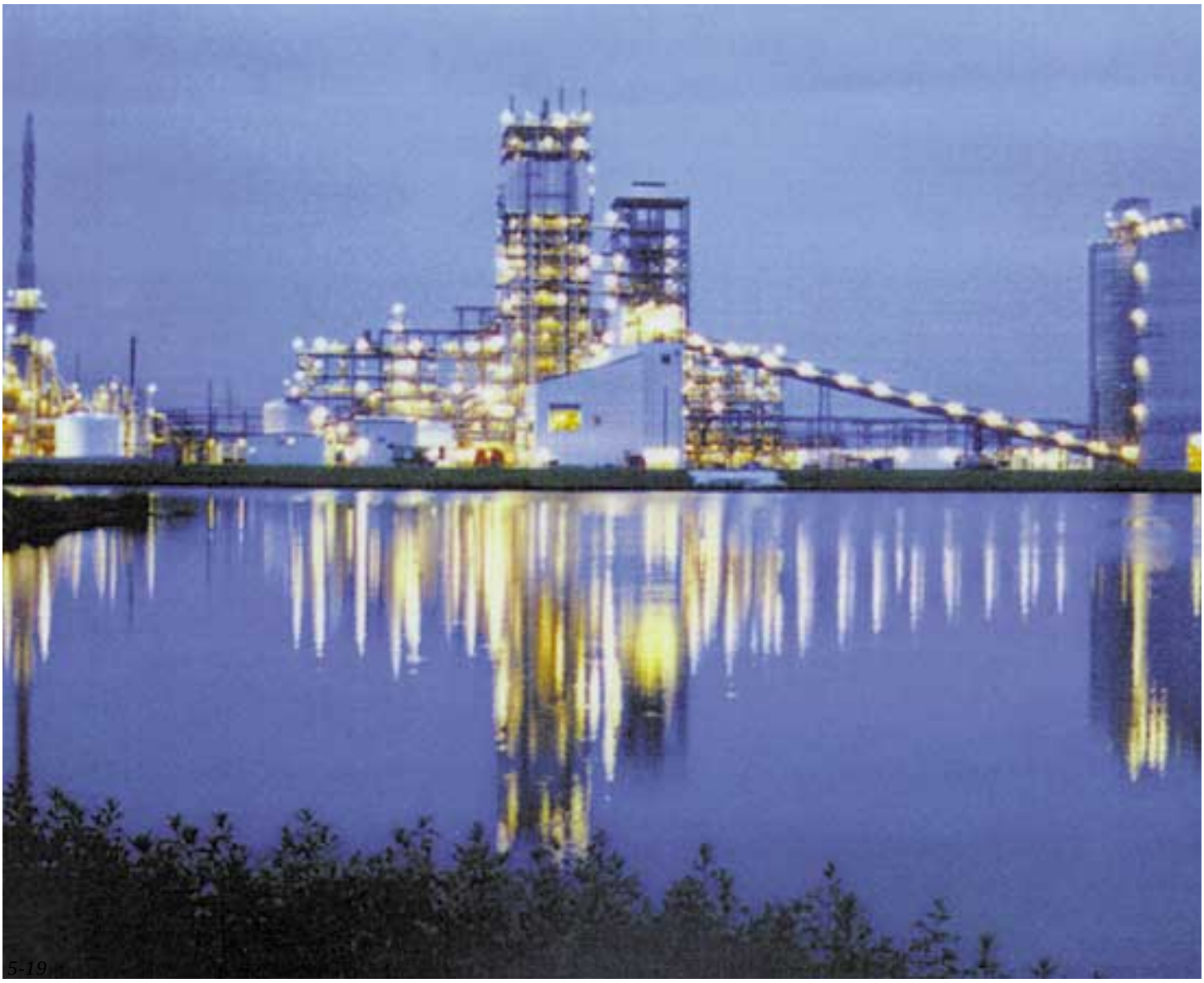
Oil

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.

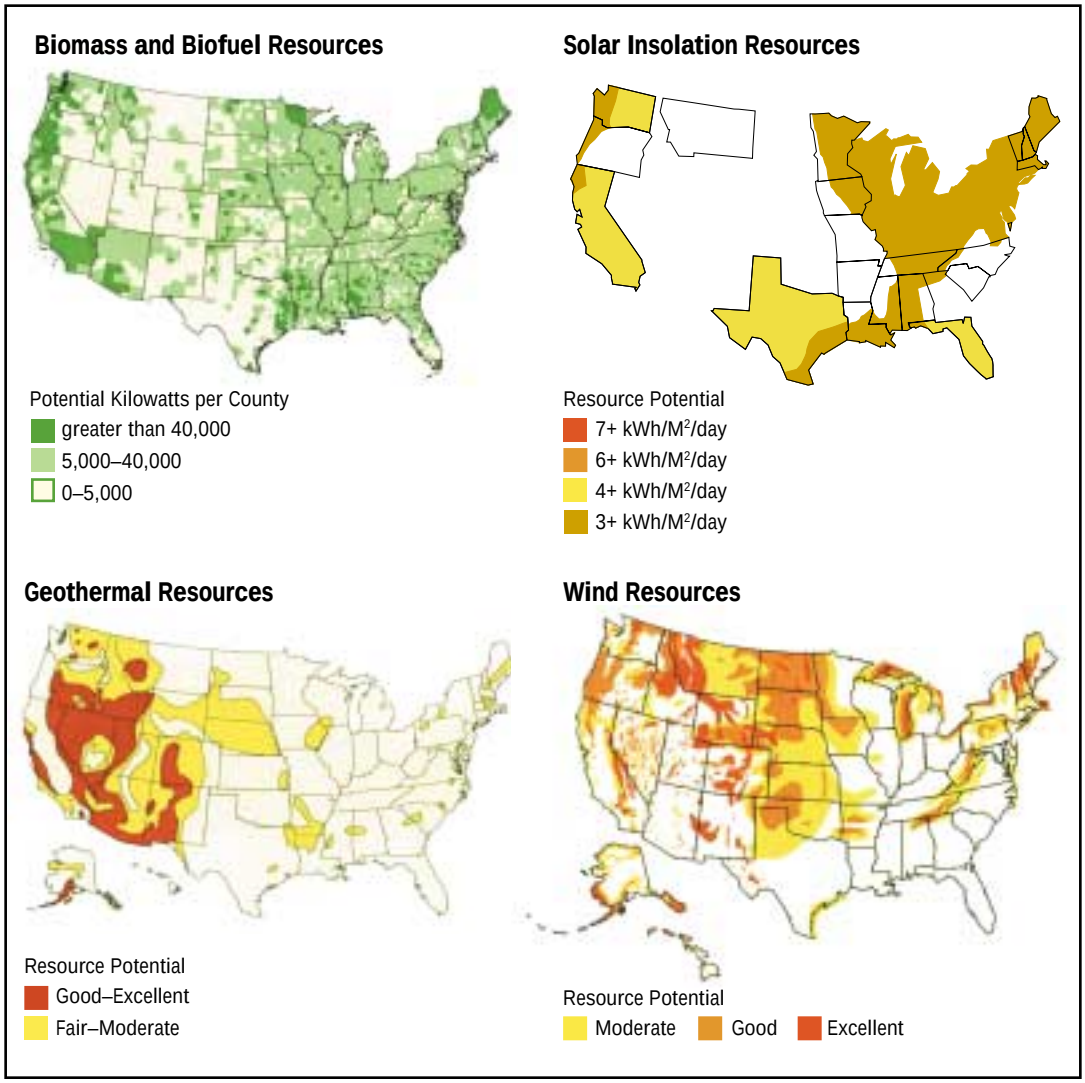


Renewable hydropower has long provided a significant contribution to the U.S. energy supply. Today, hydropower is competitive with other forms of conventionally generated electricity.



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

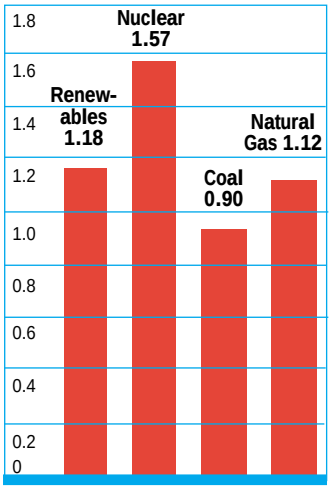
Non-hydropower renewable energy accounts for about 4 percent of current U.S. energy production, divided evenly be tween electricity generation and transpor tation fuels such as ethanol. Between 1990 and 1999, renewable energy generation grew by 29 percent, and renewable energy is projected to continue 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.

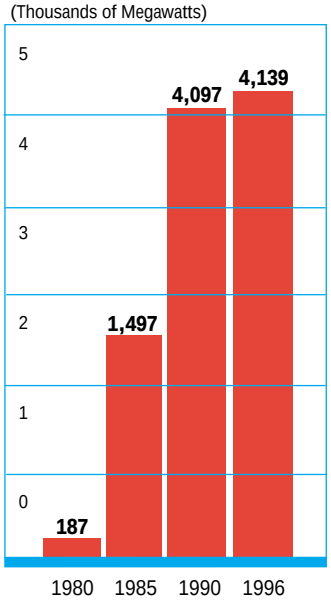
With the growth rate for non-hydro power renewable electricity generation more than doubling the expected growth in overall electricity capacity, these energy sources will play a more significant role in electricity markets in the next two decades. However, the extent to which these domes tic resources 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



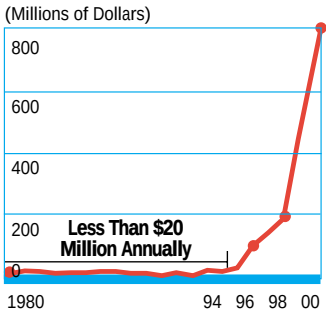
Source: U.S. Department of Energy, Energy Information Administration.



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
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.

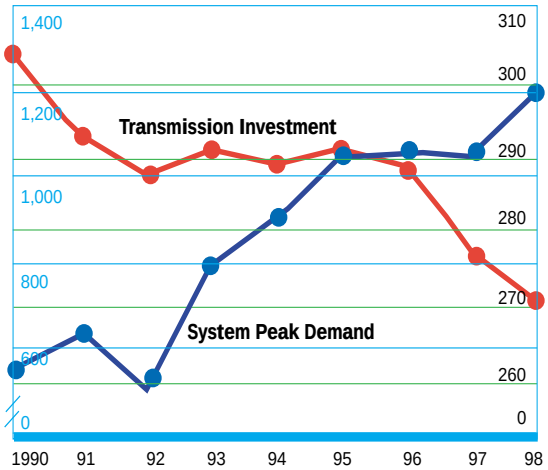
Another cause of transmission con straints is the siting process. Under current law, siting of transmission facilities is a re sponsibility of state governments, not the federal government, even though the trans mission system is not only interstate but also international, extending into both Canada 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:

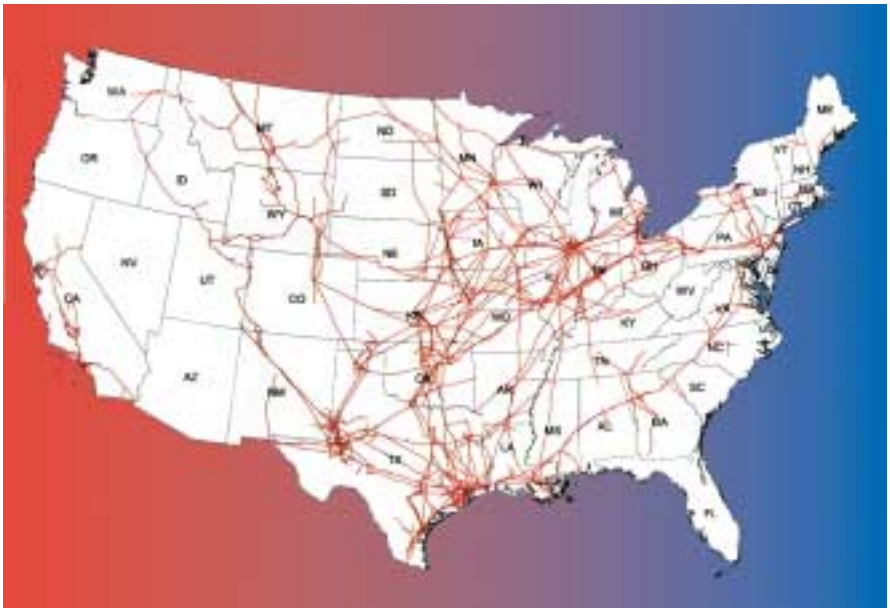
★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress and the State of Alaska to put in place the most expeditious process for renewal of the Trans-Alaskan Pipeline System rights-of-way to ensure that Alaskan oil continues to flow uninterrupted to the 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.

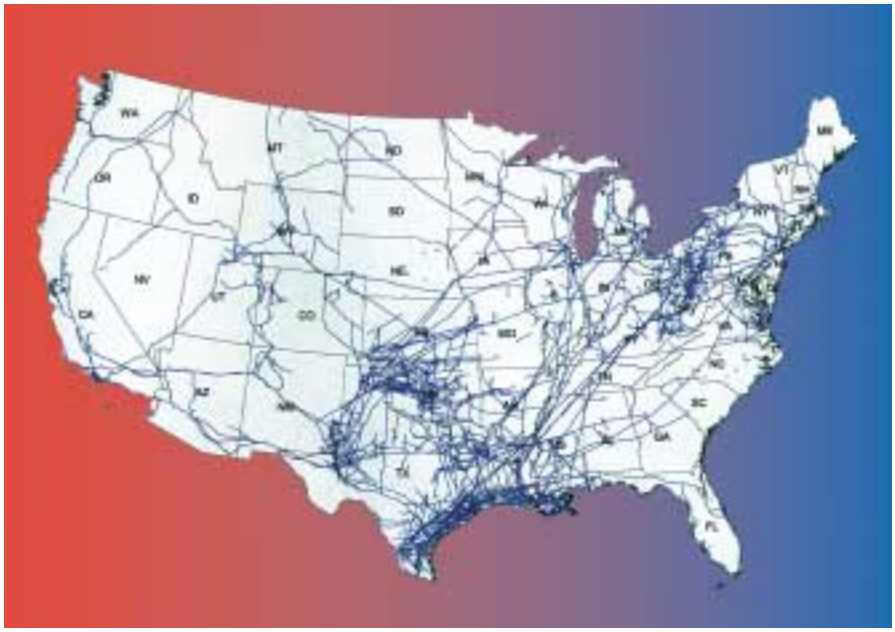
In addition to shortfalls in capacity, sources of natural gas have shifted from the Southwest to the deep water of the Gulf of Mexico, the Rocky Mountains, western Canada, and the Canadian Atlantic. At the same time, demand has shifted from the in dustrial Midwest to the growing population centers in 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.

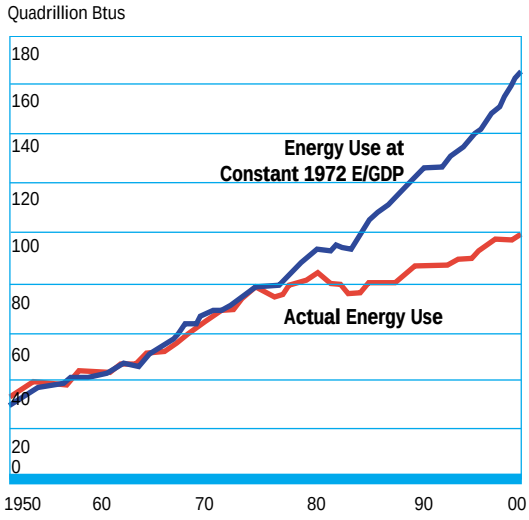
★ The NEPD Group supports the President's budget proposal to provide $8 million to maintain the two-million-barrel Northeast Heating Oil Reserve. Operated by the private sector, the Reserve helps ensure adequate supplies of heating oil in the event that colder than normal winters occur in the Northeast 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.

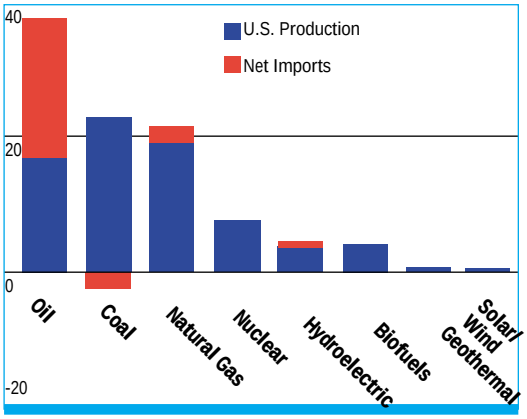
Measures to enhance U.S. energy security by meeting this increased demand must begin at home. The first step toward a sound international energy policy is to use our own capability to produce, process, and transport the energy resources we need in an efficient and environmentally sustainable manner. 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.

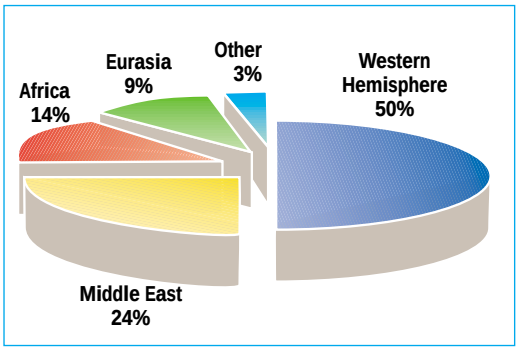
Our energy security also depends on an efficient domestic and international in frastructure to support all segments of the energy supply chain. We can strengthen our own energy security and the shared pros perity of the global economy by working cooperatively with key countries and insti tutions to expand 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.

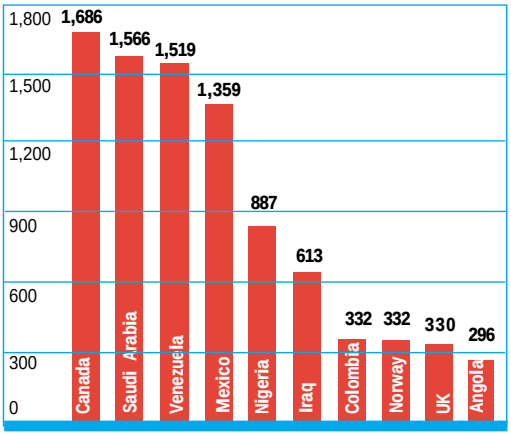
Source: US. Department of Energy, Energy Information Administration.

Recommendation:

★ The NEPD Group recommends- that the President make energy secu - rity 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 se curity of U.S. energy supply is enhanced by several factors characterizing our diplo matic and economic relationships with our four top suppliers. These factors range from geographic proximity and free trade agree ments to integrated pipeline networks, re ciprocal energy-sector investments, shared security commitments, and, in all cases, long-term reliable supply relationships (Fig ure 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%).

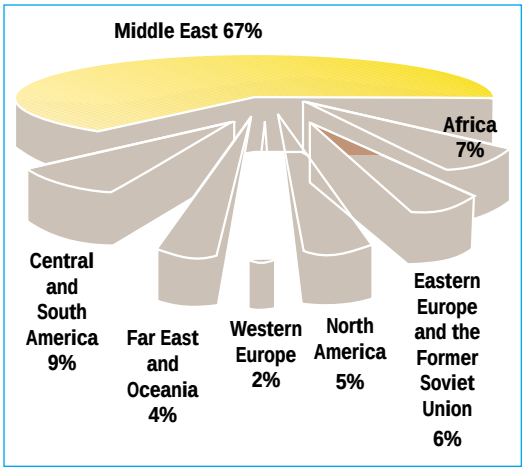
Source: U.S.Department of Energy, Energy Information Administration.-

Saudi Arabia and the Middle East Oil Supplies

By 2020, Gulf oil producers are pro jected 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 Petro leum Exporting Countries (OPEC) mem bers, 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 concen trated. 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 re gion (Figure 8-6). Algeria, Kuwait, Oman, Qatar, Saudi Arabia, the United Arab Emir ates (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 invest - ment. This development provides an impor - tant opportunity to further encourage for - eign investment in these important energy - producing countries, thereby broadening our shared commercial and strategic inter - ests. By any estimation, Middle East oil pro - ducers will remain central to world oil secu - rity. The Gulf will be a primary focus of U.S. international energy policy, but our engage ment 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 for - eign 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 pro duction and inventory levels has contrib uted to the price volatility witnessed in 2000. Discussions among the major oil pro ducers and consumer countries should be designed to improve the transparency, accu racy, 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 en ergy 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 pro - ducing 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 in vestments 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

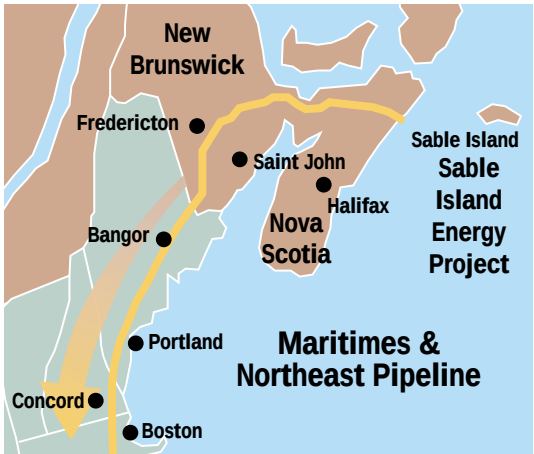


An integrated network of oil and gas pipelines demonstrates the seamless nature of North American energy trade.

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.

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



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.

★ 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.

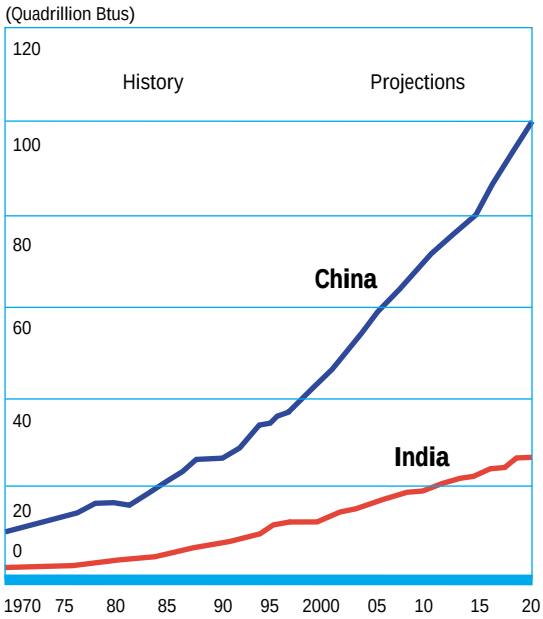
Asia

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.

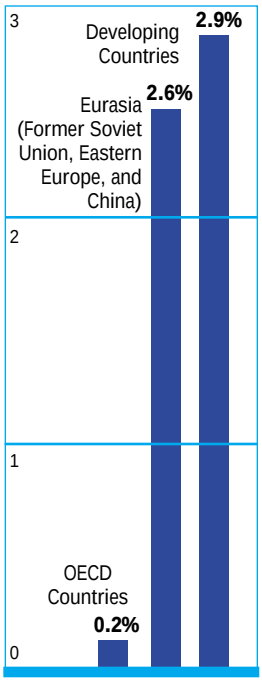
★ The NEPD Group recommends that the President promote a coordinated approach to energy security by calling for an annual meeting of G-8 Energy Ministers or their equivalents.

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

(Percent)

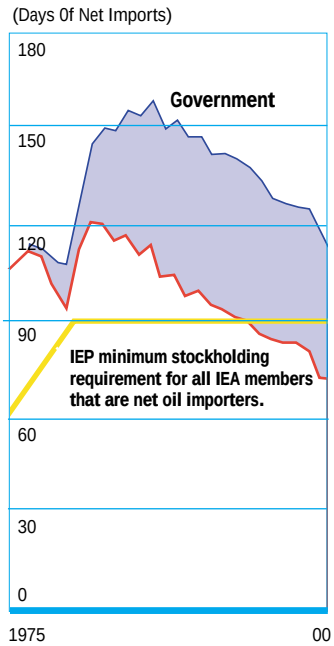


Over the next two decades, oil consumption in developing countries and Eurasia will grow three times faster than in the rest of the world.

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.

★ 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' 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.

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★ 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. *Not*e: 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: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	)

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

Exhibit 2-120:
Department Export Authorization EA-365-C (Oct. 21, 2025)

United States
Department of Energy

Grid Deployment Office

Research Power Corporation
(formerly known as Centre Lane Trading Ltd.)
GDO Docket No. EA-365-C

Order Authorizing Electricity Exports to Canada

Order No. EA-365-C

October 21, 2025

Research Power Corporation
(formerly known as Centre Lane Trading Ltd.)
Order No. EA-365-C
Authorizing Electricity Exports to Canada

I. BACKGROUND

The Department of Energy (DOE or Department) regulates electricity exports from the United States to a foreign country in accordance with Federal Power Act (FPA) § 202(e) (16 U.S.C. § 824a(e)) and regulations thereunder (10 C.F.R. §§ 205.300 *et seq.*). This authority was transferred to DOE under §§ 301(b) and 402(f) of the DOE Organization Act (42 U.S.C. §§ 7151(b) and 7172(f)). On April 10, 2023, this authority was delegated to the DOE's Grid Deployment Office (GDO) by Redelegation Order No. S3-DEL-GD1-2023.

An entity that seeks to export electricity must obtain an order from DOE authorizing it to do so. Under FPA § 202(e), DOE "shall issue such order upon application unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States or would impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of [DOE]." 16 U.S.C. § 824a(e). DOE has discretion to condition the order as necessary or appropriate; the Department "may by its order grant such application in whole or in part, with such modifications and upon such terms and conditions as [DOE] may find necessary or appropriate, and may from time to time, after opportunity for hearing and for good cause shown, make such supplemental orders in the premises as it may find necessary or appropriate." *Id*.

A. Application for Export Authorization

Research Power Corporation (the Applicant) is a power marketer seeking renewal of its authorization to export electric energy to Canada, which was originally granted in Order No. EA-365-A on June 29, 2015, and subsequently renewed (EA-365-B) on April 29, 2020. On December 26, 2024, Centre Lane filed an application with DOE (Application or App.) requesting renewal of its export authority for a five-year term. App. at 1. On July 7, 2025, the Applicant notified DOE of its corporate name change from Centre Lane Trading Ltd. to Research Power Corporation.

According to the Application, Research Power Corporation (formerly known as Centre Lane Trading Ltd.) "is a Canadian Corporation with its principal place of business in Toronto, Ontario" that is "organized under the *Business Corporations Act* of the Province of Ontario, Canada." *Id*. The Applicant states that it "does not own, operate or control any generation or transmission facilities in any region, nor is it affiliated with any entity that owns, operates or controls generation or transmission facilities, and is not affiliated with any franchised public utility." *Id* at 1-2. The applicant further represents that it is a "[Federal Energy Regulatory Commission]-authorized power marketer engaging in the purchase and sale of physical and/or

virtual energy in the Day-ahead and Real-time Markets of various Independent System Operators and Regional Transmission Organizations." App at 2.

Research Power Corporation represents that it "has no electric power supply system on which the proposed exports could have a reliability, fuel use system or stability impact." App. at 3. The Applicant states that it "has no obligation to serve native load usually associated with a franchised service area, and, thus, the exports proposed by [Research Power Corporation] will not impair its ability to meet current and prospective power supply obligations." *Id.* The Applicant further affirms that it "will purchase power to be exported from a variety of sources such as power marketers, independent power producers, or U.S. electric utilities and federal power marketing entities as those terms are defined in Sections 3(22) and 3(19) of the FPA" and that "such power is surplus to the system of the generator and, therefore, the electric power that [Research Power Corporation] will export on either a firm or interruptible basis will not impair the sufficiency of the electric power supply within the U.S." *Id*.

The applicant states that it "will make all necessary commercial arrangements and will obtain any and all other regulatory approvals required in order to schedule and deliver power exports." *Id*. The Applicant further states that it will "schedule its transactions with the appropriate balancing authority areas in compliance with the reliability criteria standards and guidelines established by the North American Electric Reliability Corporation[.]" *Id*. Research Power Corporation also attests to not exceed the export limits for the facilities, or otherwise cause a violation of the terms and conditions set forth in the export authorizations for each. App at 4.

B. Procedural History

On December 26, 2024, Centre Lane filed a renewal application with DOE for export authority for a five-year term. *Id* at 1. On June 16, 2025, DOE published notice of Centre Lane's Application in the Federal Register (90 Fed. Reg. 25252) and asked for any interested parties to submit comments on the Application by July 16, 2025. On July 7, 2025, DOE received notice of Centre Lane's corporate name change to Research Power Corporation.

C. Public Comments

No public comments were received.

II. DISCUSSION AND ANALYSIS

DOE is statutorily obligated under FPA § 202(e) to grant requests for export authorization unless the Department finds that the proposed export would negatively impact either: (i) the sufficiency of electric supply, or (ii) the coordination of the electric grid. Regarding the first exception criterion, DOE shall approve an electricity export application "unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States …." 16 U.S.C. § 824a(e). DOE has interpreted this criterion to mean that sufficient generating capacity and electric energy must exist such that the export could be made without compromising the energy needs of the exporting region, including

serving all load obligations in the region while maintaining appropriate reserve levels. *See, e.g.*, *BP Energy Co.*, Order No. EA-314, at 1-2 (Feb. 22, 2007), *renewed*, Order No. EA-314-A, at 2 (May 3, 2012), Order No. EA-314-B, at 2 (Feb. 28, 2017), *renewed,* Order No. EA-314-C, at 4 (Dec. 20, 2021).

Under the second exception criterion, DOE shall approve an electricity export application "unless, after opportunity for hearing, it finds that the proposed transmission would … impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of [DOE]." 16 U.S.C. § 824a(e). DOE has interpreted this criterion primarily as an issue of the operational reliability of the domestic electric transmission system. Accordingly, the export must not compromise transmission system security and reliability. *See, e.g.*, Order No. EA-314-C, at 4.

A. Research Power Corporation Will Not Impair the Sufficiency of the Electric Supply in the United States

Sufficiency of supply, the first exception criterion, addresses whether regional electricity needs are met in the current market. DOE has analyzed this issue from both an economic and a reliability perspective. The economic perspective concerns the supply available to wholesale market participants. The reliability perspective focuses on preventing problems that could result from inadequate supplies. Taken together, DOE examines whether existing electric supply is available via market mechanisms, and whether potential reliability issues linked to supply problems are mitigated by reliability enforcement mechanisms.

From an economic perspective, DOE finds that the wholesale energy markets are sufficiently robust to make supplies available to exporters and other market participants serving United States regions along the Canadian and Mexican borders. Following enactment of the Energy Policy Act of 1992, Pub. L. No. 102-486, which encouraged the Federal Energy Regulatory Commission (FERC) to foster competition in the wholesale energy markets through open access to transmission facilities, energy markets developed across the United States to provide opportunities for a more efficient availability of supply. Subsequently, the Energy Policy Act of 2005, Pub. L. No. 109-58, reaffirmed the Government's commitment to competition in wholesale energy markets as national policy. FERC has continued to encourage the expansion of wholesale energy markets through its orders to remove barriers[1] and to ensure that these markets are functioning properly.[2] As a result, market participants have access to traditional bilateral contracts, as well as organized electricity markets run by regional transmission organizations (RTOs) or independent system operators (ISOs). FERC oversees these interstate wholesale electricity markets across most of the lower 48 states. Absent an indication in the record that the geographic markets relevant to this export authorization analysis are flawed and result in

[1] *See, e.g.*, *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009).

[2] *See, e.g.*, *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008), *as amended*, 126 FERC ¶ 61,261, *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

uneconomic exports that jeopardize regional supply, DOE finds that the proposed transmission for export does not impair the sufficiency of electric supply within the United States.

From a reliability perspective,[3] DOE focuses on the prevention of cascading outages and other problems that could result from inadequate resources.[4] Reliability oversight is addressed by the authority granted to FERC through the Energy Policy Act of 2005. That Act added section 215 to the FPA, which directed FERC to certify an electric reliability organization and develop procedures for establishing, approving, and enforcing mandatory electric reliability standards. 16 U.S.C. § 824o. FERC certified the North American Electric Reliability Corporation (NERC) in 2006 to develop and enforce reliability standards for the bulk-power system in the United States. *Order Certifying NERC as the Electric Reliability Organization and Ordering Compliance Filing*, FERC Docket No. RR06-1-000, 116 FERC ¶ 61,062 (July 20, 2006). FERC approves these standards, at which point they become mandatory and enforceable. NERC Reliability Standards address areas such as resource and demand balancing, critical infrastructure protection, communications, emergency preparedness and operations, facilities design, transmission operations, transmission planning, modelling, nuclear, personnel performance and training, protection and controls, voltage and reactive, interchange scheduling and coordination, and interconnection reliability operations and coordination.

NERC Reliability Standards are enforceable throughout the continental United States, most of Canada south of the 60th parallel, and the Mexican state of Baja California Norte. Through enforcement by FERC, NERC, and six Regional Entities overseen by NERC,[5] all bulk-power system owners, operators, and users are held responsible for complying with reliability standards. The reliability standards are structured so that many entities have overlapping responsibility for the electric grid, thereby resulting in several layers of reliability monitoring. Entities such as reliability coordinators and balancing authorities coordinate power generation and transmission among multiple utilities to serve demand within an integrated regional wholesale market. One of the principal functions of these entities is to schedule adequate generating and reserve capacity. This allows them to serve demand at the regional level and to ensure that there is sufficient power supply to maintain system reliability. Reliability Standard IRO-001-4 "establish[es] the responsibility of Reliability Coordinators to act or direct other entities to act."[6] Requirement R1 states that "[e]ach Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions."[7] Reliability oversight is designed through coordinated efforts amongst Reliability Coordinators to preserve the benefits of interconnected operations and ensure that operations in one area will not adversely impact other areas.[8] Reliability Standard IRO-014-3 R1 provides that "[e]ach Reliability Coordinator shall have and implement Operating Procedures, Operating

[3] A related reliability analysis follows in the next section of this Order.

[4] This focus should not be confused with resource adequacy planning and capacity requirements that have traditionally been the domain of state regulatory commissions, NERC-certified Regional Entities, and RTOs/ISOs.

[5] The six entities are the Midwest Reliability Organization, Northeast Power Coordinating Council, ReliabilityFirst Corporation, SERC Reliability Corporation, Texas Reliability Entity, and Western Electricity Coordinating Council.

[6] Standard IRO-001-4 (Reliability Coordination – Responsibilities), at ¶ A.3.

[7] *Id.* ¶ B.R1.

[8] *See* Standard IRO-014-3 (Coordination Among Reliability Coordinators), at ¶ A.3.

Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability."[9]

DOE finds that NERC's FERC-approved comprehensive enforcement mechanism ensures that bulk-power system owners, operators, and users have a strong incentive both to maintain system resources and to prevent reliability problems that could result from movement of electric supplies through export. As a result of this reliability oversight, DOE finds that the sufficiency of supply is not impaired by Research Power Corporation's proposed export authorization.

DOE's sufficiency of supply findings are further supported by the fact that power marketers, such as Research Power Corporation, do not have an obligation to serve a franchised territory. Before the current role of power marketers emerged in the industry, the FPA § 202(e) inquiry into sufficiency of supply had a narrower focus and was designed for an applicant that was a vertically integrated utility[10] with an obligation to serve native load. Under that traditional scenario, the inquiry regarding sufficiency of supply logically sought to confirm that exports would be surplus to the needs of a vertically-integrated utility's native load obligations and reserve margins. As explained in DOE's notice of the first application by a power marketer for export authorization, the sufficiency of supply inquiry became unnecessary when applied to power marketers:

> The Applicant also is required to demonstrate that it would have sufficient generating capacity to sustain the proposed export under the terms and conditions of its export agreement, while still complying with any established reserve criteria.
>
> Since marketers generally could not be seen as having any "native load" requirements, the latter criterion of maintaining sufficient reserve margins appears inappropriate and unnecessary in this instance.

59 Fed. Reg. 54900 (Nov. 2, 1994). Power marketers do not have franchised service areas and, consequently, do not have native load obligations like a traditional local distribution utility that could be impaired by exports.

In sum, market mechanisms and reliability oversight protect against the possibility that Research Power Corporation's exports would jeopardize domestic sufficiency of supply. Therefore, an export by Research Power Corporation would not trigger the first exception criterion of FPA § 202(e) regarding the sufficiency of electric supply within the United States.

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[9] *Id.* ¶ B.R1.

[10] The Supreme Court of the United States has explained: "In 1935, when the FPA became law, most electricity was sold by vertically integrated utilities that had constructed their own power plants, transmission lines, and local delivery systems…[M]ost operated as separate, local monopolies subject to state or local regulation. Their sales were 'bundled,' meaning that consumers paid a single charge that included both the cost of the electric energy and the cost of its delivery. Competition among utilities was not prevalent." *New York v. FERC*, 535 US 1, 5 (2002).

B. Research Power Corporation's Requested Authorization Will Not Adversely Affect Either the Reliability or the Security of the United States Electric Transmission System

Reliability, the second exception criterion under FPA § 202(e), addresses operational reliability and security of the domestic electric transmission system. In evaluating the operational reliability impacts of export proposals, DOE has used a variety of methodologies and information, including established industry guidelines, operating procedures, and technical studies where available and appropriate. When determining these impacts, it is convenient to separate the export transaction into two parts: (i) moving the export from the source to a border system that owns the international transmission connection, and (ii) moving the export through that border system and across the border.

Moving Electricity to a Border System. Moving electricity for export to a border system necessarily involves the use of the bulk-power system. As noted in the preceding section, bulk-power system reliability concerns are addressed under the FPA by FERC and NERC and involve the enforcement of mandatory reliability standards. These standards ensure that all owners, operators, and users of the bulk-power system have an obligation to maintain system security and reliability. The standards are structured so that there are always entities with broader responsibilities than the applicant, such as reliability coordinators and balancing authorities, to keep a constant watch over the domestic transmission system.

To deliver the export from the source to a border system, the applicant must make the necessary commercial arrangements and obtain sufficient transmission capacity to wheel the exported energy to the border system. The applicant would be expected to follow FERC orders regarding open transmission access and to schedule delivery of the export with the appropriate RTO, ISO, and/or balancing authority (formerly the control area operator).

It is the responsibility of the RTO, ISO, and/or balancing authority to schedule the delivery of the export consistent with established and mandatory operational reliability criteria. During each step of the process of obtaining transmission service, the owners and/or operators of the transmission facilities will evaluate the impact on the system and schedule the movement of the export *only* if it would not violate established operating reliability standards. As a failsafe, the reliability coordinator in each region has the authority and responsibility to curtail, cancel, or deny scheduled flows to avoid shortages or to restore necessary energy and capacity reserves. Reliability Standard EOP-011-1 R2 provides that "[e]ach Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area."[11]

Specifically, the reliability coordinator has the authority to suspend exports if the electric energy would be needed to support the regional power grid. *See* Reliability Standard IRO-001-4 R1 ("Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions"), R2 ("Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the

[11] EOP-011-1 (Emergency Operations), at ¶ B.R2.

Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements"), and R3 ("Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator of its inability to perform the Operating Instruction issued by its Reliability Coordinator in Requirement R1").

DOE has determined that the existing industry procedures for obtaining transmission capacity on the domestic transmission system (described above) provide adequate assurance that any export will not cause an operational reliability problem. Therefore, Research Power Corporation's export authorization has been conditioned to ensure that the export will not cause operational issues on regional transmission systems to fall outside of established industry reliability criteria, or cause or exacerbate a transmission operating problem on the United States' electric power supply system (*see* Order below, Section VII, paragraphs C, D, and I).

Moving Electricity Through a Border System. The second part of DOE's reliability inquiry, addressing the transmission of the export through a border system and across the border, is a question of whether the border system is reliable and secure. To a large extent, this question is addressed by the jurisdiction of NERC. NERC and Regional Entities—including the Midwest Reliability Organization, the Northeast Power Coordinating Council, and the Western Electricity Coordinating Council—oversee the United States-Canadian border system and a significant part of the United States-Mexican border system. Those border systems are generally subject to the same reliability standards as domestic systems. *See, e.g.*, http://www.ieso.ca/sector-participants/system-reliability/reliability-standards-framework.

DOE also relies on the System Impact Studies submitted in conjunction with an application for a DOE-issued Presidential permit[12] to construct a new international transmission line. As DOE has previously reviewed System Impact Studies submitted with Presidential permit applications,[13] DOE does not need to perform additional impact assessments here, provided the maximum rate of transmission for all exports through a border system does not exceed the authorized limit of the system (*see* Order below, Section VII, paragraph (A)). In its application, Research Power Corporation committed to complying with all reliability limits on border facilities. *See* App. at 3. The second part of the reliability inquiry is therefore satisfied by DOE regulatory oversight, in addition to NERC's reliability enforcement.

III. FINDINGS AND DECISION

A. Research Power Corporation Meets the Statutory Requirements to Export Electric Energy to Canada

[12] DOE issues Presidential permits pursuant to Executive Order 10,485, as amended by Executive Order 12,038. *See* 10 C.F.R. §§ 205.320-205.329.

[13] *See, e.g.*, *AEP Tex. Cent. Co*., Order No. PP-317, at 2-3 (Jan. 22, 2007); *Mont. Alta. Tie Ltd.*, Order No. PP-305, at 2-4 (Nov. 17, 2008).

As explained above, DOE has assessed the impact that the proposed export would have on the reliability of the United States electric power supply system. DOE has determined that the export of electric energy to Canada by Research Power Corporation, as ordered below, would not impair the sufficiency of electric power supply within the United States and would not impede or tend to impede the coordination in the public interest of facilities within the meaning of FPA § 202(e).

B. Research Power Corporation Qualifies for a NEPA Categorical Exclusion for Exports of Electric Energy

Research Power Corporation's Application qualifies for DOE's categorical exclusion for exports of electric energy under the National Environmental Policy Act of 1969, as amended (NEPA), 42 U.S.C. § 4321 *et seq*. DOE's NEPA Implementing Procedures (June 2025) set forth this categorical exclusion, codified as "B4.2," as follows:

> Export of electric energy as provided by Section 202(e) of the Federal Power Act over existing transmission lines or using transmission system changes that are themselves categorically excluded.

10 C.F.R. Part 1021, App. B, § B4.2.

DOE has determined that actions in this category do not normally have a significant effect on the human environment and that, therefore, neither an environmental assessment nor an environmental impact statement normally is required. 10 C.F.R. § 1021.102(a).

To invoke this categorical exclusion, DOE must determine that, in relevant part, "[t]here are no extraordinary circumstances related to the proposal that may affect the significance of the environmental effects of the proposal." 10 C.F.R. § 1021.102(b)(2). "Extraordinary circumstances" include "unique situations" such as "scientific controversy about the environmental effects of the proposal; uncertain effects or effects involving unique or unknown risks; and unresolved conflicts concerning alternative uses of available resources." *Id*. DOE finds that granting Research Power Corporation's request for export authorization does not present such extraordinary circumstances. Research Power Corporation seeks to deliver electricity over existing international electric transmission facilities, which fits squarely within the B4.2 categorical exclusion. For these reasons, DOE will not require more detailed NEPA review in connection with this Application.

C. Conclusion

DOE grants Research Power Corporation's request for export authorization. Research Power Corporation is authorized to export electricity to Canada over any authorized international transmission facility that is appropriate for open access transmission by third parties, subject to the limitations and conditions described in this Order. The authorization shall be effective for a five (5) year term consistent with DOE's standard term for new electricity export authorizations.

IV. DATA COLLECTION AND REPORTING REQUIREMENTS

The responsibility for the data collection and reporting under orders authorizing electricity exports to a foreign country currently rests with the U.S. Energy Information Administration (EIA) within DOE. The Applicant is instructed to follow EIA instructions in completing this data exchange. Questions regarding the data collection and reporting requirements can be directed to EIA by email at EIA4USA@eia.gov or by phone at 1-855-342-4872.

Additionally, any change to the tariff of an entity with an export authorization must be provided to DOE's Grid Deployment Office via email at *electricity.exports@hq.doe.gov*. 10 C.F.R. § 205.308(b).

V. COMPLIANCE

Obtaining a valid order from DOE authorizing the export of electricity under FPA § 202(e) is a necessary condition before engaging in the export. Failure to obtain such an order or continuing to export after the expiration of such an order may result in a denial of authorization to export in the future and subject the exporter to sanctions and penalties under the FPA. DOE expects transmitting utilities owning border facilities and entities charged with the operational control of those border facilities, such as ISOs, RTOs, or balancing authorities, to verify that companies seeking to schedule an electricity export have the requisite authority from DOE to export such energy.

DOE expects Research Power Corporation to abide by the terms and conditions established for its authority to export electric energy to Canada, as set forth below. DOE intends to monitor Research Power Corporation compliance with these terms and conditions, including the requirement in paragraph G of this Order that Research Power Corporation create and preserve full and complete records and file reports with EIA as discussed above.

A violation of any of these terms and conditions, including the failure to submit timely and accurate reports, may result in the loss of authority to export electricity and subject Research Power Corporation to any applicable sanctions and penalties under the FPA.

VI. OPEN ACCESS POLICY

An export authorization issued under FPA § 202(e) does not impose a requirement on transmitting utilities to provide service. However, DOE expects transmitting utilities that own border facilities to provide open access transmission service across the border in accordance with the principles of comparable open access and non-discrimination contained in the FPA and articulated in FERC Order No. 888 (Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, FERC Statutes and Regulations ¶ 31,036 (1996)), as amended. The actual rates, terms, and conditions of transmission service should be consistent with the non-discrimination principles of the FPA and the transmitting utility's Open-Access Transmission Tariff on file with FERC.

All recipients of export authorizations, including owners of border facilities for which Presidential permits have been issued, are required by their export authorization to conduct operations in accordance with the applicable principles of the FPA and any pertinent rules, regulations, directives, policy statements, and orders adopted or issued thereunder, including the comparable open access provisions of FERC Order No. 888, as amended. Cross-border electric trade ought to be subject to the same principles of comparable open access and non-discrimination that apply to transmission in interstate commerce. *See Enron Power Mktg., Inc. v. El Paso Elec. Co.*, 77 FERC ¶ 61,013 (1996), *reh'g denied*, 83 FERC ¶ 61,213 (1998). Thus, DOE expects owners of border facilities to comply with the same principles of comparable open access and non-discrimination that apply to the domestic, interstate transmission of electricity.

VII. ORDER

Accordingly, pursuant to FPA § 202(e) and the Rules and Regulations issued thereunder (10 C.F.R. §§ 205.300-309), it is hereby ordered that Research Power Corporation is authorized to export electric energy to Canada under the following terms and conditions:

(A) The electric energy exported by Research Power Corporation pursuant to this Order may be delivered to Canada over any authorized international transmission facility that is appropriate for open access transmission by third parties in accordance with the export limits authorized by DOE.

(1) The following international transmission facilities located at the United States border with Canada are currently authorized by Presidential permit and available for open access transmission:[14, 15]

Owner	**Location**	**Voltage**	**Permit No.**[16]
Bangor Hydro-Electric Company	Baileyville, ME	345 kV	PP-89
Basin Electric Power Cooperative	Tioga, ND	230 kV	PP-64
Bonneville Power Administration (BPA)	Blaine, WA	2x 500 kV	PP-10
	Nelway, WA	230 kV	PP-36
	Nelway, WA	230 kV	PP-46
CHPE, LLC	Champlain, NY	±230 kV DC	PP-481[17]

[14] This Order authorizes the export of electricity over any "authorized international transmission facility," which is intended to include both large transmission lines and smaller distribution lines that have received a Presidential permit. However, the list in subparagraph (A)(1) of current facilities only includes transmission lines.

[15] The Applicant submitted a list identifying currently authorized transmission facilities (Attachment 1 of the Application). However, as information about some of those facilities may have changed since the Application was submitted, the table of transmission facilities in this Order may differ from the Applicant's submission to reflect those changes.

[16] These Presidential permit numbers refer to the generic DOE permit number and are intended to include any subsequent amendments to the permit authorizing the facility.

[17] Currently under construction and not yet operational as of September 2025.

Eastern Maine Electric Cooperative	Calais, ME	69 kV	PP-32
International Transmission Company	Detroit, MI	230 kV	PP-230
	Marysville, MI	230 kV	PP-230
	St. Claire, MI	230 kV	PP-230
	St. Claire, MI	345 kV	PP-230
Lake Erie Connector Transmission, LLC	Erie County, PA	320 kV	PP-412[18]
Long Sault, Inc.	Massena, NY	2x 115 kV	PP-24
Maine Electric Power Company	Houlton, ME	345 kV	PP-43
Minnesota Power, Inc.	International Falls, MN	115 kV	PP-78
Minnesota Power, Inc.	Roseau County, MN	500 kV	PP-398
Minnkota Power Cooperative	Roseau County, MN	230 kV	PP-61
Montana Alberta Tie Ltd.	Cut Bank, MT	230 kV	PP-399
NECEC Transmission LLC	Beattie Twp, ME	±320 kV	PP-438[19]
New York Power Authority	Massena, NY	765 kV	PP-56
	Massena, NY	2x 230 kV	PP-25
	Niagara Falls, NY	2x 345 kV	PP-74
	Devils Hole, NY	230 kV	PP-30
Niagara Mohawk Power Corp.	Devils Hole, NY	230 kV	PP-190
Northern States Power Company	Red River, ND	230 kV	PP-45
	Roseau County, MN	500 kV	PP-63
	Rugby, ND	230 kV	PP-231
Sea Breeze Olympic Converter LP	Port Angeles, WA	±450 kV DC	PP-299[20]
TDI New England	Alburgh, VT	±320 kV DC	PP-400[21]

[18] These transmission facilities have been authorized but not yet constructed or placed into operation.
[19] These transmission facilities have been authorized but not yet constructed or placed into operation.
[20] These transmission facilities have been authorized but not yet constructed or placed into operation.
[21] These transmission facilities have been authorized but not yet constructed or placed into operation.

Vermont Electric Power Co.	Derby Line, VT	120 kV	PP-66
Vermont Electric Transmission Co.	Norton, VT	±450 kV DC	PP-76
Vermont Transco LLC	Highgate, VT	120 kV	PP-82
Versant Power	Fort Fairfield, ME	69 kV	PP-497
	Madawaska, ME	138 kV	PP-498
	Easton, ME	7.2 kV	PP-499
	Baileyville, ME	345kV	PP-500

(2) The following are the authorized export limits for the international transmission lines listed above in subparagraph (A)(1):

(a) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on facilities authorized by Presidential Permit PP-64 (issued to Basin Electric Power Coop.) to exceed an instantaneous transmission rate of 150 megawatts (MW). The gross amount of energy that Research Power Corporation may export over the PP-64 facilities shall not exceed 900,000 megawatt-hours (MWH) during any consecutive 12-month period.

(b) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-32 (issued to Eastern Maine Electric Coop.) to exceed an instantaneous transmission rate of 15 MW. The gross amount of energy that Research Power Corporation may export over the PP-32 facilities shall not exceed 7,500 MWH annually.

(c) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-481-2 (issued to CHPE, LLC) to exceed an instantaneous transmission rate of 1,250 MW.

(d) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-230 (issued to International Transmission Company) to exceed a coincident, instantaneous transmission rate of 2.2 billion volt-amperes (2,200 MVA).

(e) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-412-1 (issued to Lake Erie Connector Transmission, LLC) to exceed an instantaneous transmission rate of 1,000 MW.

(f) Exports by Research Power Corporation made pursuant to this Order shall not cause the scheduled rate of transmission over a combination of facilities

authorized by Presidential Permits PP-43 (issued to Maine Electric Power Company) and PP-500 (issued to Bangor Hydro-Electric) to exceed 550 MW.

(g) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the combination of facilities authorized by Presidential Permits PP-497 and PP-498 (issued to Versant Power) to exceed a coincident, instantaneous transmission rate of 134 MW.

(h) Exports by Research Power Corporation made pursuant to this Order shall not cause total exports on the facilities authorized by Presidential Permit PP-78-1 (issued to Minnesota Power, Inc.) to exceed an instantaneous transmission rate of 100 MW. Exports by Research Power Corporation may cause total exports on the PP-78-1 facilities to exceed 100 MW only when total exports between the Mid-Continent Area Power Pool (MAPP) and Manitoba Hydro are below maximum transfer limits and/or whenever operating conditions within the MAPP system permit exports on the PP-78-1 facilities above the 100-MW level without violating established MAPP reliability criteria. However, under no circumstances shall exports by Research Power Corporation cause the total exports on the PP-78-1 facilities to exceed 150 MW.

(i) Exports made by Research Power Corporation pursuant to this Order shall not cause total exports on the facilities authorized by Presidential Permit PP-398 (issued to Minnesota Power, Inc.) to exceed an instantaneous transmission rate of 750 MW.

(j) Exports by Research Power Corporation made pursuant to this Order shall not cause total exports on a combination of the international transmission lines authorized by Presidential Permits PP-45 and PP-63 (issued to Northern States Power Company), PP-61 (issued to Minnkota Power), and PP-231 (issued to Northern States Power Company, d/b/a Excel Energy Inc. (Xcel)), to exceed an instantaneous transmission rate of 700 MW on a firm basis and 1,050 MW on a non-firm basis.

(k) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-66 (issued to Vermont Electric Power Co.) to exceed an instantaneous transmission rate of 50 MW. The gross amount of energy that Research Power Corporation may export over the PP-66 facilities shall not exceed 50,000 MWH annually.

(l) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-56 (issued to NYPA) to exceed an instantaneous transmission rate of 1,000 MW.

(m) Exports by Research Power Corporation made pursuant to this Order shall not cause: (a) the total exports on the facilities authorized by Presidential Permits PP-25, PP-30, PP-74 (issued to NYPA), and PP-190 (issued to Niagara Mohawk Power Corp.) to exceed a combined instantaneous transmission rate of 1,650

MW; and (b) the total exports on the 115-kV facilities authorized by Presidential Permit PP-24 (issued to Long Sault, Inc.) to exceed an instantaneous transmission rate of 100 MW. In addition, the gross amount of energy that Research Power Corporation may export over the PP-24 facilities shall not exceed 300,000 MWH annually.

(n) Exports by Research Power Corporation made pursuant to this Order shall not cause total exports on the two 500-kV lines authorized by Presidential Permit PP-10, the 230-kV line authorized by Presidential Permit PP-36, and the 230-kV line authorized by Presidential Permit PP-46 (issued to BPA) to exceed the following limits:

Condition	PP-36 & PP-46 Limit	PP-10 Limit	Total Export Limit
All lines in service	400 MW	1500 MW	1900 MW
1-500 kV line out	400 MW	300 MW	700 MW
2-500 kV lines out	400 MW	0 MW	400 MW
1-230 kV line out	400 MW	1500 MW	1900 MW
2-230 kV line out	0 MW	1500 MW	1500 MW

(o) Exports by Research Power Corporation made pursuant to this Order shall not cause a violation of the following conditions as they apply to exports over the facilities authorized by Presidential Permit PP-76-1, as amended (issued to the Vermont Electric Transmission Company):

Exports Through	NEPOOL Load Condition	Export Limit
Comerford converter	Summer, Heavy	650 MW
Comerford converter	Winter, Heavy	660 MW
Comerford converter	Summer, Light	690 MW
Comerford converter	Winter, Light	690 MW
Comerford & Sandy Pond converters	All	2,000 MW

(p) Exports by Research Power Corporation made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-399 (issued to Montana Alberta Tie Ltd.) shall not exceed an instantaneous transmission rate of 300 MW.

(q) Exports by Research Power Corporation made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-438 (issued to NECEC Transmission LLC) shall not exceed an instantaneous transmission rate of 1,200 MW.

(r) Exports by Research Power Corporation made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-299

(issued to Sea Breeze Olympic Converter LP) shall not exceed an instantaneous transmission rate of 550 MW.

(s) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-400 (issued to TDI-New England) to exceed an instantaneous transmission rate of 1,000 MW.

(t) Exports by Research Power Corporation made pursuant to this Order shall neither cause the total exports on the facilities authorized by Presidential Permit PP-82-6 (issued to Vermont Transco LLC) to exceed an instantaneous transmission rate of 250 MW.

(B) Changes by DOE to the export limits in other orders shall result in a concomitant change to the export limits contained in subparagraph (A)(2) of this Order. Changes to the export limits contained in subparagraphs (A)(2)(l), (m), and (n) will be made by DOE after submission of appropriate information demonstrating a change in the transmission transfer capability between the electric systems in New York State and Ontario and New York State and Quebec, and between BPA and BC Hydro or BPA and West Kootenay Power. Notice of these changes will be provided to Research Power Corporation.

(C) Research Power Corporation shall obtain any and all other Federal and state regulatory approvals required to execute any power exports to Canada. The scheduling and delivery of electricity exports to Canada shall comply with all reliability criteria, standards, and guidelines of NERC, reliability coordinators, Regional Entities, RTOs, ISOs or balancing authorities, or their successors, as appropriate, on such terms as expressed therein, and as such criteria, standards, and guidelines may be amended from time to time.

(D) Exports made pursuant to this authorization shall be conducted in accordance with the applicable provisions of the FPA and any pertinent rules, regulations, directives, policy statements, and orders adopted or issued thereunder, including the comparable open access provisions of FERC Order No. 888, as amended.

(E) The authorization herein granted may be modified from time to time or terminated by further order of DOE. In no event shall such authorization to export over a particular transmission facility identified in subparagraphs (A)(1) and (2) extend beyond the date of termination of the Presidential permit or treaty authorizing such facility.

(F) This authorization shall be without prejudice to the authority of any state or state regulatory commission for the exercise of any lawful authority vested in such state or state regulatory commission.

(G) Research Power Corporation shall make and preserve full and complete records with respect to the electric energy transactions between the United States and Canada. Research Power Corporation shall collect and submit the data to EIA as required by and in accordance with the procedures of Form EIA-111, "Quarterly Electricity Imports and Exports Report," and all successor forms.

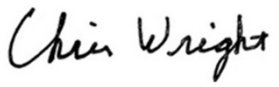
(H) In accordance with 10 C.F.R. § 205.305, this export authorization is not transferable or assignable, except in the event of involuntary transfer by operation of law. Provided written notice of the involuntary transfer is given to DOE within 30 days, this authorization shall remain in effect temporarily. The authorization shall terminate unless an application for a new export authorization has been received by DOE within 60 days of the involuntary transfer. Upon receipt by DOE of such an application, this existing authorization shall continue in effect pending a decision on the new application. In the event of a proposed voluntary transfer of this authority to export electricity, the transferee and the transferor shall file a joint application for a new export authorization, together with a statement of the reasons for the transfer.

(I) Nothing in this Order is intended to prevent the transmission system operator from being able to reduce or suspend the exports authorized herein, as necessary and appropriate, whenever a continuation of those exports would cause or exacerbate a transmission operating problem or would negatively impact the security or reliability of the transmission system.

(J) Research Power Corporation has a continuing obligation to give DOE written notification as soon as practicable of any prospective or actual changes of a substantive nature in the circumstances upon which this Order was based, including but not limited to changes in authorized entity contact information or NERC compliance registry status.

(K) This authorization shall be effective as of October 21, 2025 and shall remain in effect for a period of five (5) years from that date. Application for renewal of this authorization may be filed within six (6) months prior to its expiration. Failure to provide DOE with at least one hundred and twenty (120) days to process a renewal application and provide adequate opportunity for public comment may result in a gap in Research Power Corporation's authority to export electricity.

Issued in Washington, D.C., on October 21, 2025.



Chris Wright
Secretary of Energy
U.S. Department of Energy

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
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Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-121:
Mercury Mortality Risks of Coal

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Environment & Climate Health

Particulate pollution from coal associated with double the risk of mortality than PM2.5 from other sources

By **Staff Writer** • November 23, 2023

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For immediate release: November 23, 2023

Exposure to fine particulate air pollutants from coal-fired power plants (coal PM2.5) is associated with a risk of mortality more than double that of exposure to PM2.5 from other sources, according to a new study led by George Mason University, The University of Texas at Austin, and Harvard T.H. Chan School of Public Health. Examining Medicare and emissions data in the U.S. from 1999 to 2020, the researchers also found that 460,000 deaths were attributable to coal PM2.5 during the study period—most of them occurring between 1999 and 2007, when coal PM2.5 levels were highest.

The study was published on November 23, 2023, in Science.

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much more harmful than we thought, and its mortality burden has been seriously underestimated," said lead author Lucas Henneman, assistant professor in the Sid and Reva Dewberry Department of Civil, Environmental, and Infrastructure Engineering at Mason. "These findings can help policymakers and regulators identify cost-effective solutions for cleaning up the country's air, for example, by requiring emissions controls or encouraging utilities to use other energy sources, like renewables."

Using emissions data from 480 coal power plants in the U.S. between 1999 and 2020, the researchers modeled where wind carried coal sulfur dioxide throughout the week after it was emitted and how atmospheric processes converted the sulfur dioxide into PM2.5. This model produced annual coal PM2.5 exposure fields for each power plant. They then examined individual-level Medicare records from 1999 to 2016, representing the health statuses of Americans ages 65 and older and representing a total of more than 650 million person-years. By linking the exposure fields to the Medicare records, inclusive of where enrollees lived and when they died, the researchers were able to understand individuals' exposure to coal PM2.5 and calculate the impact it had on their health.

They found that across the U.S. in 1999, the average level of coal PM2.5 was 2.34 micrograms per cubic meter of air (µg/m3). This level decreased significantly by 2020, to 0.07 µg/m3. The researchers calculated that a one-µg/m3 increase in annual average coal PM2.5 was associated with a 1.12% increase in all-cause mortality among Medicare enrollees. Exposure to coal PM2.5 was responsible for 460,900 deaths

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The researchers were also able to quantify deaths attributable to specific power plants, producing a ranking of the coal-fired power plants studied based on their contribution to coal PM2.5's mortality burden. They found that 10 of these plants each contributed at least 5,000 deaths during the study period. They visualized the deaths from each power plant in a publicly available online tool (https://cpieatgt.github.io/cpie/).

The study also found that 390,000 of the 460,000 deaths attributable to coal-fired power plants took place between 1999 and 2007, averaging more than 43,000 deaths per year. After 2007, these deaths declined drastically, to an annual total of 1,600 by 2020.

"Beyond showing just how harmful coal pollution has been, we also show good news: Deaths from coal were highest in 1999 but by 2020 decreased by about 95%, as coal plants have installed scrubbers or shut down," Henneman said.

"I see this as a success story," added senior author Corwin Zigler, associate professor in the Department of Statistics and Data Sciences at UT Austin and founding member of the UT Center for Health & Environment Education & Research. "Coal power plants were this major burden that U.S. policies have already significantly reduced. But we haven't completely eliminated the burden — so this study provides us a better understanding of how health will continue to improve and lives will be saved if we move further toward a clean energy future."

The researchers pointed out the study's continuing urgency and relevance, writing in the paper that coal power is still part of some U.S. states' energy

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"As countries debate their energy sources—and as coal maintains a powerful, almost mythical status in American energy lore—our findings are highly valuable to policymakers and regulators as they weigh the need for cheap energy with the significant environmental and health costs," said co-author Francesca Dominici, Clarence James Gamble Professor of Biostatistics, Population, and Data Science at Harvard Chan School and director of the Harvard Data Science Initiative.

Funding for the study came from the National Institutes of Health (grants R01ES026217, R01MD012769, R01ES028033, 1R01ES030616, 1R01AG066793, 1RF1AG080948, and 1R01ES029950); the Environmental Protection Agency (grant 83587201); the EmPOWER Air Data Challenge (grant LRFH); the Alfred P. Sloan Foundation (grant G-2020-13946); and the Health Effects Institute (grants R-82811201 and 4953).

"Mortality risk from United States coal electricity generation," Lucas Henneman, Christine Choirat, Irene Dedoussi, Francesca Dominici, Jessica Roberts, Corwin Zigler, Science, online November 23, 2023, doi: 10.1126/science.adf4915.

Image: iStock/Tinton_Tree

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Harvard T.H. Chan School of Public Health brings together dedicated experts from many disciplines to educate new generations of global health leaders and produce powerful ideas that improve the lives and health of people everywhere. As a community of leading scientists, educators, and students, we work together to take innovative ideas from the laboratory to people's lives—not only making scientific breakthroughs, but also working to change individual behaviors, public policies, and health care practices. Each year, more than 400 faculty members at Harvard Chan School teach 1,000-plus full-time students from around the world and train thousands more through online and executive education courses. Founded in 1913 as the Harvard-MIT School of Health Officers, the School is recognized as America's oldest professional training program in public health.

George Mason University is Virginia's largest public research university. Located near Washington, D.C., Mason enrolled over 40,000 students from 130 countries and all 50 states for the fall 2023 semester. Mason has grown rapidly over the last half-century and is recognized for its innovation and entrepreneurship, remarkable diversity, and commitment to accessibility. Also in 2023, the university launched Mason Now: Power the Possible, a $1 billion comprehensive campaign to support student success, research, innovation, community, and sustainability. Learn more at gmu.edu .

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across 19 colleges and schools. As Texas' leading research university, UT attracts more than $650 million annually for discovery. Amid the backdrop of Austin, Texas, a city recognized for its creative and entrepreneurial spirit, the university provides a place to explore countless opportunities for tomorrow's artists, scientists, athletes, doctors, entrepreneurs and engineers.

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

Exhibit 2-122:
Energy Reliability and Resilience

The Wayback Machine - https://web.archive.org/web/20251021071021/https://www.energy.gov/eere/energy-reliability-and-resilience
An official website of the United States government Here's how you know

U.S. DEPARTMENT of ENERGY

Energy Reliability and Resilience



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Energy reliability is the ability of a power system to consistently deliver power to homes, buildings, and devices—even in the face of instability, uncontrolled events, cascading failures, or unanticipated loss of system components. Energy resilience is the ability of the grid, buildings, and communities to withstand and rapidly recover from power outages and continue operating with electricity, heating, cooling, ventilation, and other energy-dependent services. Energy resilience increases energy reliability and renewable energy sources can help support a resilient, reliable energy system.

Resilient, reliable energy is critical to the well-being of every American. It keeps life-saving hospital equipment and communications systems operating, buildings at safe temperatures with good ventilation, and American workers to go about their business without interruption. Energy infrastructure—facilities or equipment used to generate, deliver, process, or produce energy—that can withstand and quickly recover from disruptions is resilient and reliable infrastructure.

A resilient and reliable power system reduces the likelihood of long-duration outages over large service areas, limits the scope and impact of outages when they do occur, and rapidly restores power after an outage.

What Makes Energy Resilient?

Power outages can be caused by extreme weather, breaches in cybersecurity, high energy demand that overloads the electric grid, failure of aging equipment, and physical interference with equipment. Grid disturbances are changes in electrical voltage and frequency on the grid that can lead to power outages.

A resilient electric grid distribution system uses local resources, such as solar panels and battery storage in homes and buildings, to quickly reconfigure power flows and recover electricity services during a disturbance. The approach to modernize the grid and increase resilience focuses on integrating distributed energy resources, advanced controls, grid architecture, and emerging grid technologies at a regional scale.

Strong resilience measures in building energy codes can also ensure that new construction and major renovation projects minimize energy use, maximize comfort, and enhance potentially life-saving resilience benefits. Building owners and operators, communities, and local and state governments can strategically plan to increase resilience using these resources.

What Makes Energy Reliable?

When we diversify our energy mix by adding more types of energy to the grid, we increase our energy reliability. The rise of renewable power, which comes from unlimited energy resources, like wind, sunlight, water, and the Earth's natural heat, has the potential to vastly improve the reliability of the American energy system. Currently, renewable energy generates about 21% of all U.S. electricity, and that percentage is rising quickly.

A reliable electric grid distribution system can continue to deliver electricity to homes and buildings regardless of any disruptions or disturbances. The approach to modernizing the grid to increase resilience and reliability focuses on integrating distributed energy resources, advanced controls, grid architecture, and emerging grid technologies at a regional scale. DOE efforts, like the Energy Storage Grand Challenge Roadmap, will increase resilience. DOE's Grid Modernization Initiative works with public and private partners to develop concepts, tools, and technologies needed to measure, analyze, predict, protect, and control the grid of the future.

Improving Reliability Through Energy Storage

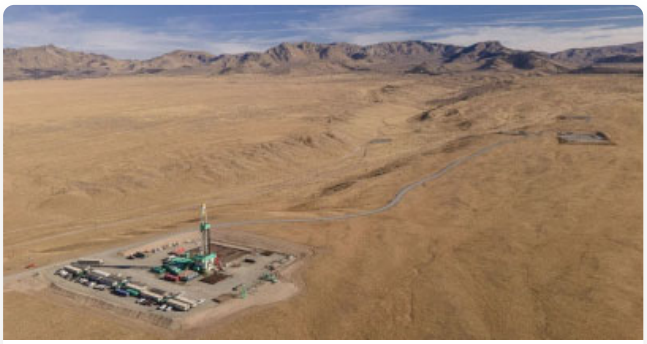
Energy storage technologies can improve energy reliability by making surplus energy available whenever it is needed, such as during a power outage.

Pumped storage hydropower is responsible for most U.S. commercial energy storage capacity and has been used for more than 100 years. Wind energy and solar energy can be captured and stored for later use with batteries, and researchers are investigating geothermal energy storage.

Energy storage is also essential to efficient transportation. EERE invests in research and development of hydrogen storage and batteries to ensure on- and off-road vehicles can reliably move people and goods from one place to another.

The U.S. Department of Energy's Energy Storage Grand Challenge is a comprehensive program to accelerate the development, commercialization, and use of next-generation energy storage technologies. As part of this program, the Long Duration Storage Shot™ aims to, within the decade, reduce the cost of grid-scale energy storage by 90% for systems that can provide energy for at least 10 hours in duration.

Energy Reliability and Resilience News



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PacifiCorp, and Xcel Energy	)

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

Exhibit 2-123:
EPA COBRA Health Effects Estimate

An official website of the United States government.

COBRA Web Edition



CO-Benefits Risk Assessment (COBRA) is a screening tool that enables state, local, and tribal government staff and others interested in the effects of air pollution to estimate the air quality and health benefits of different emissions scenarios.

You are using the web-based version of COBRA. For the COBRA desktop application, visit the COBRA download page.

Step 1: Build Scenario

Complete the sections below and click "Add to Scenario."

A. Select Location REQUIRED

Select the states or counties where the emissions changes will occur.

- [ ] Las Animas
- [ ] Lincoln
- [ ] Logan
- [ ] Mesa
- [ ] Mineral
- [x] Moffat
- [ ] Montezuma
- [ ] Montrose
- [ ] Morgan

Select All | Deselect All

B. Select Sector REQUIRED

Select the industry or sector where the emissions changes will occur.

Sector

Fuel Combustion: Electric Utility

Subsector (optional)

Coal

Subsector (optional)

All subsectors

C. Modify Emissions REQUIRED

Enter emissions changes for **at least one** of the four pollutants below.

$PM_{2.5}$ (Baseline = 93.48 tons)

reduce by | increase by

enter # (tons) (percent)

SO_2 (Baseline = 1,824.34 tons)

reduce by | increase by

enter # (tons) (percent)

NO_x (Baseline = 4,756.47 tons)

reduce by | increase by

enter # (tons) (percent)

VOC (Baseline = 114.8 tons)

reduce by | increase by

enter # (tons) (percent)

NH_3 (Baseline = 1.08 tons)

reduce by | increase by

enter # tons percent

ADD TO SCENARIO

Step 2: Review Scenario

Review the scenario below. To add changes to more locations or sectors, repeat Step 1 to continue building your scenario.

Location(s)	Sector	Emissions Modification(s)	
Moffat, Colorado	Fuel Combustion: Electric Utility Coal	$PM_{2.5}$ reduce by 13 tons SO_2 reduce by 335.43 tons NO_x reduce by 2,211.57 tons	✕

Discount rate:
2%
Custom: enter %

RUN SCENARIO

Step 3: View Results

BUILD NEW SCENARIO

A. Summary of Health Effects Results

Below is a table with the health effects results based on your scenario.

You are viewing results for all contiguous U.S. states. This is because changes in air quality can impact health endpoints in multiple locations due to the transportation of emissions across state and county lines.

Use the filters below to see health effects for a specific state or county.

1. Filter by state:

All contiguous U.S. states

2. Filter by county: (optional)

All counties

Results for: All Contiguous U.S. States

Export: All results | Current filter

Health Endpoint	Pollutant	Change in Incidence (cases, annual)		Monetary Value (dollars, annual)	
		Low	High	Low	High
Mortality *	$PM_{2.5}$ | O_3	3.4	4.4	$50,000,000	$64,000,000
Nonfatal Heart Attacks	$PM_{2.5}$	0.54	0.54	$46,000	$46,000
Infant Mortality	$PM_{2.5}$	0.0077	0.0077	$120,000	$120,000
Hospital Admits, All Respiratory	$PM_{2.5}$ | O_3	0.36	0.36	$7,300	$7,300
Emergency Room Visits, Respiratory	$PM_{2.5}$ | O_3	7.3	7.3	$12,000	$12,000
Asthma Onset	$PM_{2.5}$ | O_3	22	22	$1,700,000	$1,700,000
Asthma Symptoms	$PM_{2.5}$ | O_3	3,400	3,400	$1,100,000	$1,100,000
Emergency Room Visits, Asthma	O_3	0.036	0.036	$30	$30
Lung Cancer Incidence	$PM_{2.5}$	0.061	0.061	$2,700	$2,700
Hospital Admits, Cardio-Cerebro/Peripheral Vascular Disease	$PM_{2.5}$	0.1	0.1	$3,000	$3,000
Hospital Admits, Alzheimers Disease	$PM_{2.5}$	0.36	0.36	$8,200	$8,200

Hospital Admits, Parkinsons Disease	$PM_{2.5}$	0.052	0.052	$1,200	$1,200
Stroke Incidence	$PM_{2.5}$	0.053	0.053	$3,300	$3,300
Hay Fever/Rhinitis Incidence	$PM_{2.5}$ | O_3	140	140	$150,000	$150,000
Cardiac Arrest, Out of Hospital	$PM_{2.5}$	0.013	0.013	$780	$780
Emergency Room Visits, All Cardiac	$PM_{2.5}$	0.26	0.26	$550	$550
Minor Restricted Activity Days	$PM_{2.5}$	690	690	$87,000	$87,000
School Loss Days	O_3	1,800	1,800	$3,100,000	$3,100,000
Work Loss Days	$PM_{2.5}$	120	120	$37,000	$37,000
Total Health Effects from $PM_{2.5}$				**$12,000,000**	**$27,000,000**
Total Health Effects from O_3				**$44,000,000**	**$44,000,000**
Total Health Effects				**$56,000,000**	**$71,000,000**

Note: Dollar amounts shown are based on 2023 currency values. Additionally, all values have been rounded to 2 significant figures. Please export the results in order to see values prior to rounding.

* The Low and High values represent differences in the methods used to estimate some of the health impacts in COBRA. For example, high and low results for avoided premature mortality are based on two different epidemiological studies of the impacts of $PM_{2.5}$ on mortality in the United States.

B. Map of Health Effects and Air Quality Results

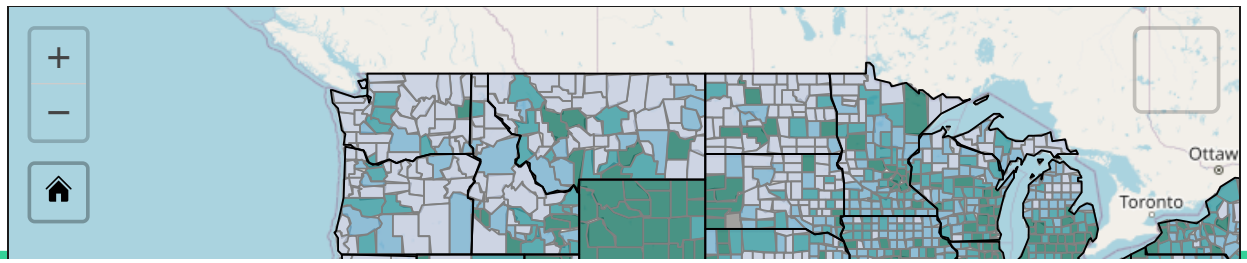
Below is a map showing health effects and air quality data based on your scenario.

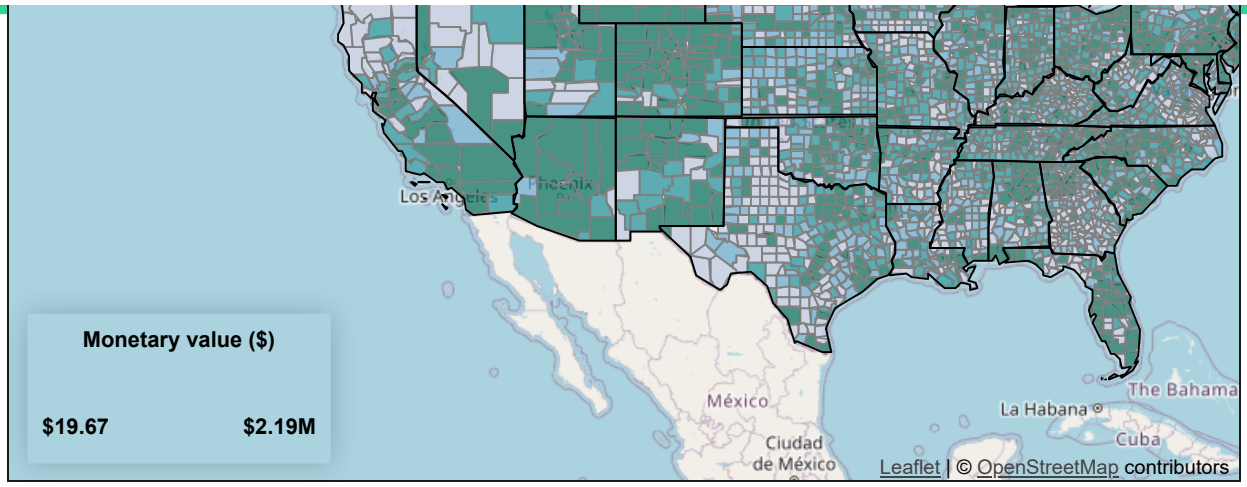
Use the filter below to change the map's data layer. Click on a county on the map to explore the data.

Select the map's data layer:

Total Health Benefits ($, low estimate)

Displaying: Total Health Benefits ($, low estimate)





LAST UPDATED ON APRIL 12, 2021

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

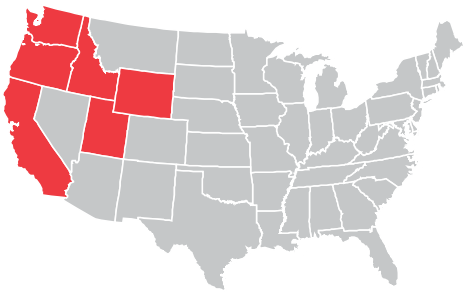
Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-124:
2025 PacifiCorp Fact Sheet

JUST THE **FACTS**

PacifiCorp

SERVICE AREA	141,500 square miles
ELECTRIC CUSTOMERS SERVED	2.1 million
NET OWNED GENERATION CAPACITY	11,700 megawatts
NET OWNED RENEWABLE AND NONCARBON CAPACITY	3,410 megawatts
RENEWABLE PROJECTS UNDER CONSTRUCTION, CAPACITY	531 megawatts
ELECTRIC TRANSMISSION LINE MILES	17,500 miles
ELECTRIC DISTRIBUTION LINE MILES	66,900 miles



- PacifiCorp owns and operates a diverse portfolio of generation resources in eight states comprised of coal, natural gas, hydroelectric, solar, geothermal and the largest owned wind fleet by a regulated utility in the Western U.S. The company also owns and operates the largest transmission system in the Western U.S., with 17,500 miles of transmission lines across 10 states. PacifiCorp serves customers through its two divisions:
  - Rocky Mountain Power is based in Salt Lake City, Utah, and serves customers in Utah, Wyoming and Idaho.
  - Pacific Power is based in Portland, Oregon, and serves customers in Oregon, Washington and California.
- PacifiCorp's Energy Gateway transmission expansion project is the largest of its kind in the U.S. The $13 billion investment totals 2,300 miles, provides access to the West's abundant and diverse energy resources, and is the foundation for a more resilient, reliable Western grid.
- As a founding partner in the Western Energy Imbalance Market in 2014, PacifiCorp has saved customers $938 million and significantly reduced emissions in the region. To further magnify the benefits of market collaboration, PacifiCorp plans to join the Extended Day-Ahead Market in 2026.
- Through investments of $1 billion through 2024 and another $2 billion planned through 2027, PacifiCorp continues to strengthen its system to reduce the risk of and prevent wildfires.
- PacifiCorp owns and manages 46,000 acres of lands reserved for wildlife habitat, forestry and recreation.







PACIFICORP®

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

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

Exhibit 2-125:
Service Area and Territory (Electric Power and Water) SRP

Service Territory

As a community-based not-for-profit water and energy company, SRP provides reliable, affordable water and power to more than 2 million people living in central Arizona.

Enter your address to see the SRP services available at your location

SRP delivers affordable water and power to more than 2 million customers living in and around the Valley. Our service territory is broad and covers much of central Arizona. Some addresses receive only one of our services while others are provided both water and power.

Feedback

Find address or place



Esri, TomTom, Garmin, FAO, NOAA, USGS, Bureau of Land Management, EPA, NPS, USFWS

Powered by Esri

Search for an address to learn more about the location and its surrounding area.

If you don't know the address, use one of these search methods:

Click the search box and type in an address or choose **Use current location.**

Be sure to click within the map.

Feedback

RELATED TOPICS



About Salt River Project | SRP

SRP is a community-based, not-for-profit organization providing affordable water and power to more than 2 million people in central Arizona. Read more here.



[History of Salt River Project | SRP]

Since 1903, Salt River Project has helped shape our state. Learn about our history of service to the people who call Arizona home.



[Future plan for energy | SRP]

Ensuring that the Valley's energy future remains reliable requires energy experts and communities working together. Learn about SRP's energy plan for the future.

Feedback

SUPPORT

Contact us

Residential electric: **(602) 236-8888**

Business electric: **(602) 236-8833**

SRP irrigation: **(602) 236-3333**

La Línea: **(602) 236-1111**

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PacifiCorp, and Xcel Energy	)

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

Exhibit 2-126:
Xcel, List of Towns Receiving Electric Service in Colorado

COLORADO COMMUNITIES SERVED BY XCEL ENERGY

INFORMATION SHEET
COLORADO

Xcel Energy®

= Gas only = Electricity only = Gas and Electricity

- Alamosa
- Alma
- Antonito
- Arvada
- Aspen Park
- Atwood
- Ault
- Aurora
- Avon
- Avondale

B

- Barnesville
- Battlement Mesa
- Beaver Creek
- Bellvue
- Bergen Park
- Berthoud
- Berthoud Falls
- Black Hawk
- Blanca
- Blue River
- Bonanza
- Boone
- Boulder
- Bountiful
- Bow Mar
- Bracewell
- Breckenridge
- Briggsdale
- Brighton
- Broomfield
- Brush

C

- Campion
- Canfield
- Canon
- Canyon Creek
- Capulin
- Carbondale
- Castle Pines
- Centennial
- Center
- Central City
- Chama
- Cherry Hills Village
- Clifton
- Climax
- Cody Park
- Columbine Valley
- Commerce City
- Conejos
- Conifer
- Copper Mountain
- Cornish
- Crisman

D

- De Beque
- Del Norte
- Denver
- Dillon
- Downieville
- Dumont

E

- Eastlake
- Eaton
- Edgewater
- Eldora
- Eldorado Springs
- Empire
- Englewood
- Erie
- Estes Park
- Evans
- Evergreen

F

- Fairplay
- Farmers Spur
- Federal Heights
- Fort Collins
- Fort Garland
- Fort Lupton
- Fort Morgan
- Fosston
- Foxfield
- Fraser
- Frisco
- Fruita
- Fruitvale

G

- Galeton
- Garden City
- Garfield
- Georgetown
- Gilcrest
- Gill
- Gilman
- Glendale
- Glenwood Springs
- Gold Hill
- Golden
- Granby
- Grand Junction
- Grand Lake
- Greeley
- Greenwood Village
- Guadalupe

H

- Hideaway Park
- Highlands Ranch
- Hillrose
- Homelake
- Hooper
- Horca
- Hot Sulphur Springs
- Hygiene

I

- Idaho Springs
- Idledale
- Indian Hills

J

- Jamestown
- Johnstown

K

- Kelim
- Kersey
- Keystone
- Kittredge
- Kremmling
- Kuner

COLORADO COMMUNITIES SERVED BY XCEL ENERGY

= Gas only = Electricity only = Gas and Electricity

- La Jara
- Laporte
- La Salle
- La Valley
- Lafayette
- Lakeside
- Lakewood
- Las Mesitas
- Lawson
- Leadville
- Leyden
- Littleton
- Lobatos
- Lochbuie
- Log Lane Village
- Lone Tree
- Longmont
- Lookout Mountain
- Louisville
- Louviers
- Loveland
- Lucerne
- Lyons

M

- Magnolia
- Malta
- Manassa
- Marshall
- Marshdale
- Maysville
- Mead
- Merino
- Milliken
- Minturn
- Moffat
- Mogote
- Monarch
- Monte Vista
- Montezuma
- Morrison
- Mosca
- Mountain View
- Mount Vernon

N

- Nederland
- New Castle
- Niwot
- North Avondale
- Northglenn
- Nunn

O

- Orchard Mesa
- Ortiz

P

- Paisaje
- Palisade
- Parachute
- Parker
- Parshall
- Peaceful Valley
- Peckham
- Peetz
- Pierce
- Platoro
- Platteville
- Poncha Springs
- Pueblo
- Purcell

R

- Raymer
- Raymond
- Red Cliff
- Redlands
- Richfield
- Rifle
- Riverside
- Romeo
- Rulison
- Russell Gulch

S

- Saguache
- Salida
- Salina
- San Antonio
- San Francisco
- San Luis
- San Pablo
- San Pedro
- Sanford
- Sargent
- Sedalia
- Severance
- Sheridan
- Silt
- Silver Plume
- Silverthorne
- Smeltertown
- Snyder
- Springdale
- Sprucedale
- Sterling
- Sterling Ranch
- Stoneham
- Stringtown
- Sugarloaf
- Summitville
- Sunshine
- Superior

T

- Tabernash
- Thornton
- Timnath
- Tiny Town

V

- Vail
- Valmont
- Vineland

W

- Wah Keeney Park
- Wallstreet
- Ward
- Watkins
- Weldona
- Wellington
- West Vail
- Westminster
- Wheat Ridge
- Wiggins
- Willard
- Windsor
- Winter Park

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

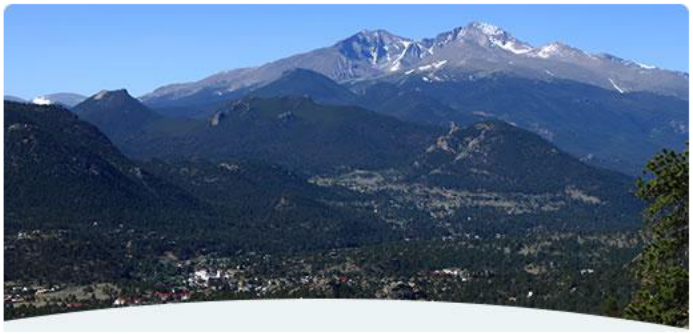
Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

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

Exhibit 2-127:
Who we serve - Platte River Power Authority

Our communities

Platte River Power Authority is a Colorado political subdivision established to provide wholesale electric generation and transmission to the utilities of its owner communities – Estes Park, Fort Collins, Longmont and Loveland.



Town of Estes Park

Estimated population*: 6,426
Utility: Estes Park Power and Communications, established in 1945
Source to Switch



City of Fort Collins

Estimated population*: 170,243
Utility: Fort Collins Utilities, established in 1938
Source to Switch



City of Longmont

Estimated population*: 97,261
Utility: Longmont Power & Communications, established in 1912
Source to Switch



City of Loveland

Estimated population*: 78,877
Utility: Loveland Water and Power, established in 1925
Source to Switch

*Based on the U.S. Census Bureau

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

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

Exhibit 2-128:
Order No. 24-073 OR PUC on Pac 2023 IRP

ORDER NO. 24-073

ENTERED Mar 19 2024

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 82

In the Matter of PACIFICORP, dba PACIFIC POWER, 2023 Integrated Resource Plan.	ORDER

DISPOSITION: STAFF'S RECOMMENDATION ADOPTED.

In this order, we adopt the recommendations made by Staff of the Oregon Public Utility Commission to acknowledge in part and not acknowledge in part PacifiCorp, dba Pacific Power's Integrated Resource Plan (IRP). We do not acknowledge PacifiCorp's Clean Energy Plan (CEP). We also adopt Staff's 21 recommendations, which set firm direction for what we require to be provided with PacifiCorp's 2025 IRP.

While we understand that development of PacifiCorp's 2025 IRP is a multi-stakeholder, multi-state process in which the company might reasonably seek our flexibility in setting requirements for the analysis, we are reacting to the rigidity PacifiCorp has displayed in responding to Oregon Staff and stakeholders' reasonable requests for adjustments and additional analysis during our review of its filed IRP and CEP, and even in its forthcoming IRP Update. We expect PacifiCorp to embrace the letter and spirit of the Staff recommendations that we adopt here, to follow them assiduously in developing its 2025 IRP, and to return to us for clarification if there is any doubt about what we require. With the urgency of reliability, cost control, and House Bill (HB) 2021 compliance challenges upon us, we would rather review any emerging questions or uncertainty about our direction before an IRP is locked down rather than find the IRP deficient and the company unwilling to adjust until the next cycle.

I. INTRODUCTION

The purpose of the IRP review process is to provide the utility with the input of the Commission, Commission Staff, and stakeholders on the reasonableness of the plan

presented. Our acknowledgment decision provides PacifiCorp with guidance to consider in taking resource actions that, ultimately, rest with the company.[1]

We take seriously our role in informing PacifiCorp's direction, but also reinforce that we do not control PacifiCorp's resource decisions and that any risks associated with carrying out even acknowledged actions rest with the company.

Our goal in an IRP proceeding is to acknowledge that a utility's action plan and preferred portfolio represent the least-cost, least-risk strategy for meeting customer needs, based on the best data available at the time and using the best available tools to analyze and review that data. In this particular IRP proceeding, we are asked to review a plan and portfolio that PacifiCorp had already abandoned by suspending the 2022 All-Source RFP, and that was further impacted by the stay of the federal Ozone Transport Rule. We are left without a plan that reflects PacifiCorp's reality, and without any willingness by PacifiCorp to adjust its action plan to reflect that reality. Therefore, we have no basis on which to acknowledge the majority of PacifiCorp's IRP, nor can we acknowledge its CEP without the foundation of a viable IRP action plan. We expect that, in 2025, we will be given a plan that follows Staff's recommendations and reflects both updated operating circumstances and an action plan that the company can stand behind. Recognizing that circumstances are rapidly evolving, that plan may describe action items and the key factors that would instigate a change in course. We also invite the company to present an IRP Update with revised actions that can serve as the foundation for a refiled CEP, which we will consider for acknowledgment and as a demonstration of continual progress.

II. IRP AND CEP PROCESS

A. Overall Purpose of the IRP

The IRP is a road map for providing reliable and least-cost, least-risk electric service to the utility's customers, consistent with state and federal energy policies, while addressing and planning for uncertainties.[2] The primary outcome of the process is the "selection of a

[1] *See In the Matter of the Investigation into Least-Cost Planning for Resource Acquisitions by Energy Utilities in Oregon*, Docket No. UM 180, Order No. 89-507 at 6 (Apr. 20, 1989) (explaining, "The Commission does not intend to usurp the role of utility decision-maker. Utility management will retain full responsibility for making decisions and for accepting the consequences of the decisions. Thus, the utilities will retain their autonomy while having the benefit of the information and opinion contributed by the public and the Commission* * *.").

[2] *In the Matter of Investigation into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-002 at Appendix A, Guidelines 1-13 (Jan. 8, 2007) corrected by Order No. 07-047 (Feb. 9, 2007); *In the Matter of Investigation into* the *Treatment of CO_2 Risk in the Integrated Resource Planning Process*, Docket No. UM 1302, Order No. 08-339 (June 30, 2008) (refining Guideline 8 addressing environmental costs.).

portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."[3]

Our IRP guidelines provide procedural and substantive requirements for utilities to meet in developing their IRPs.[4] Consistent with our guidelines, which require modeling of at least a 20-year time horizon, a utility's IRP must include the following key components:

- Identification of capacity and energy needs to bridge the gap between expected loads and resources;
- Identification and estimated costs of all supply-side and demand-side resource options;
- Construction of a representative set of resource portfolios;
- Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;
- Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers; and
- Creation of a two- to four-year Action Plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies.

In reviewing an IRP, we assess reasonableness based on the information available at the time. Our decision to acknowledge or not acknowledge an action item does not constitute ratemaking. Acknowledgment, or non-acknowledgment, of an IRP is a relevant but not exclusive consideration in our examination of whether the costs associated with a utility's resource investment should be recovered in customer rates. The question of whether a specific utility investment or procurement decision was prudent and reasonable will be examined in the subsequent rate proceeding.

B. Overall Purpose of the CEP

The Commission is tasked with ensuring progress towards, and evaluating compliance with, the emissions reductions targets required by HB 2021. Oregon electric companies subject to HB 2021 must file clean energy plans (CEPs), which we are charged with evaluating for acknowledgment pursuant to ORS 469A.415(6).[5] CEPs must meet statutory requirements set forth in ORS 469A.415, and also must demonstrate continual

[3] Order No. 07-002 at Appendix A, Guideline 1.
[4] Order No. 07-002 and Order No. 07-047 (adopting 13 IRP Guidelines); Order No. 08-339 (June 30, 2008) (refming Guideline 8 addressing environmental costs).
[5] ORS 469A.410(1) lists the required greenhouse gas emission reductions; the Commission's required evaluation is described in ORS 469A.415(4)(e) and (6).

progress towards meeting the HB 2021 targets in a way that results in "an affordable, reliable and clean electric system."[6]

Oregon electric companies subject to HB 2021's requirements must submit a CEP to the Commission concurrent with the development of each IRP.[7] CEPs "must be based on or included in an [IRP] filing," and must be filed concurrently with the IRP.[8]

Each CEP must:

(1) incorporate the clean energy targets articulated in ORS 469A.410;

(2) "[i]nclude annual goals set by the electric company for actions that make progress towards meeting the clean energy targets * * * including acquisition of nonemitting generation resources, energy efficiency measures and acquisition and use of demand response resources;"

(3) "[i]nclude a risk-based examination of resiliency opportunities that includes costs, consequences, outcomes and benefits based on reasonable and prudent industry resiliency standards;"

(4) "[e]xamine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy;"

(5) "[d]emonstrate the electric company is making continual progress within the planning period towards meeting the clean energy targets * * * including demonstrating a projected reduction of annual greenhouse gas emissions;" and

(6) "[r]esult in an affordable, reliable[,] and clean electric system."[9]

The actions and investments proposed in a CEP can include "the development or acquisition of clean energy resources, acquisition of energy efficiency and demand response * * * development of new transmission * * * retirement of existing generating facilities, changes in system operation and any other necessary action."[10]

The CEP must also "present annual goals for actions that balance expected costs and associated risks and uncertainties for the utility and its customers, including a demonstration of making continual progress towards meeting the clean energy targets, the

[6] ORS 469A.415(4)(f).
[7] ORS 469A.415(1).
[8] ORS 469A.415(3).
[9] ORS 469A.415(4)(a) - (f).
[10] ORS 469A.415(5).

pace of greenhouse gas emissions reductions, and community impacts and benefits."[11] The CEP must be "written in language that is as clear and simple as possible, with the goal that it may be understood by non-expert members of the public."[12]

III. PACIFICORP'S 2023 IRP AND CEP

After PacifiCorp filed its amended IRP and CEP in May 2023, we adopted a procedural schedule. This schedule allowed numerous opportunities for submission of written comments from Staff and intervenors, as well as opportunities to obtain feedback from PacifiCorp. On January 24, 2024, Staff filed its Round 2 Comments and Recommendations, in which it recommended truncating the schedule and bringing PacifiCorp's IRP to the February 20 regular public meeting for decision. Due to changed circumstances, including suspension of PacifiCorp's 2022 All-Source RFP and stay of the federal Ozone Transport Rule, Staff recommended only partial acknowledgment of the IRP and that instead of finishing the established procedural schedule, stakeholder and Staff attention should instead turn to the IRP update, to be filed in April 2024. On January 30, 2024, Staff filed a motion to modify the procedural schedule consistent with that recommendation, which was granted. After engagement with parties and Commissioner deliberation on February 20, we adopted the decision memorialized in this order at our March 5 regular public meeting.

C. PacifiCorp's Preferred Portfolio and Action Items

PacifiCorp states its preferred portfolio includes "substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources, advanced nuclear, and non-emitting peaking resources."[13] Among other things, PacifiCorp states that it plans 1,792 MW of wind, and 495 MW of solar additions with 200 MW of battery storage capacity from the 2020 All-Source RFP, as well as resource selections from the 2022 All-Source RFP. It also includes 1500 MW of advanced nuclear resources, including the 500 MW Natrium demonstration project. PacifiCorp asks for acknowledgment of the preferred portfolio, as well as a variety of actions, specifically:

- Existing Resource Actions – PacifiCorp seeks to exit Colstrip Units 3 and 4, and Craig Unit 1. It seeks to convert Naughton Units 1 and 2 and Jim Bridger Units 1 and 2 to gas. Finally, it seeks acknowledgment of its compliance plans for Wyoming House Bill 200 (Carbon Capture, Utilization, and Storage); regional haze; and the Ozone Transport Rule.

[11] OAR 860-027-0400(5).
[12] *Id.*
[13] Amended IRP at 10 (May 31, 2023).

- New Resource Actions – PacifiCorp seeks acknowledgment of its customer preference RFP; its 2024 All-Source RFP; and its 2022 All-Source RFP (now suspended).
- Transmission Action Items – PacifiCorp seeks acknowledgment for three long transmission segments – Energy Gateway South, Segment F; Energy Gateway West, Segment D.1; and Boardway-to-Hemingway – and for local reinforcement projects. It also seeks acknowledgment of continued permitting activities for Gateway West Segments D.3 and E.
- Demand-Side Management (DSM) Actions – PacifiCorp seeks acknowledgment of its energy efficiency targets.
- Market Purchases – PacifiCorp seeks acknowledgment of its intent to acquire short-term firm market purchases for on-peak delivery from 2023-2025.
- Renewable Energy Credit (REC) Actions – PacifiCorp seeks acknowledgment of its intent to pursue unbundled REC RFPs and purchases to meet state compliance obligations and to sell RECs that are not required to meet state RPS obligations.

D. PacifiCorp's CEP

PacifiCorp's CEP first discusses its community engagement strategy, community benefit indicators and metrics, local resiliency, and community-based renewable energy. It then discusses the company's procurement strategy and the IRP's projection that the company will need to acquire over 30 GWs of new resources, including over 800 MW of small-scale renewables. PacifiCorp's CEP finally lays out two pathways for complying with HB 2021: Pathway 1 achieves compliance by allocating the company's gas resources in such a way that the amount allocated to Oregon is capped; Pathway 2 achieves compliance by assuming that new large commercial load is 100 percent served with non-emitting generation through voluntary renewable options.

E. Stakeholder Engagement

Numerous stakeholders filed comments and otherwise participated in this proceeding. Some of their recommendations were incorporated by Staff into their initial and supplemental Staff Reports. Participating stakeholders were: the Oregon Citizens' Utility Board; Energy Advocates; Columbia River Inter-Tribal Fish Commission; NewSun Energy LLC; Renewable Northwest; Swan Lake North Hydro, LLC and FFP Project 101, LLC; Alliance of Western Energy Consumers; Fervo Energy; Sierra Club; Cascade Policy Institute; and Community Advocates.

F. Staff Report

On February 7, 2024, Staff submitted an extensive Staff Report, in which it reiterated its recommendation for partial acknowledgment. That Staff Report is attached as Appendix A. In it, Staff recommends acknowledging eleven action plan items and the company's load forecast. It recommends not acknowledging nine action plan items, the preferred portfolio, and the company's long-term IRP/CEP strategy. It also makes thirteen recommendations that it asks the Commission to adopt and lists over 50 expectations that it intends to work with the company on for the IRP Update or 2025 IRP; it states that it does not seek the Commission impose those expectations.

Staff recommends this course of action because "the 2023 IRP/CEP would not be revised to reflect major events—like the suspended acquisition of over 1 GW of renewable and storage capacity by 2027"—and therefore "Staff and stakeholders lack the shared analytic foundation from which most of the important acknowledgment decisions could be made."[14] Staff's recommendations are also premised on the fact that "the IRP Update will be filed in April 2024, presenting an opportunity to address these issues in a prompt and efficient manner."[15]

On March 1, 2024, Staff filed a report containing an updated set of recommendations, responding to Commissioner deliberation in the February 20 public meeting, including some edited recommendations and a number of new ones. This report is attached as Appendix B and stands as Staff's final recommendations in this proceeding. It did not change Staff's acknowledgment recommendations but did provide specific expectations for PacifiCorp's 2025 IRP and the analyses that PacifiCorp is to provide with that document.

IV. DISCUSSION

We adopt the recommendations set forth in Staff's March 1 report. We acknowledge certain elements and action items in the IRP, but do not acknowledge many other action items. Moreover, we do not acknowledge PacifiCorp's preferred portfolio or the CEP. The plans and many of the action items simply no longer reflect PacifiCorp's reality; most significantly, when PacifiCorp suspended the 2022 All-Source RFP and declined to update its analysis or the further procurement actions set forth in its action plan, we were left with few reality-based actions to acknowledge. Also, when the decision not to take those actions fundamentally undermines a preferred portfolio that was already substantially altered by the federal Ozone Transport Rule, we find it curious that PacifiCorp continues to assert that we should acknowledge its IRP and CEP. In short,

[14] Staff Report at 4.
[15] *Id.*

when the IRP and CEP are superseded by events, and the company makes no effort or space to adjust and provide visibility into what actions it is actually planning to take, acknowledgment is not appropriate. Much in the way we would not acknowledge actions that PacifiCorp has already taken, we do not see a point in acknowledging actions that PacifiCorp has already abandoned.

In saying this, we recognize that not all of these changed circumstances are in the company's control—there are real changes in federal regulations, real operating circumstances and pressures affecting the company, and some inflexibility in PacifiCorp's six-state IRP structure. Nonetheless, we expect PacifiCorp to design its IRP process so that Oregon-specific analysis is upfront and visible to us in our review. If IRP timelines in other states do not allow for testing assumptions and making adjustments during review of the filed IRP and CEP, we expect the company to make an extra effort to ensure a full exploration of alternatives for Oregon.

As to the CEP specifically, the elements that made up the basic actions that would move the company toward the HB 2021 targets were removed at the company's discretion and there has been no engagement around how those can be revised. PacifiCorp chose to pull back on the actions on which the CEP relied as the foundation for movement toward the clean energy targets—movement toward resource acquisitions that would reduce emissions but also, importantly, reduce customers' exposure to electricity market price volatility, for instance.

Beyond the changed circumstances, we are concerned that the CEP was treated as a manual or outboard adjustment to the preferred portfolio development and analysis in the IRP. Without alternative portfolio testing that incorporates state policy requirements, we are unable to see alternatives to the company's allocation-only approach. Had PacifiCorp's plans stayed on track, this approach may have been acceptable for a first iteration given PacifiCorp's persuasive assertion that the IRP preferred portfolio with reallocation was least cost for HB 2021 compliance, and we are not concluding that an allocation approach is legally invalid. It may well be a viable pathway, but going forward, we expect the company to integrate the requirements of state policies into the IRP itself. We need modeling of state policy in order to be able to see, among other things, achievement of the small-scale resource requirement in context of other resources and as a relative cost driver. As we understand it, a key element of HB 2021 is to be able to use the planning process to see tradeoffs and alternative paradigms, and we conclude that adopting requirements for 2025 is necessary to be able to understand PacifiCorp's alternatives for progress to HB 2021 compliance.

To that end, we are approving Staff's clear recommendations laying out a roadmap for the company's next IRP and we emphasize the importance of the company following

these recommendations in its 2025 IRP. At the same time, we invite the company to find a way to include in its 2024 IRP update some of the items that Staff is looking for and to update the CEP. We also voice our support for Staff continuing to pursue its non-binding "expectations;" it is not our intention to only support the items that have been formed into recommendations for our adoption.

We particularly want to call out Recommendations 15, 16, and 17 as difficult but important analyses. Stakeholders have worked with the company over successive IRP cycles to effectively model the comparative economics and flexibility of the many resource options, including careful analysis of when it is cost effective to retire a thermal facility. This rigor must continue as cost pressures mount. Recommendation 16, derived from CUB's comments, is a sound recommendation to incorporate actual carbon prices from California and Washington as PacifiCorp is modeling the cost of resources and the resulting dispatch. PacifiCorp has historically put a long-term price on carbon as a proxy for future regulatory requirements. HB 2021 requires a specific carbon budget and a carbon price, and without it, the CEP is not precise enough to establish compliance. Remedying this is especially important so that the CEP can test how much the portfolio as a whole will meet the Oregon requirements, how much will need to be solved with allocation, and what the cost will be. It will also help us determine whether the company is on a least-cost path to compliance. We also note that analysis of the federal loan program is a critical, near-term priority given capital constraints and rate pressure.

In general, we expect to see more cost information in the course of PacifiCorp's planning, both due to affordability concerns and because we need the company to be clearer about constraints that may be impacting their progress and how they are allocating their resources among their many priorities. The company should be transparent with stakeholders if the IRP Update or the 2025 IRP action plan are being driven by constraints that are not visible in the modeling The company needs to do more to communicating the many moving parts in the company's planning and procurement landscape.

We recognize that we committed in our order in docket UM 2273 to consider, alongside IRP and CEP review processes, whether utilities have demonstrated continual progress.[16] We are not doing so here simply because we expect, in a matter of weeks, to have a more realistic view of PacifiCorp's status with the IRP/CEP Update that are to be filed in April 2024. We will assess continual progress in connection with our review of the update. If we do not find that PacifiCorp has demonstrated "continual progress [toward the HB 2021 targets] and [that it] is taking actions as soon as practicable that facilitate

[16] *In the Matter of Public Utility Commission of Oregon, Investigation of House Bill 2021 Implementation Issues*, Docket No. UM 2273, Order No. 23-465 (Dec. 4, 203).

rapid reduction of greenhouse gas emissions at reasonable costs to retail electricity consumers," we will consider in a holistic manner whether we need to take actions to fulfill our responsibility to ensure this progress.

V. ORDER

IT IS ORDERED that the Integrated Resource Plan filed by PacifiCorp, dba Pacific Power, is acknowledged in part to the extent and with the conditions contained in Staff's February 7, 2024, and March 1, 2024 reports attached as Appendix A and Appendix B.

Made, entered, and effective Mar 19 2024.

Megan W. Decker
Chair

Letha Tawney
Commissioner

ITEM NO. RA4

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: FEBRUARY 20, 2024

REGULAR X CONSENT ____ EFFECTIVE DATE N/A

DATE: February 7, 2024

TO: Public Utility Commission

FROM: JP Batmale

THROUGH: Kim Herb **SIGNED**

SUBJECT: PACIFICORP:
Docket No. LC 82
Acknowledgement of 2023 Integrated Resource Plan and Clean Energy Plan.

STAFF RECOMMENDATION:

Acknowledge in part and not acknowledge in part PacifiCorp's (Company) 2023 Integrated Resource Plan (IRP), subject to the condition that the Company implements Staff's recommended conditions, including four recommended IRP analyses as part of the IRP Update. Decline to acknowledge the Clean Energy Plan (CEP) filed with the 2023 IRP. Direct the Company to revise and resubmit certain elements of the IRP, and to revise and resubmit the CEP, by the next IRP Update in April 2024, consistent with Staff's recommendations.

DISCUSSION:

Issue

Whether the Public Utility Commission of Oregon (PUC or Commission) should acknowledge PacifiCorp's IRP with or without conditions, acknowledge specific portions of the IRP, with or without conditions, or decline to acknowledge the IRP.

Whether the Commission should acknowledge PGE's CEP or decline to acknowledge the CEP and direct the Company to revise and resubmit certain portions of the plan. Whether the Commission should direct PGE to take any additional actions prior to filing its next IRP or IRP Update or CEP.

Applicable Law

The Commission adopted least-cost planning as the preferred approach to utility resource planning in 1989.[1] In 2007, the Commission updated its existing least-cost planning principles and established a comprehensive set of "IRP Guidelines" to govern the IRP process. The IRP Guidelines found in Order Nos. 07-002 (corrected by 07-047), and 08-339 clarify the procedural steps and substantive analysis required of Oregon's regulated utilities before the Commission considers acknowledgement of a utility's resource plan.[2] These orders are incorporated in OAR 860-027-0400(2), which requires any IRP to satisfy their requirements.

The IRP Guidelines and Commission rules require a utility to file an IRP with a planning horizon of at least 20 years within two years of its previous IRP acknowledgment order, or as otherwise directed by the Commission.[3] Further, the IRP must also include an "Action Plan" with resource activities that the utility intends to take over the next two to four years.[4] The utility's IRP should satisfy the IRP Guidelines and Commission rules for its determination of future long-term resource needs, its analysis of the expected costs and associated risks of the alternatives reviewed to meet its future resource needs, and its near-term Action Plan to achieve the IRP goal of selecting the "portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."[5] This is often referred to as the "least cost/least risk portfolio."

The Commission reviews the utility's plan for adherence to the procedural and substantive IRP Guidelines and generally acknowledges the overall plan if it is reasonably based on the information available at the time.[6] However, the Commission explains: "We may also decline to acknowledge specific action items if we question whether the utility's proposed resource decision presents the least cost and risk option for its customers."[7] The Commission may also provide direction on additional analysis or actions for the next IRP or IRP Update.[8]

[1] Order No. 89-507.
[2] Order Nos. 07-002 and 07-047. Additional refinements to the process have been adopted: See Order No. 08-339 (IRP Guideline 8 was later refined to specify how utilities should treat carbon dioxide (CO2) risk in their IRP analysis); Order No. 12-013 (guideline added directing utilities to evaluate their need and supply of flexible capacity in IRP filings).
[3] Order No. 07-002 (Guidelines 1(c) and 3(a)) and OAR 860-027-0400.
[4] Order No. 14-415 at 3.
[5] Order No. 07-002 at 1-2.
[6] *Id.* at 1.
[7] *Id.*
[8] OAR 860-027-0400(7), (10).

In 2021, the legislature passed Oregon House Bill (HB) 2021, codified as ORS 469A.400 to 469A.475, which requires the state's large investor-owned electric utilities (IOUs) and electricity service suppliers (ESSs) to decarbonize their retail electricity sales with consideration for direct benefits to local communities.

ORS 469A.415 requires large electric IOUs to, "develop a clean energy plan for meeting the clean energy targets set forth in ORS 469A.410 concurrent with the development of each integrated resource plan," and file the plan with the Commission and Oregon Department of Environmental Quality (DEQ).

ORS 469A.420 outlines the requirements and considerations for the Commission to acknowledge the CEP "…if the commission finds the plan to be in the public interest and consistent with the clean energy targets...."

In addition, ORS 469A.415(6) requires the Commission to ensure that the utilities demonstrate continual progress within the CEP planning period toward meeting the clean energy targets and are taking actions as soon as practicable to reduce emissions at reasonable cost to retail electricity consumers.

Additional requirements for the filing, review, and update of IRPs and CEPs are provided in OAR 860-027-0400.

Finally, PacifiCorp's previous IRP, LC 77, resulted in Order No. 22-178, which provided specific direction to the Company on analytic matters for this IRP.

Analysis

Background

PacifiCorp filed its 2023 Integrated Resource Plan and Clean Energy Plan (IRP/CEP or Plans) with PUC on May 31, 2023. PacifiCorp's filing shortly followed PGE's filing of the first IRP/CEP on March 31, 2023, both of which followed from the passage of HB 2021 and direction from Docket UM 2225.

Originally three rounds of comments had been planned in the lead up to a final Staff memo for an April 2024 Special Public Meeting to acknowledge PacifiCorp's 2023 IRP/CEP. Round 0 comments provided preliminary notes about improvements PacifiCorp could make in advance of participants' in-depth review of the IRP/CEP. Round 1 comments evaluated the reasonableness of the plan and explored acknowledgement considerations. Round 2 comments were meant to focus on Staff's draft recommendations for Commission acknowledgement of the IRP/CEP. The Company would respond with a final set of comments, typically including a final set of

revisions to the IRP. Then in March a public meeting memo from Staff with final acknowledgement recommendations was to be published, giving stakeholders and the Company a final opportunity to make written comments to the Commission.

Round 1 comments by Staff and stakeholders reflected the fact that there had been material changes impacting the IRP/CEP analysis since the documents were filed in May 2023. These changes rendered moot most of the IRP's Action Plan and Preferred Portfolio. The changes also undermined PacifiCorp's CEP and plan to meet the HB 2021 targets. Of particular concern, PacifiCorp confirmed in response to an information request that the Company will not be able to procure the clean energy additions included in the Preferred Portfolio through 2028 given the suspension of the 2022 All-Source RFP.[9]

In PacifiCorp's December 2023 LC 82 Round 1 reply comments, PacifiCorp made it plain that changes would not be made to the 2023 IRP/CEP, despite Staff and stakeholders' requests. Instead, the Company pointed toward the IRP Update – planned for April 2024 – for any revisions of the Company's now obsolete IRP analysis. PacifiCorp reinforced this position several information request responses.

As the 2023 IRP/CEP would not be revised to reflect major events – like the suspended acquisition of over 1 GW of renewable and storage capacity by 2027 – Staff and stakeholders lacked the shared analytic foundation from which most of the important acknowledgement determinations could be made. Given this threshold issue, Staff saw little value in continuing multiple rounds of comments on the plan as filed. Staff's Round 2 comments included proposed ***final*** recommendations, rather than ***draft*** recommendations, and a request to shorten the procedural schedule and end LC 82 in February, rather than April.[10] A revised schedule consistent with Staff's request was adopted by the ALJ in a ruling on February 5, 2024.

Staff sees benefits to an abbreviated schedule, and non-acknowledgment as proposed by Staff followed by revision and resubmission of the CEP and additional actions for the IRP Update. The first, the Company's planned IRP Update will be filed in April 2024, presenting an opportunity to address these issues in a prompt and efficient manner. Second, by directing a revised and resubmitted CEP in mid-2024, the Commission can avoid an extensive delay in the acknowledgment of a CEP the Company to implement, given the looming emissions reductions targets in HB 2021, rather than stalling consideration of the CEP to 2025. Finally, the Commission could consider providing

[9] PacifiCorp response to OPUC Staff Information Request No. 243.
[10] LC 82, OPUC Staff Second Round Comments, January 24, 2024, pg. 4 and Staff procedural motion on January 30, 2024 to change the schedule.

direction to shape PacifiCorp's quickly moving small-scale renewable request for proposal (SSR RFP).
Staff's redacted Round 2 comments are included with this memo as Attachment A. The Round 2 comments provide more details to Staff's recommendations. The Round 2 comments also include more background information on the IRP itself and stakeholder comments than is contained in this memo. This public meeting memo includes no new analyses. It does, however, seek to reemphasize and clarify the positions taken by Staff in the Round 2 comments and address potential shortcomings in the SSR RFP currently under development.

Acknowledgement Recommendations for the IRP and CEP
Staff made thirteen acknowledgement recommendations in our Round 2 comments.[11] They spanned the IRP and CEP. Staff also listed over fifty expectations for the IRP Update or the 2025 IRP. These expectations amounted to issues that did not require Commissioner deliberation and would not require an order. Instead, Staff plans to work with PacifiCorp and stakeholders to meet these expectations.
The table below summarizes the recommendations from Staff's comments regarding the IRP.[12]

Table 1

	Acknowledge	Not Acknowledge
IRP	• Eleven Action Plan Items (1a, 1b, 1e, 1f, 3a-3c, 3e, 4a, 6a, 6b) • Load Forecast	• Nine Action Plan Items (1c, 1d, 1g, 1h, 2a – 2c, 3d, 5a) • Preferred Portfolio • Long-Term IRP/CEP Strategy

With regard to the CEP, Staff believes that the necessary changes to the Preferred Portfolio in the IRP Update will significantly impact PacifiCorp's Oregon-allocated GHG emissions and/or the allocation strategies needed for PacifiCorp to comply with HB 2021. Staff does not believe the CEP is consistent with the emissions reduction targets of HB 2021, given the present circumstances. Staff therefore recommends that PacifiCorp be directed to revise and resubmit the CEP so that the emission strategy and information on costs to Oregon ratepayers is consistent with the information in the IRP Update.
With regard to PacifiCorp's allocation approach to CEP compliance pathways, Staff stated previously that we find the approach of testing hypothetical allocations to be a reasonable approach to forecasting future Oregon-allocated emissions in years beyond

[11] LC 82, OPUC Staff Second Round Comments, January 24, 2024, Appendix A, pgs. 55-56.
[12] *Id.*, pg. 4.

the current allocation agreement. It would, however, generate more insight if PacifiCorp tested more options and was more transparent about those options and their tradeoffs. Additionally, Staff is clear in our Round 2 comments that the Company is not expected to make significant revisions in community-focused areas of the CEP as part of a revised filing; only the CEP Compliance pathways and demonstration of continual progress on emission reductions. With that said, Staff did include four CEP, community-focused recommendations:

> **Staff Recommendation 5.** Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.
>
> **Staff Recommendation 6.** Direct PacifiCorp to provide baseline metrics prior to filing its next IRP/CEP Update. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable.
>
> **Staff Recommendation 7.** Direct PacifiCorp to proceed with the CBRE Grant Pilot, contingent on the Company seeking feedback from the CBIAG in Q1 2024.
>
> **Staff Recommendation 8.** Direct PacifiCorp to work collaboratively with Staff, stakeholders, peer utilities, and the CBIAGs in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs by December 31, 2024. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable, inclusive of the perspectives of peer utilities and the utilities' CBIAGs.

Beyond these recommendations, to the extent that the CEP's community-based activities or strategies have changed since it was filed in May 2023, the Company should provide new information in the revised CEP filing. Otherwise, Staff expects PacifiCorp to leverage the CBIAG and 2025 IRP process to continue to improve the community-based elements of the CEP.

Minimum Changes Sought by Staff in the IRP Update and Revised CEP
Staff's Round 2 comments identified four analytic threshold issues that would need to be addressed in the IRP Update and reflected in the revised and resubmitted CEP for

Staff to consider recommending acknowledgment of the revised and resubmitted CEP.[13] These were in addition to the thirteen acknowledgement recommendations.

1. Align the updated Preferred Portfolio and Action Plan with PacifiCorp's updated plans in light of key developments since the filing of the IRP, including the suspension of the 2022 AS RFP and the stay of the Ozone Transport Rule.
2. Include Oregon's Small Scale Renewable requirement in the updated Preferred Portfolio.
3. Confirm that the updated Preferred Portfolio can support simultaneous compliance with the clean energy requirements and GHG targets in Oregon, Washington, and California.
4. Fix any confirmed analytical errors identified in this docket, including any errors in the calculation or application of granularity adjustments.

On January 31, 2024, PacifiCorp released a draft of the IRP Update. This draft outlined eight areas that PacifiCorp planned to revise with new information in the IRP Update. They are:

- System coincident peak load forecast,
- Natural gas and power market price updates,
- Stay of the ozone transport rule,
- Suspension of the 2022 all-source RFP,
- Natural gas generation and the use of either green hydrogen or green ammonia,
- Preference for peaking type resources,
- Demand-side management,
- Front office transactions,
- Contracted resources, and
- Transmission option updates.

It appears that PacifiCorp plans to update the Preferred Portfolio and Action Plan in the IRP Update, though these updates were not completed and included in the draft document. PacifiCorp makes no mention of Staff's other three recommendations. Further, the draft IRP Update outline included no mention of seeking acknowledgement of a revised Preferred Portfolio and Action Plan as part of the IRP Update. All of these things are crucial.

If Staff's additional analyses are not addressed as part of the April 2024 IRP Update, Staff is concerned that the basis from which to assess the acknowledgability of a revised and resubmitted CEP will be compromised and more time wasted. Thus, Staff

[13] *Id.,* pg. 3.

requests that the Commission order PacifiCorp to conduct Staff's recommended analyses within the IRP Update, in addition to all thirteen recommendations from Staff's Round 2 comments.

Timing of Resubmission of Revised CEP
Due to the circumstances surrounding this IRP and CEP, Staff finds that PacifiCorp should seek to resubmit its revised CEP with the IRP update. However, given that April is less than two months away, Staff is open to PacifiCorp filing a request in its reply comments for an extended CEP filing date of four to eight weeks.[14] Regardless of the timing, Staff plans to work quickly to review the CEP once it is filed.

SSR RFP
The 2023 IRP/CEP forecasted a need of approximately 490 MW of new, renewable capacity – all less than 20 MW in size – to meet HB 2021's 2030 SSR requirement. Because the Company believes acquiring this volume and type of capacity by 2030 may be difficult, PacifiCorp plans to move rapidly. On January 24, 2024, PacifiCorp held a bidders workshop for its SSR RFP. The workshop outlined the Company's initial approach to acquiring the SSR resources necessary to meet a key component of HB 2021. Per the bidders conference presentation, the RFP will be finalized and issued by March 29, 2024. Staff appreciates the Company's sense of urgency on this topic.

However, Staff is concerned about the strategic choices made by PacifiCorp in designing this RFP. First, the timing was such that the bidders conference was the same day as Staff's comments were due. Staff did include two SSR RFP recommendations that were not part of the RFP. They were:

> **Staff Recommendation 5.** Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.
>
> **Staff Recommendation 9.** The SSR RFP incorporates into project selection criteria appropriate elements of the current Resiliency Analysis Framework and the CBRE Pilot be designed to promote resiliency-related factors.

Should the Commission choose to accept Staff recommendation we would hope to see the SSR RFP be updated accordingly.

[14] OAR 860-027-0400(9)(c).

Beyond this, the Company also appears to be establishing RFP parameters that limits the pool of potential resources, drives up SSR project costs borne by Oregon ratepayers, and/or limits insights into the community benefits of projects. Specifically:

- The RFP bars energy storage from being paired with eligible renewable systems.
- No RFP mechanism like non-price scoring or sensitivities to identify, track, and/or allow for project selection that accounts for community benefits.
- Premium peak hour pricing, like what was approved for Oregon PURPA projects, is not allowed. Only flat pricing and on-peak/off-peak.
- Requiring ODOE RPS certification, which includes WREGIS certification and metering.
- Requiring CAISO EIM visibility and dispatchability.

Staff has included two attachments associated with the SSR RFP. Attachment B is the bidders conference presentation and Attachment C Staff's response.

Time permitting at the Public Meeting, Staff suggests that it may be productive to discuss with PacifiCorp their SSR acquisition strategy. The SSR RFP represents one of the first actions by PacifiCorp to meet the HB 2021 targets. As such, a better understanding of PacifiCorp's strategy and approach to SSR acquisition could help all parties learn more about balancing tradeoffs around the economic and technical feasibility of HB 2021 actions.

PROPOSED COMMISSION MOTION:

Acknowledge in part and not acknowledge in part PacifiCorp's (Company) 2023 Integrated Resource Plan (IRP), subject to the condition that the Company implements Staff's recommended conditions, including four recommended IRP analyses as part of the IRP Update. Decline to acknowledge the Clean Energy Plan (CEP) filed with the 2023 IRP. Direct the Company to revise and resubmit certain elements of the IRP, and to revise and resubmit the CEP, by the next IRP Update in April 2024, consistent with Staff's recommendations.

LC 82

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

Docket No. LC 82

In the Matter of PACIFICORP, dba PACIFIC POWER, 2023 Integrated Resource Plan.	OPUC STAFF ROUND 2 COMMENTS AND RECOMMENDATIONS

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Executive Summary

In this second round of comments on the PacifiCorp (PAC or Company) Integrated Resource Plan (IRP) and Clean Energy Plan (CEP), the Oregon Public Utilities Commission (OPUC) Staff puts forth draft recommendations for acknowledgment and future expectations. Our recommendations and expectations cover this IRP, the planned IRP Update (April 2024), and the next IRP (April 2025). As detailed below – and throughout this document – Staff also puts forth a plan and rationale to revise the current IRP/CEP process to enable the Commission to consider the significant changes to the Preferred Portfolio and Action Plan that PacifiCorp plans to include in the IRP Update to be filed in April 2024.

Staff finds the 2023 IRP was an insightful first attempt at putting forth a comprehensive resource plan to meet HB 2021's decarbonization targets and community benefit goals while accomplishing traditional IRP analysis. PacifiCorp staff conducted more complex modeling than in any previous IRP and demonstrated a commendable level of engagement and candor with Staff and stakeholders. However, Staff has determined that a change of course in this IRP is necessary. This is spurred by two developments.

First, events outside the LC 82 process profoundly changed the relationship between this IRP/CEP's conclusions, action plan, and the market and policy realities faced by PacifiCorp. The two most notable of these events were the judgment against PacifiCorp in the wildfire lawsuits in August 2023 and the Tenth Circuit Court of Appeals' stay of the Ozone Transport Rule in July 2023. The combination of these two events, along with other events, led PacifiCorp to suspend its 2022 AS RFP in September 2023. As noted by many stakeholders in the first round of comments, the RFP suspension, which removed approximately 1.5 GW of new, non-emitting capacity by 2027 from the Preferred Portfolio, cast into doubt several important elements of the IRP/CEP. These included the Preferred Portfolio itself, many action plan items, and any understanding of the potential of forecasted emissions reductions to achieve CEP compliance. In short, the IRP/CEP map no longer matches the territory of operational and market realities. Thus, Staff and stakeholders argued in the first round of comments that additional analysis within this IRP/CEP was necessary in order for several elements to be acknowledged. Independent of these outside events, Staff and stakeholders also noted in Round 1 comments the need for improvements to the IRP/CEP to consider acknowledgement. These included:

- Including Oregon's Small Scale Renewable (SSR) requirement in the Preferred Portfolio in 2030 to capture the portfolio benefits of SSRs.
- Adding more energy efficiency (EE) in Oregon to reflect the higher value that EE brings to Oregon in the context of HB 2021.
- Utilizing more reasonable resource cost estimates.
- Addressing any identified errors with the granularity adjustments that PacifiCorp applied within its PLEXOS modeling.
- Analyzing the sufficiency of the Preferred Portfolio to enable simultaneous compliance with clean energy and GHG policies in Oregon, Washington, and California.
- Reoptimizing select portfolios for a clearer understanding of portfolio NPVRR and the ability to compare actions.

- Articulating more clearly the Oregon implication of coal-to-gas conversions vis-à-vis emissions, decarbonization efforts, and future MSP allocations.

While PacifiCorp has signaled an openness to eventually considering the improvements listed above, the Company was also clear that it would not conduct additional analysis to revise its filed IRP/CEP.[1] The Company has pushed all additional analysis or changes to this IRP/CEP to either the IRP Update or the next IRP.

While it would be unwieldy to constantly revise a filed IRP/CEP, additional analysis has been done in the past when staff or stakeholders indicate they cannot support acknowledgement without material revisions. Conducting additional analysis within the IRP/CEP timeframe to adjust to large-scale and material events impacting the Preferred Portfolio – or in response to stakeholder insights and requests – is reasonable. The IRP process is designed for rounds of comments to consider, discuss, and debate changes to achieve acknowledgement. Accordingly, the IRP/CEP is deemed reasonable to acknowledge at the end of the process, not upon filing.

Because PacifiCorp will not voluntarily make changes to this IRP/CEP, some of the most important issues before us lack a shared analytic foundation from which an acknowledgement determination can be made. As such, Staff does not see a path to recommending acknowledgment of PacifiCorp's current IRP/CEP. At the same time, Staff is concerned that non-acknowledgement and reconsideration at an undetermined future date could delay important activities that the Company must or should undertake to comply with HB 2021. Time is limited for the utility to adopt a CEP that can be acknowledged and successfully implemented before the first emissions reduction target in 2030. Given this tension and the indications from PacifiCorp that there will be significant changes to the Preferred Portfolio and Action Plan in the IRP Update to be filed in April 2024, Staff recommends that the schedule be updated to allow the Commission to consider the information in the forthcoming IRP Update. Staff also recommends that PacifiCorp be directed to address, within the IRP Update, a limited number of threshold issues that have been raised within this docket.

Specifically, Staff recommends that PacifiCorp be directed to, at a minimum:

- Align the updated Preferred Portfolio and Action Plan with PacifiCorp's updated plans in light of key developments since the filing of the IRP, including the suspension of the 2022 AS RFP and the stay of the Ozone Transport Rule.
- Include Oregon's Small Scale Renewable requirement in the updated Preferred Portfolio.
- Confirm that the updated Preferred Portfolio can support simultaneous compliance with the clean energy requirements and GHG targets in Oregon, Washington, and California.
- Fix any confirmed analytical errors identified in this docket, including any errors in the calculation or application of granularity adjustments.

With regard to the CEP, Staff believes that the changes to the Preferred Portfolio in the IRP Update may significantly impact PacifiCorp's Oregon-allocated GHG emissions and/or the allocation strategies

[1] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 96. "Pertaining to the 2022 AS RFP, PacifiCorp has no revised plan or substantive updates available at this time and is actively working to incorporate a number of updated assumptions as part of portfolio development for its 2023 IRP Update, anticipated to be filed April 1, 2024. The result will be comprehensive changes to the portfolio, and not just specific line items that could be modified in a few figures in the filed 2023 IRP."

needed for PacifiCorp to comply with HB 2021. Staff therefore recommends that PacifiCorp be directed to revise and resubmit the CEP so that the emission strategy and information on costs to Oregon ratepayers is consistent with the information in the IRP Update.

Staff also describes in these comments a number of issues regarding PacifiCorp's efforts to incorporate community impacts into planning decisions and presents a number of expectations regarding community engagement, community benefit indicators (CBIs), community-based renewable energy (CBREs), and resiliency. Staff views PacifiCorp's efforts on these fronts as important first steps upon which to build in future planning cycles. Staff does not expect the Company would make significant revisions in these areas prior to filing a revised CEP, but does expect the Company would update information in a revised CEP filing to the extent that their plans have changed.

To accommodate the timing of PacifiCorp's planned IRP Update filing, Staff proposes that the Commission take up these recommendations at the February 20, 2024, Public Meeting. This will allow Staff and stakeholders to focus the remaining efforts for this IRP/CEP on reviewing the April 2024 IRP Update and a revised and resubmitted CEP. Staff believes a revised CEP should be submitted with the IRP Update.

The table below summarizes those IRP items that Staff plans to recommend and not recommend for acknowledgement in LC 82:

Table 1: IRP Elements Recommended for Acknowledgement

	Acknowledge	Not Acknowledge
IRP	Eleven Action Plan Items (1a, 1b, 1e, 1f, 3a-3c, 3e, 4a, 6a, 6b) Load Forecast	Nine Action Plan Items (1c, 1d, 1g, 1h, 2a – 2c, 3d, 5a) Preferred Portfolio Long-Term IRP/CEP Strategy

Finally, Staff is incredibly grateful to the following stakeholders for their work in LC 82: Alliance of Western Energy Consumers (AWEC); Community Advocates; Columbia River Inter-Tribal Fish Commission (CRITFC); Oregon Citizens' Utility Board (CUB); Energy Advocates; Fervo; NewSun Energy LLC (NewSun); Renewable Northwest (RNW); Sierra Club; and Swan Lake and FFP Project 101. The comments and overall engagement throughout this IRP have deepened Staff's understanding of the issues surrounding HB 2021. They have also improved this IRP/CEP and future filings by PacifiCorp as they chart a pathway to a reliable, affordable, equitable and decarbonized system.

Key Challenges & Vulnerabilities

In Round 1 comments, Staff identified key challenges and key vulnerabilities to LC 82. The challenges represented issues within IRP and CEP that would require more explanation of the near-term resource strategy and general implementation. Staff's identified vulnerabilities represented more critical issues that called into question the ability to acknowledge a particular aspect of LC 82. While all of the identified topics from Round 1 are covered in these comments, we revisit the most pressing or unresolved items below.

Composition and Costs of Small-Scale Renewables and Community-Based Renewable Energy (Challenge)

In Reply comments, PacifiCorp addressed questions around costs and composition of SSRs. While the Company reasserted that SSRs remain uneconomic, the Company is clearly committed to trying to meet the 2030 SSR target in HB 2021.[2] Staff appreciates PacifiCorp's approach of letting the RFP run its course and then pivot to other methods of acquiring SSRs based on the RFP results.[3] Staff also appreciates PacifiCorp's thorough response on the potential barriers in Oregon rule to SSR procurement.[4] The Company's four suggestions provide a solid basis for fruitful public dialogue. Staff will not address each of the Company's suggestions in its comments, but would be open to participating or leading an informal public discussion on PacifiCorp's suggestions.

Both Staff and the Company see some overlap between CBRE and SSR projects.[5] However, PacifiCorp has modeled CBRE Projects and SSR projects separately, most notably with CBRE projects having a higher cost per MWh. PacifiCorp plans to acquire CBRE projects through a grant pilot program rather than an RFP.[6]

Staff would note the initial SSR RFP filing limits the range of projects from 3 MW to 20 MW. We think the bound at the low-end of the range may unnecessarily exclude potential CBRE projects that are smaller in nature. Staff will work to expand this range in the SSR RFP so that it can potentially capture these projects and establish two channels for acquiring this resource.

State Policy Compliance in IRP Portfolios (Vulnerability)

In Round 1 Comments, Staff raised a central concern to PacifiCorp's CEP compliance allocation methodology: would the Preferred Portfolio contain a sufficient amount of non-emitting resources in 2030 to simultaneously comply with the clean energy and GHG policies of Oregon, Washington, and California? Staff is concerned that if PacifiCorp continues to evaluate compliance with each state-level policy in separate analyses outside of the IRP, resources could be erroneously double-counted toward policy compliance in multiple states.

Staff requested that PacifiCorp demonstrate in this IRP that the Preferred Portfolio could simultaneously comply with clean energy and GHG policies in Oregon, Washington, and California and that, in future IRPs, the Company to constrain the Preferred Portfolio to ensure that simultaneous policy compliance is feasible.

PacifiCorp's Response Comments noted that, "there is no feasible single-pass modeling solution that guarantees Oregon compliance while simultaneously meeting all other portfolio requirements."[7] PacifiCorp also suggested that Staff's request to demonstrate simultaneous compliance of state-level policies would not be possible due to limitations of PLEXOS and the fact that resource allocations have not yet been determined.[8]

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[2] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 53.
[3] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 52.
[4] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 85.
[5] LC 82, PacifiCorp Clean Energy Plan, May 31, 2023, page 36.
[6] LC 82, PacifiCorp Clean Energy Plan, May 31, 2023, page 54.
[7] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 24.
[8] *Ibid*.

Yet elsewhere in PacifiCorp comments, the Company expresses openness to developing a more "unified" portfolio that integrates systemwide and state-level constraints.[9]

From Staff's perspective, ensuring that PacifiCorp can simultaneously comply with all state-level policies to which it is bound should be foundational to the Company's IRP process. Staff appreciates PacifiCorp's concern that a "single pass" modeling solution to this problem may not be available through the PLEXOS model. However, this limitation does not prevent PacifiCorp from demonstrating that simultaneous state-level policy compliance is feasible or ensuring that portfolios meet this requirement. PacifiCorp already uses multiple modeling passes to make adjustments to portfolios to respect other complicated constraints (e.g. the reliability and granularity adjustments). PacifiCorp could similarly adopt an iterative process within the IRP in the event that a portfolio was found not to comply with one or more state-level policies simultaneously.

Staff also appreciates PacifiCorp's concern that evaluating state-level policy compliance may require the Company to make assumptions regarding future allocation. However, Staff does not see this as an impediment to testing the feasibility of simultaneous policy compliance. PacifiCorp could, for example, demonstrate that there is some feasible allocation (i.e. all allocation factors fall between 0 and 1 and sum to 1) that achieves simultaneous policy compliance, without adopting that allocation strategy. Such an exercise could be used to test the limitations of what can be achieved through allocation and to identify if there are high-level constraints that could inform allocation discussions in MSP.

Because PacifiCorp would not or could not conduct this analysis – and given its centrality to the IRP and CEP – Staff conducted a high level and approximate exercise to make a "back of the envelope" determination of the non-emitting sufficiency of the Preferred Portfolio in 2030. Staff's simple analysis, which was based on public information from PacifiCorp's IRP and CEP workpapers, identified multiple energy allocation strategies for the Preferred Portfolio that would likely result in simultaneous policy compliance in Oregon, Washington, and California in 2030.

Further, the policy-feasible allocations that Staff tested also resulted in the majority of the load in Idaho, Utah, and Wyoming being met with non-emitting generation by 2030 under the Preferred Portfolio.

Staff's findings are in fact consistent with PacifiCorp's assertion that the proposed renewable additions originally proposed in this IRP are primarily being driven by economics, rather than policy compliance. Staff's analysis also bolstered Staff's view that it is reasonable for PacifiCorp to incorporate this type of analysis into future IRPs and IRP Updates.

Staff Expectations:

- In the next IRP, PacifiCorp should demonstrate that simultaneous compliance with all state-level policies is feasible with the Preferred Portfolio and with the Preferred Portfolio variants tested in the IRP.
- In the next CEP, PacifiCorp should transparently explore and describe constraints that HB 2021 compliance potentially places on allocation.

[9] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 54.

CEP Compliance Pathways (Vulnerability)

Staff finds that considering the effect of allocation pathways in the CEP on HB 2021 compliance is an acceptable, flexible approach to beginning a conversation about HB 2021 compliance that reflects how DEQ conducts annual emissions compliance evaluation. However, Staff also recognizes that it represents a complete departure from the allocation methodology approved in the 2020 MSP. Staff agrees with CUB that this was done with limited discussion outside of MSP. CUB observed that, beyond comparing compliance costs across portfolios, PacifiCorp's approach to developing CEP pathways – along with changes in coal retirements and this IRP's quick pivot to coal-to-gas conversions – represent a fundamental break from the approach of the 2020 Multi-State Protocol (MSP) with no transparent discussion or analytic demonstration of how these changes to the allocation methodology are in the best interest of Oregon.[10] Further, AWEC speculated that PacifiCorp's proposed pathways most likely exceeded HB 2021's incremental cost cap, that neither pathway can be enforced or guaranteed, and that because both pathways do not reflect the current MSP allocation they should be prohibited.[11] Both RNW and the Energy Advocates generally objected to PacifiCorp's approach as just an allocation exercise with no meaningful emission reductions and little chance of being accomplished within the MSP framework.

The Company's response points out that CEP pathways are compliant with the 2020 MSP prior to its expiration at the end of 2024, and that no MSP has been agreed upon for the time period after 2024 when most CEP cost will be incurred. Further, PacifiCorp counters CUB that the CEP does include cost analysis. The CEP pathways also represent issues to be considered in the current MSP negotiations, not actual positions that must be taken. To this end, PacifiCorp notes that the pathways were not the primary means to achieve CEP compliance. Rather, the IRP's proposed system-wide, Preferred Portfolio would in fact achieve 98 percent of the Oregon CEP emission reduction targets by 2030.[12] Finally, PacifiCorp argues for a narrow interpretation of HB 2021's cost cap that should be applied once costs are incurred and to conduct such an analysis in a rate case.[13]

Staff agrees with PacifiCorp that the expiration of the 2020 MSP provides a level of flexibility in proposing CEP compliance pathways. Yet the analysis in this CEP – while instructive and insightful –falls short of providing actionable insights *and* a forum to discuss the tradeoffs for Oregonians around MSP allocation methodologies capable of meeting HB 2021's goals. In this sense Staff agrees with CUB: by limiting the CEP pathways to only "illustrate" what could eventually occur in MSP, the IRP/CEP falls short of providing an actionable "plan" around which to debate the costs and risks of various CEP Compliance Pathways. Finally, Staff agrees with the Company's assertion that UM 2273 will be the best place to address policy issues around HB 2021's cost cap, not this IRP/CEP.

Staff Expectations:

- PacifiCorp should utilize its 2025 IRP public input workshops to clarify with stakeholders the relationship between MSP, IRP "actions," Oregon's CEP requirements, and Oregon's DEQ compliance methodology and explore improvements such that HB 2021 targets and activities are informative to and reflected in MSP decisions. As part of this process, changes to MSP disclosure rules should be explored to increase transparency.

[10] LC 82, CUB Round 1 Comments, October 25, 2023, page 5.
[11] LC 82, AWEC Round 1 Comments, October 25, 2023, page 3-5.
[12] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 23.
[13] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 26.

- To improve an understanding of tradeoffs in the IRP Update and/or as part of the revised CE, the Company should report Oregon-allocated costs and GHG emissions for the top performing IRP portfolios (inclusive of Oregon's SSR requirement) under various allocation pathways and that PacifiCorp.

Coal-to-Gas Conversions (Vulnerability)

In Opening Comments (Round 1), Staff recognized that PacifiCorp's 2023 IRP makes a significant departure from its 2021 IRP in its plans to retire coal-fired generation resources. Specifically, while the 2021 IRP only included gas conversions of Jim Bridger Units 1 and 2, the current plan adds Jim Bridger Units 3 and 4 and Naughton Units 1 and 2 to the list.

PacifiCorp's analysis shows that the conversions are selected by its optimization model based on economics. Staff appreciated this analysis and sought more information from the Company to better understand the cost and risks associated with these conversions for Oregon customers as well as the consistency of these actions with HB 2021 emissions reduction targets. Staff appreciates PacifiCorp's responses to some of the questions posed by Staff, however, expresses disappointment that the Company did not answer most of the questions posed by Staff.

In response to Staff's question regarding the prominence of gas conversions in this plan compared to the 2021 IRP, PacifiCorp explains that the previously realized benefits from Bridger 1 and 2 conversions in the 2021 IRP portfolio analysis prompted the Company to explore this option for the other coal plants, and the conversions were endogenously selected within its optimization model. The Company also points out that gas conversions identified in the 2021 and 2023 IRP are a better outcome compared to a new gas plant selected in its 2019 IRP. Further, the Ozone Transport Rule limiting nitrous oxide emissions also favors gas conversions over coal. PacifiCorp also sees benefits in using the converted plants as a backup resource to be used in "limited circumstances" as it integrates clean energy resources into its system. The delay in the Natrium demonstration project has further necessitated the conversion of the Naughton Units 1 and 2.

PacifiCorp did not provide explanations in its Reply Comments to Staff's other requests in which Staff sought to understand if the Company has evaluated the risks of these converted units becoming stranded assets, or what factors could alter the decisions around future coal plant retirement and conversions. Staff had also asked for an analysis with a portfolio variant that does not allow any conversion beyond Jim Bridger 1 and 2, and to test this variant across various gas and CO_2 price options. Staff expected PacifiCorp to either include this portfolio in its CEP alongside other high-performing portfolio variants or introduce constraints related to HB 2021 in its IRP analysis. PacifiCorp indicated that more detailed analysis around coal retirement and conversion options will be provided in its 2023 IRP Update due to be filed in April 2023. Staff looks forward to receiving the updated analysis and expects PacifiCorp to include a detailed analysis of risk of regrets, potential changes in future retirement and conversion plan and the portfolio variant that Staff suggested.

CUB pointed out that coal to gas conversions nullify the agreement reached in the 2020 Multi-State Protocol regarding Oregon's exit from these coal plants, which was key to the determination of the 2020 MSP agreement. CUB had also expressed concerns with the implications of coal to gas conversion for decommissioning and cost allocation to Oregon customers. PAC is inclined to address MSP issues in the MSP process. PacifiCorp indicated that the main component of gas conversion costs is the cost of natural

gas pipeline transport and therefore there is no significant impact on depreciation and decommissioning costs.

Energy Advocates commented that coal to gas conversion is not shown to be least cost least risk in the presence of HB 2021. PacifiCorp indicated that they provided economic analysis showing system benefits from conversion of all Bridger units and Naughton units (in both 2021 (JB1 and 2) and 2023 IRPs). Conversion should be consistent with HB 2021, since these plants would have lower emissions compared to before and will be operated with low-capacity factor but meet peak and reliability needs. In response to Energy Advocates' comments on whether the benefits from these conversions and costs will only be limited to Oregon customers, PacifiCorp replied that these plants will retire in 2037, before HB 2021's 2040 timeline, hence Oregon is not the only one sharing costs. Moreover, conversion costs are much lower than cost of new renewables.

Sierra Club had expressed concern around availability of firm gas capacity for the converted units. PacifiCorp did not disclose the pipeline information in its Reply Comments due to confidentiality agreements with third parties.

Staff believes that the Company's decision to continue to operate coal generation units as natural gas plants must be evaluated in the light of HB 2021. Staff understands that inter-state protocol and cost allocation concerns raised by CUB are vital and expects the Company to respond to those in the appropriate docket. Further, Staff understands that the conversions of Jim Bridger 1 and 2 was acknowledged in the 2021 IRP and the conversion plan for Naughton 1 and 2 is also well under way, and therefore these items are not appropriate action items for acknowledgement in this IRP.[14]

Staff Expectations:

- PacifiCorp should provide analysis around risk of regret for coal to gas conversions in its 2023 IRP Update.
- PacifiCorp remove Action Items 1c and 1d from the Action Plan because the Company has already taken these actions.

RFP Suspension

As previously noted in Staff's Round 1 comments, PacifiCorp recently suspended its 2022 All Source Request for Proposals (2022 AS RFP), which sought bids from resources capable of coming online by the end of 2026. The suspension raises concerns around the Company's ability to execute certain Action Plan items in the 2023 IRP and procure sufficient near-term resources to meet Oregon's HB 2021. RNW's Round 1 comment similarly noted the risk from this suspension and encouraged PacifiCorp to resume the RFP as soon possible or have the Commission to direct the Company to do so.[15]

PacifiCorp's Round 1 Response Comments did not provide much information to assuage 2022 AS RFP suspension concerns. The Company failed to address many of the questions raised by Staff and stakeholders. Despite stating previously in LC 82 that the greatest risk to the IRP was under procurement of resources, the Company now stated that it did not have any revised plan or substantive updates available that reflected the impacts of the RFP suspension.[16] However, the Company did state that it had

[14] PacifiCorp Response to Staff DR Nos. 222 and 223.
[15] LC 82, Renewable Northwest, Round 1 Comments, October 25, 2023, page 7.
[16] LC 82, PacifiCorp Reply Comments, page 96.

engaged in a bilateral effort to procure battery storage technology by June 1, 2026, and that in the IRP Update a new RFP may be put forth.

Given that the Preferred Portfolio included 2,531 MW of wind, 6,383 MW of solar, and 6,411 MW of battery capacity on the system by 2028, the impact of suspending a near-term RFP puts these builds at risk. In response to discovery, PacifiCorp confirmed that it is unable to procure the amount of wind and solar included in the Preferred Portfolio in years leading up to 2028.[17] Table 2 summarizes the difference in installed capacity between the Preferred Portfolio and the additions that may actually occur if PacifiCorp is unable to procure any additional new renewables, other than the bilateral storage mentioned above.

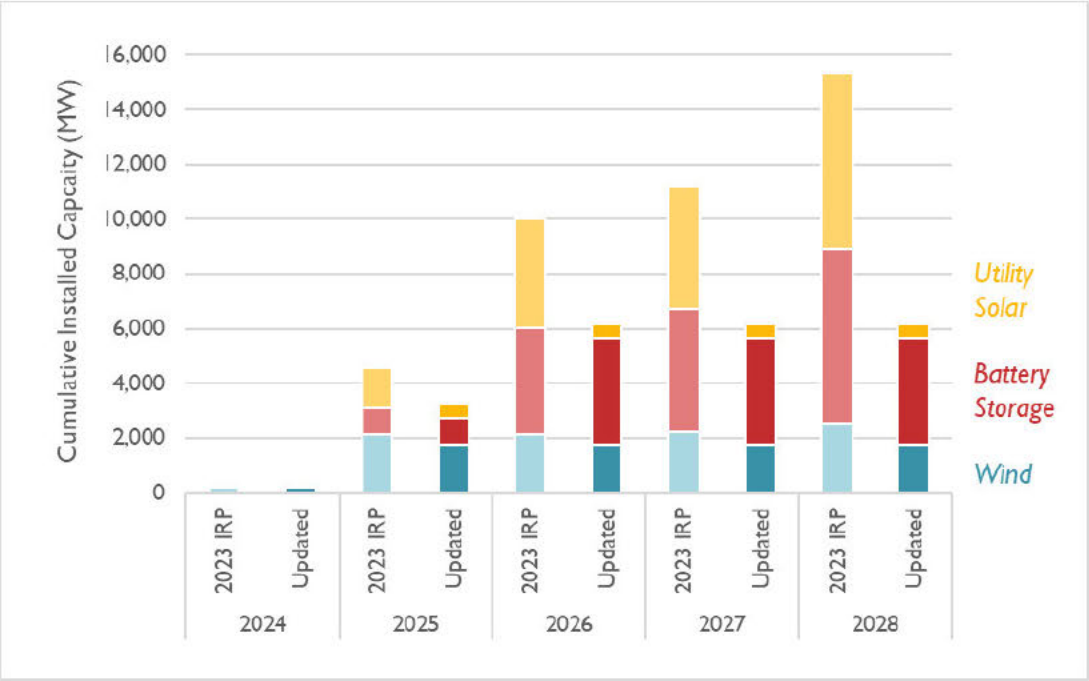
Table 2: Difference in Installed Capacity Between 2023 IRP Preferred Portfolio and Current Reality

Cumulative Installed Capacity Delta (MW)	2024	2025	2026	2027	2028
Renewable- Utility Solar	0	-974	-3,498	-3,981	-5,888
Renewable- Battery	0	0	0	-628	-2,528
Renewable- Wind	0	-339	-339	-439	-739
Total	**0**	**-1,313**	**-3,837**	**-5,048**	**-9,155**

The figure below demonstrates the impact that this delayed procurement could have on renewable resource builds over the next five years. The "2023 IRP" chart series on the left represents the data as presented in the Preferred Portfolio. The "Updated" chart series on the right represents capacity that PacifiCorp has currently indicated it can procure based on the 2020AS RFP and bilateral storage contracts. Solar is the resource that is most at risk due to the 2022AS RFP suspension, as the 2020AS RFP did not result in a large number of solar additions and PacifiCorp has not indicated any alternative procurement processes for solar.

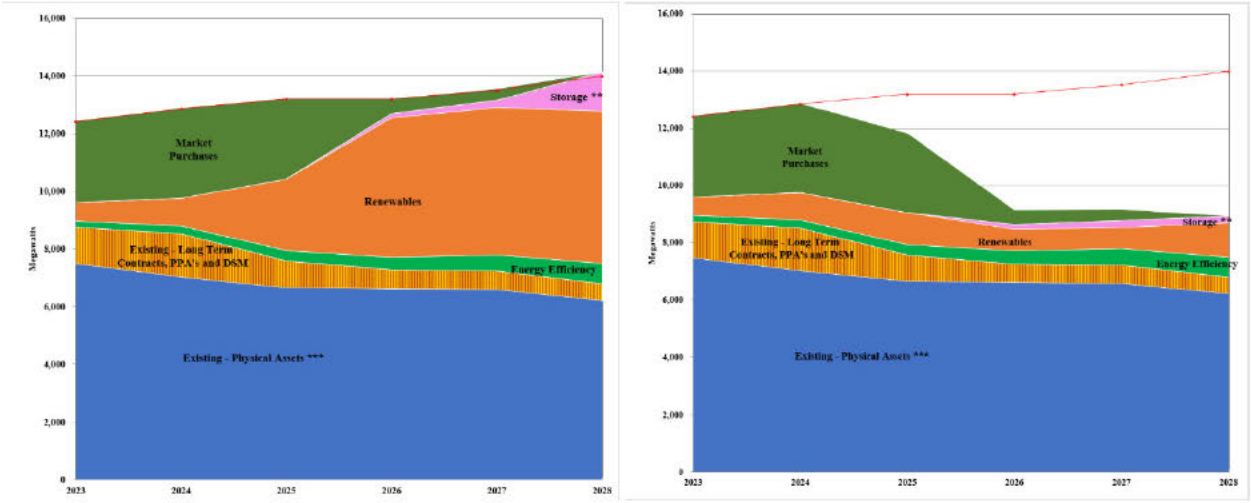
[17] PacifiCorp Response to Staff DR No. 243.

Figure 1. Difference in Installed Cumulative Capacity Between 2023 IRP Preferred Portfolio and Current Reality



This delay will also have a significant impact on the generation mix of the system. Figure 9.60 in the IRP shows the projected generation by resource type for the Preferred Portfolio. Over the next five years, PacifiCorp's Preferred Portfolio relied heavily on market purchases (also referred to as front office transactions or FOTs) and existing resources in the near-term while transitioning to rely more and more on new renewable resources. The left side of the figure below is a reproduction of Figure 9.60 as published in the IRP for years through 2028. The right side of the figure below demonstrates what the generation mix could look like if PacifiCorp does not procure new renewables and instead has a capacity mix that resembles the "Updated" chart series in Figure 9 above.

Figure 2. Reproduction of Figure 9.60 in IRP, with and without 2022AS RFP Suspension Impacts



Without the guarantee of additional solar, storage, and wind resources coming online over the next few years, PacifiCorp may end up relying more heavily on FOTs or delaying thermal resource retirements relative to the Preferred Portfolio. This could lead to decarbonization risks, which the Company has not adequately addressed in the current IRP.

As PacifiCorp will not remove the Action Plan items related to the 2022 **and** the proposed 2024 AS RFP from the filed IRP, nor update any analysis in this IRP/CEP to reflect the indefinite suspension of these procurements, the filed plans do not appear feasible. Staff finds little value in continuing to review this IRP/CEP. Too much is indeterminate and unknown. Further, as the CEP compliance pathways, and thus any determination of continual progress of emission reductions and compliance with the reduction targets, rests so squarely upon the IRP's Preferred Portfolio, without a revised analysis and procurement plan by PacifiCorp, Staff cannot determine the extent to which the CEP demonstrates compliance with the emissions reduction targets or can be substantiated to meet most if not all of the public interest factors detailed in HB 2021.[18]

Staff Recommendation 1. Do not acknowledge the IRP action plan elements 2b and 2c, the IRP's preferred portfolio, or the IRP's long-term plan.

Staff Recommendation 2. Direct PacifiCorp to seek acknowledgement of a revised Preferred Portfolio and Action Plan in the planned April 2024 IRP Update.

Staff Recommendation 3. Do not acknowledge the LC 82 CEP and direct PacifiCorp to revise and resubmit the CEP with its April 2024 IRP Update.

Action Plan Changes

PacifiCorp reply comments did not offer alternatives or revisions to the following Action Plan items that were impacted by events external to the IRP/CEP.

[18] See ORS 469A.420(2).

- Action Plan Item 1h: Per the non-confidential response to Sierra Club Information Request (IR) No. 37, the very near-term installation of the proposed selective, non-catalytic reduction (SNCR) installations at several coal plants is being paused and reevaluated due to the Federal Court stay of the Ozone Transport Rule.
- As noted previously all Action Plan Items Under Category 2 involve the acquisition of new resources either through the suspended 2022 AS RFP or through a proposed, new 2024 AS RFP. No alternatives or revisions to these activities were offered by the Company. Instead, PacifiCorp points to the potential for new procurements to be proposed with the April 2024 IRP Update.

Staff Recommendation 4. Do not acknowledge Action Plan items 1h and 2a.

CEP Comments

CEP acknowledgement hinges upon a finding that the CEP is, "in the public interest and consistent with the clean energy targets…" of HB 2021.[19] The recent order in UM 2273 provides an excellent overview of the public interest factors for valuating a CEP.[20] As noted above, given the Company's unwillingness to revise its analysis, Staff recommends not acknowledging the CEP. In the sections below, Staff details its determination that the community-focused elements of the LC 82 CEP appear reasonable with certain recommended changes, while the GHG emission reduction related portion of the CEP is not consistent with the clean energy targets nor does it appear to meet most if not all of the public interest factors detailed in HB 2021. For this reason, Staff does not recommend acknowledgement, but identifies portions of the CEP that may be included and/or improved in the revised and resubmitted CEP.

Community Benefits Indicators (CBI)

In Round 1 Comments Staff expressed concern that the interim CBIs provided no incremental information for evaluating the Company's IRP or CEP portfolios and did not materially affect its plans.[21] Staff requested that for the next IRP, the Company adopt CBIs representing the community impacts of energy efficiency, local non-GHG emissions from PacifiCorp facilities, and the Company's CBRE actions.[22]

The Energy Advocates recommend greater granularity for the Company's CBIs.[23] They also encourage the Company to include better measures of distributional justice when creating CBIs.[24] The Energy Advocates then state that the Company's CBIs do not offer any sense of how PacifiCorp brings economic benefits to communities,[25] a sentiment that is echoed by NewSun Energy.[26] The Community Advocates Cohort is discouraged by the lack of details in the Company's proposed CBIs and believes the Company's CO2 emissions CBI is not an indicator of community benefits.[27] Renewable Northwest (RNW) would like more detail about how the Company chose the 17 metrics that were included in the CEP.[28] RNW also recommends that the Company adopt additional environmental CBIs and believes that the language the Company uses when describing its resiliency CBIs expresses a hope instead of indicating that it is strongly committed to improvements or has any planned actions.[29] CRITFC supports past recommendations by the Energy Advocates to improve CBIs and wants better accounting for tribal needs in the Company's CEP.[30] In particular, CRITFC wants the CBI to incorporate tribal energy metrics and create metrics that target reducing peak loads, maximizing energy efficiency, strategically siting renewable resources, reducing reliance on Federal hydro resources, and minimizing the transmission and distribution system.[31]

[19] ORS 469A.420(2).
[20] UM 2273, Investigation into HB 2021 Implementation Issues, Order No. 24-002, Jan. 5, 2024, starting on page 17.
[21] Staff's Round 1 Comments, page 19.
[22] Staff's Round 1 Comments, page 21.
[23] Energy Advocates' Round 1 Comments, page 7-8.
[24] Energy Advocates' Round 1 Comments, page 11.
[25] Energy Advocates' Round 1 Comments, page 12.
[26] NewSun Energy's Round 1 Comments, page 6.
[27] Community Advocates Cohort's Round 1 Comments.
[28] RNW's Round 1 Comments, page 65.
[29] RNW's Round 1 Comments, page 65.
[30] CRITFC's Round 1 Comments, page 4.
[31] CRITFC's Round 1 Comments, page 7.

PacifiCorp stated in Round 1 Response Comments that it intends its CBIs to be a holistic representation of all the Company's activities to increase community benefits and highlights that it has added two new draft CBIs through its stakeholder process.[32] The Company states that it intends to refine its approach to resiliency and that there is additional work necessary to develop its CBIs.[33] In response to Staff's suggestion to frame CBIs as a metric rather than a goal, the Company states that it would consider it, but anticipates that it may cause confusion.[34] The Company did not appear to directly respond to any other concerns raised by Staff or stakeholders regarding CBIs.

Staff finds that the Company failed to fully respond to Round 1 comments by both Staff and stakeholders. In particular, the Company failed to:

- Provide any timeline to refine CBIs or provide any detail about how they could be refined.
- Discuss how it is attempting to implement tribal concerns brought up by CRITFC or greater CBI granularity brought up by Energy Advocates and Staff into CBIs.
- Discuss whether or how it would incorporate additional environmental CBIs into its next CEP.
- Provide any explanation about how the 17 metrics were chosen, as requested by RNW.

Staff agrees with the Company that developing CBIs is an iterative process that should be done in consultation with local communities and tribal governments. Staff is worried by the Company's apparent lack of response to published concerns by stakeholders, lack of record keeping, and lack of target timeline to improve CBIs. Staff would note the importance of maximizing to the extent possible Oregon community benefits across such planning activities such as portfolio development[35] and resource selection.[36] As such, relying solely on measures of systemwide impacts provides very little value when evaluating whether the Company's IRP and CEP provide tangible benefits to Oregon communities. Staff's Round 1 comments to recommended that CBIs better addressing energy efficiency, local emissions, and CBRE impacts were meant to bridge this gap.

With the following draft recommendations and expectations, Staff recognizes that the CBIs in this CEP are interim, but also seeks to stress the importance of using CBIs to meaningfully inform utility decisions and to track progress over time. Staff expects that the further development of CBIs be done in coordination with local communities and tribal governments and describes additional recommendations and expectations regarding this coordination in the Community Engagement section.[37]

Staff believes that in order to have an effective set of CBIs, it is critical to provide baseline measures of community impact prior to the next IRP/CEP update, and to develop more CBIs that address local non-GHG emissions, energy efficiency, and CBRE actions.

Staff Recommendation 5. Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.

[32] LC 82, PacifiCorp Reply Comments, page 13.
[33] LC 82, PacifiCorp Reply Comments, page 16-17.
[34] LC 82, PacifiCorp Reply Comments, page 18.
[35] UM 2225, Order No. 23-060, February 23, 2023, Appendix A, page 5.
[36] UM 2273, Order No. 24-002, January 3, 2024, page 23.
[37] UM LC 80, Staff's Round 2 Comments, page 31.

Staff Recommendation 6. Direct PacifiCorp to provide baseline metrics prior to filing its next IRP/CEP Update. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable.

Staff Expectations:
In the next IRP/CEP, Staff expects PacifiCorp to:

- Adopt CBIs representing the community impacts of energy efficiency, local non-GHG emissions from PacifiCorp facilities, and the Company's CBRE actions.
- Better inform CBIs and methods with input from stakeholders and community.
- Enhance tribal-focused CBIs.
- Use CBIs to better reflect the health impacts of EE.
- Provide portfolio analysis that allows more direct comparison of tradeoffs of different resource strategies e.g., more precisely capture the CBIs of portfolios.
- Enhance the ability of CBIs to better reflect the resiliency benefits of actions.
- Incorporate CBIs reflecting community-level impacts of non-GHG emissions, energy efficiency, and the Company's CBRE actions.

Community Based Renewable Energy (CBRE)

Staff found PacifiCorp's identified CBRE resources a reasonable starting point, but questioned whether more should be available based on a forecast of market activities not just existing programs. Staff also questioned whether net benefits were appropriately considered. Staff encouraged PacifiCorp to not limit CBRE potential to the activities and resources identified in the CEP and consider energy efficiency and flexible loads as potential valuable contributors. Lastly, Staff drew the connection between CBRE and SSR, and encouraged PacifiCorp to more aggressively pursue CBREs. Further, Staff encouraged PacifiCorp to pursue a CBRE strategy targeted at Oregon load pockets to avoid significant local transmission and distributions system upgrades.

RNW encouraged PacifiCorp to better quantify the benefits of CBRE and identify above market costs. Energy Advocates similarly encouraged PacifiCorp to consider broad benefits of CBRE, beyond a levelized cost of electricity analysis. RNW and Energy Advocates highlighted that PacifiCorp's CBRE potential relied on tallying existing programs which could be counted as CBRE. Both entities encouraged PacifiCorp to take initiative to identify additional CBRE resources. Energy Advocates highlighted that costs are likely inflated due to modeling not considering the IIJA and IRA. CUB raised government funding and questioned how funds may support CBRE development.

In response to Round 1 comments, PacifiCorp emphasized the Company's commitment to launching the CBRE Pilot proposal to external parties in the first quarter of 2024. The Company highlighted some of the ways in which the landscape of CBRE is quickly developing since the initial CEP filing. Of note, PacifiCorp anticipates a larger CBRE potential in Group B, siting 20 new projects in the pipeline. Initially, Group B included 3.5 MW of small-scale and community-focused renewable projects, primarily solar plus storage.

PacifiCorp commented on features of the Company's modeling that were raised by Staff and stakeholders. PacifiCorp clarified that the 10 percent adder was used to treat CBRE resources

commensurately with energy efficiency. For the CBRE scenario, PacifiCorp clarified that the Company had to force the model to acquire CBRE resources as the model would not have otherwise done so for cost reasons. Finally, PacifiCorp emphasized the dynamic nature of the planning environment for CBRE and committed to ongoing refinement of CBRE Pilot Approach. In particular, the Company resolved to support projects that are "in-flight" via other co-funding mechanisms and programs. PacifiCorp contends that despite commitment to ongoing improvement, costs were not inflated in this first round of analysis even though large federal legislation, namely the Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act (IIJA), were not included in initial analysis.

CBRE Resource Potential

Staff recommends that PacifiCorp consider more ambitious CBRE potential than the 95 MW identified, including 92 MW of which are in existing programs. The initial potential study tallied pending projects, and did not rely on forecasting sophistication of consumer adoption curves, historical cost declines, or enabling funding and programs. Staff appreciates PacifiCorp's acknowledgement that the 3.5 MW, Group B, potential is likely much greater due to new funding and programs. Due to rapid increases in renewable energy acquisition, Staff finds that 95 MW could significantly undercount the CBRE potential if effective program designs are deployed that recognize the benefits of CBRE, especially in the preferred portfolio.

Due to the magnitude of the 490 MW SSR requirement and the potential of CBRE resources to grow, Staff would like PacifiCorp to take a more aggressive approach than the "measured and incremental approach to investigating CBREs".[38] Staff encourages a sense of urgency and recommends PacifiCorp immediately publish the CBRE Grant Pilot Proposal to the CBIAG. Feedback should be solicited and processed quickly, such that PacifiCorp files the first round of the CBRE Grant Pilot for Staff approval by the end of Q2 2024. A quick feedback cycle is essential such that PacifiCorp may consider amending its CBRE potential based on feedback and results of an initial CBRE Grant Pilot.

Staff Recommendation 7. Direct PacifiCorp to pursue the CBRE Grant Pilot, contingent on the Company seeking feedback from the CBIAG in Q1 2024.

CBRE Activities

In the upcoming 2024 CEP update, Staff recommends PacifiCorp include an acquisition target of CBRE in its Action Plan. PacifiCorp's Round 1 comments identified a growing pool of known CBRE resources suggesting that 95 MW is likely a floor for a 2030 acquisition goal.[39] Many of PacifiCorp's CBRE actions are positive steps, but the current Action Plan, with no firm acquisition target, falls short of Staff's expectations. Staff appreciates that PacifiCorp continues to develop the CBRE Grant Pilot with stakeholders and is prioritizing "in-flight projects", such that the Company can accelerate how quickly those come online. Further, Staff expects PacifiCorp to be proactive beyond publishing a CBRE Grant Pilot. PacifiCorp should report regularly to the CBIAG on development activities, including on concrete actions PacifiCorp takes to reduce barriers, accelerate deployment, and expand CBRE potential.

Staff Expectation:

- Report regularly to the CBIAG on development including concrete and proactive activities PacifiCorp takes to reduce barriers, accelerate deployment, and expand CBRE potential.

[38] LC 82, PacifiCorp Reply Comments, page 4.
[39] LC 82, PacifiCorp Reply Comments, page 92.

CBRE Inclusion in Preferred Portfolio

In Portland General Electric's (PGE) 2023 IRP/CEP, PGE clearly communicated the fixed cost minus the benefit streams of CBRE resources. PGE's modeling selected the entire 155 MW of CBRE potential for the resource's value within the balancing authority.[40] Acknowledging that PGE and PacifiCorp have different geographic and resource characteristics, PacifiCorp's load pockets are an example where prioritization for CBRE resources would maximize benefits to both individual communities and to all ratepayers.

Staff disagrees with PacifiCorp's blanket characterization that a commitment to pursuing CBRE resources would break from historical least-cost, least-risk paradigm. Much of the CBRE resources identified have complementary, non-ratepayer sources of funding to reduce costs and avoid separate SSR procurement. As PacifiCorp acknowledged, the IRA and IIJA incentives were not accounted for in CBRE analysis which both reduces the potential and inflates the cost. Further, as was raised by Energy Advocates and RNW, PacifiCorp did not provide a transparent accounting of the benefits of CBRE resources to the system, particularly with respect to investments that can be avoided as a result. Without this clear articulation of value and despite PacifiCorp's claims of "considerable favor to SSRs" in PLEXOS modeling, Staff is not persuaded that all CBRE resources are as uneconomic as the Company portrays.[41]

Also undermining PacifiCorp's argument that pursuing CBRE breaks from the least-cost, least-risk paradigm is the fact that the Company's potential study found 92 MW of CBRE in existing programs. Proper cost consideration should have included these resources in the IRP preferred portfolio. Staff expects PacifiCorp to include these CBRE resources in the 2024 IRP update preferred portfolio and to update the CBRE potential in the 2024 CEP update.

Staff requested PacifiCorp address CBRE's role in minimizing costs in Oregon's load pockets.[42] PacifiCorp acknowledged the request but failed to respond in a quantitative manner. Staff highlights that PacifiCorp is versed in the dynamics of storage as a tool to manage transmission constraints, as section 6 in Round 1 comments includes robust discussion of specific examples (storage in lieu of B2H) and general agreement that less transmission expense is a "chief advantage of SSR".[43] However, it is unclear whether the Company applied a commensurate benefit to small scale and customer sited renewables and storage.

Staff Expectations:

In the IRP/CEP update:

- Include at least 92 MW of CBRE in the preferred portfolio, depending on the current pipeline of existing programs.

By the next IRP/CEP:

- Highlight and communicate the relative benefits of CBRE in load pockets.

[40] See Docket No. LC 80, *Portland General Electric 2023 Integrated Resource Plan and Clean Energy Plan,* Figure 77. Net cost of a microgrid CBRE, page 251, https://edocs.puc.state.or.us/efdocs/HAA/lc80haa8431.pdf.

[41] Id., page 84.

[42] Staff Round 1 Comments, DR No. 16, page 25, https://edocs.puc.state.or.us/efdocs/HAC/lc82hac144131.pdf.

[43] LC 82, PacifiCorp Reply Comments, page 53, https://edocs.puc.state.or.us/efdocs/HAC/lc82hac1546.pdf.

- Quantify the costs and benefits of CBRE for meeting HB 2021 guidance to "[e]xamine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy."[44]
- Identify one or more new, specific CBRE resource opportunities in Oregon and report on findings regarding specific costs and benefits.

CBRE Program Design

Staff encourages PacifiCorp to consider CBRE program designs that scale quickly and provide meaningful capacity distributed across the geographically diverse territory and specifically to load pockets. Staff highlights Green Mountain Power's (GMP) residential storage programs that have 1.1 percent of customers enrolled today and are poised to double annual customer acquisition rates.[45] A similar program growing at the same, per capita rate as GMP's could add 200 MW of distributed storage capacity to PacifiCorp's Oregon territory by 2030.[46] GMP's rate-based cost to operate the programs is reduced by the benefit of a 30 percent federal tax credit, monthly customer participation fees, and GMP's ongoing economic dispatch of the aggregated capacity. Over the system's lifetime, GMP identifies a positive lifetime net-present value of $2,749, despite the upfront, fixed cost of $22,000.[47]

Staff highlights Green Mountain Power as an example of a program design that delivers resilience, helps increase renewables adoptions, and scales quickly. Staff encourages PacifiCorp to be more expansive in its consideration of CBRE resources and consider additional energy efficiency and demand response capacity. For example, many buildings and communities across the state lack basic weatherization and existing programs are not scaled up to meet the need. In one example, the Northwest Energy Efficiency Alliance's 2016-2017 Residential Building Stock Analysis showed that 11 percent of Oregon's single family homes have uninsulated walls.[48] Efficient buildings that can maintain comfort during severe heat and cold events deliver not just energy savings but are better able to participate in demand response programs and deliver capacity savings.

Staff Expectation:

- Engage the CBIAG on potential program designs that can scale quickly to meet community and system needs.

Community Engagement

In Order No. 22-390, the Commission adopted expectations for PacifiCorp and PGE to furnish details on community engagement.[49] PacifiCorp used its existing IRP public input process, DSP efforts, and CETA Washington Equity Advisory Group as the basis of its CEP engagement efforts. The Company's

[44] ORS 469A.415(4)(d).

[45] Howland, Ethan, *Vermont PUC lifts caps on Green Mountain Power battery storage programs with Tesla, others,* Utility Dive, Aug. 29, 2023, https://www.utilitydive.com/news/vermont-puc-green-mountain-power-gmp-battery-storage-programs-tesla/692052/.

[46] Ibid. GMP anticipates growth of 474 residential battery installs per 100,000 customers. At 10 kW capacity per install, PacifiCorp's 610,000 customers could accumulate 200 MW of capacity by 2030.

[47] Ibid.

[48] *Residential Building Stock Assessment II Single Family Report,* Northwest Energy Efficiency Alliance, April 2019, neea.org/img/uploads/Residential-Building-Stock-Assessment-II-Single-Family-Homes-Report-2016-2017.pdf.

[49] *In the Matter of Near-term Guidance on Roadmap Acknowledgement and Community Lens Analysis the First Clean Energy Plans*, Docket No. UM 2225, Order No. 22-390, Appendix A at page 54 (October 25, 2022) *corrected,* Order No. 22-470 (December 5, 2022).

engagement efforts consist of customer surveys, sharing the Company's planning decisions at public "stakeholder engagement venue" meetings, and a Feedback Tracker to document the Company's response meeting questions and comments. The engagement venues include, among others, a CEP Engagement Series, the Community Benefits and Impacts Advisory Group (CBIAG), and the Oregon Tribal Nations Clean Energy Engagement Series.

Staff Round 1 Comments asserted that PacifiCorp had not successfully articulated the Company's path from engagement and input to planning and action. While the CEP discussed tribal engagement opportunities, Staff found the CEP lacked detail on whether the Company had successfully incorporated Tribal perspectives into the Company's decision making and engagement strategy. Additionally, it was not clear that the Company's plan included the perspectives of environmental justice communities. To this extent, Staff suggested improvements including reevaluating the Feedback Tracker to include a clear description of why feedback was or was not included in IRP/CEP.[50] Going forward, Staff also recommended a dedicated stakeholder and cross-utility community engagement working group similar to that put forward in LC 80.[51]

In Opening Comments, the consensus among CUB, RNW, Energy Advocates, and Community Advocates, was that PacifiCorp had not meaningfully considered input from environmental justice communities. Energy Advocates and Community Advocates further noted that PacifiCorp had not measured the effectiveness of their engagement strategy. CRITFC advanced that there is no indication from the CEP or IRP that PacifiCorp has consulted with affected Tribes prior to making decisions, particularly around hydropower reliance.

In Reply Comments, PacifiCorp did not oppose working with PGE to create a common community engagement strategy group along the lines of Staff's suggestion.[52] PacifiCorp committed to timely updating the Feedback Tracker following public workshops,[53] but did not address Staff's additional suggestions to improve the Feedback Tracker. PacifiCorp stated the Company continues to pursue a dialogue with its sovereign tribal partners across its six-state service area and intends to hire a tribal-affairs representative. The Company further commented that it was developing a Tribal CBI focused on TE. PacifiCorp linked components of its DSP/Clean Energy survey to outreach and accessibility practices. Regarding environmental justice, the Company referenced an educational component at CBIAG meetings.

On December 19, 2023, following Round 1 Reply Comments, PacifiCorp met with Staff informally to explain how the Company had used the community engagement process to develop its Interim CBIs. PacifiCorp explained that, due to time constraints, the Interim CBIs presented in the CEP did not originate with the CBIAG. Instead, PacifiCorp selected CBIs previously developed through Washingtons' Clean Energy Transformation Act (CETA) engagement process. According to PacifiCorp, CBIAG members had approved of the Washington CBIs and also suggested additional CBIs; however, PacifiCorp stated at the meeting with Staff that it could not provide Staff with documentation of this approval or the

[50] *In the Matter of Near-term Guidance on Roadmap Acknowledgement and Community Lens Analysis the First Clean Energy Plans*, Docket No. UM 2225, Order No. 22-390, Appendix A at page 54 (Oct. 25, 2022) *corrected,* Order No. 22-470 (Dec. 5, 2022).

[51] *See In the Matter of Portland General Electric Company's 2023 Clean Energy Plan and Integrated Resource Plan*, Docket No. LC 80, Staff Round 2 Comments and Recommendations at pages 29-30 (October 24, 2023).

[52] LC 82, PacifiCorp Reply Comments, December 1, 2023, pages 10, 11.

[53] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 11.

proposed CBIs from CBIAG members[54] beyond the map showing the Company had opposed CBIs proposed by Joint Advocates that were not in line with the Washington CBIs.[55] Going forward, Company representatives committed to:

- Working with the CBIAG to evolve CBIs to be Oregon specific and reflective of CBIAG member feedback;
- Leveraging other efforts to inform and bolster CBIs, including through a 2023 survey and by developing channels to streamline community input from adjacent initiatives to CBIAG members; and
- Making changes to how the Company received and documented input to ensure CBIAG member feedback and knowledge was captured and could be referenced at a later date.[56]

After review of Stakeholder and PacifiCorp comments, Staff has identified the following key adjustments to the Company's platforms and methods that can improve community engagement in future CEP/ IRP processes.

Accountability and Transparency

PacifiCorp's CEP includes available venues for public input, yet the Company's community engagement strategy could be improved and ultimately more effective through better documentation of stakeholder input. This CEP did not provide a clear roadmap of how or why PacifiCorp used stakeholder input to inform the Company's IRP and CEP. Going forward, this documentation can help close the gaps between the Company's interpretation of effective engagement and stakeholders' priorities and expectations. Accordingly, Staff reiterates the need for Feedback Tracker improvements and looks forward to working with PacifiCorp and stakeholders to implement these improvements. Staff also recommends the utility conduct a participant survey on the engagement process before the next IRP/CEP filing. The survey should allow PacifiCorp to measure the effectiveness of the Company's engagement strategy efforts. Additionally, Staff expects PacifiCorp's CBIAG and CBI activities to better capture and document how Environmental Justice community priorities are addressed. Finally, as introduced in Round 1 Comments, Staff believes it is a priority to develop clear, actionable expectations for engagement in future IRP/CEP development and review. Consistent with LC 80, Staff recommends the establishment of a working group that can operate in coordination with the broader investigation into the Commission's planning and procurement policies in 2024.

Cross-venue Engagement Planning

Staff recognizes that stakeholder engagement addressing critical issues, such as wildfire risk, transportation electrification (TE), and energy affordability is occurring in separate dockets and venues outside of the CEP process. As discussed at the informal December 19 meeting with PacifiCorp, Staff is encouraged by the Company's work to streamline input channels. In the next CEP, Staff expects PacifiCorp to better articulate how it is leveraging stakeholder input and deliverables in these adjacent dockets and venues to inform CBIs, CBREs, and portfolio decisions.

[54] Staff and PacifiCorp meeting held December 19, 2023.
[55] PacifiCorp response to Staff DR 35 Attachment.
[56] Staff and PacifiCorp meeting held December 19, 2023.

Tribal Engagement

In Opening Comments, Staff recognized that engagement with Tribal Nations requires intentional recognition and a focused approach that the utility and industry as a whole is working to better understand and practice. Staff appreciates PacifiCorp's introduction of a Tribal TE CBI. Going forward, Staff expects the Company to provide updates to the CBIAG and Staff on the Tribal CBI development and strategy to actively increase Tribal Nation priorities in planning conversations and resource decision-making.

Notably, in December 2023, the U.S. Government reached a settlement agreement to support the Columbia Basin Restoration Initiative (CBRI) in partnership with the Six Sovereigns.[57] This comprehensive agreement leveraged the collective knowledge and priorities of Tribal Nations, Oregon and Washington states, federal agencies, and interest groups. The CBRI anticipates changes to the energy system as part of the work to restore fisheries while supporting decarbonization and resilient communities. For these reasons, Staff views the CBRI as an opportunity for PacifiCorp to improve its engagement strategy with Tribal Nations impacted by the construction and operation of the Columbia River Federal dams.

Staff Recommendation 8. Direct PacifiCorp to work collaboratively with Staff, stakeholders, peer utilities, and the CBIAGs in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs by December 31, 2024. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable, inclusive of the perspectives of peer utilities and the utilities' CBIAGs.

Staff Expectations:

- Staff expects PacifiCorp's CBIAG and CBI activities to better capture and document Environmental Justice community priorities.
- In the next CEP, Staff expects PacifiCorp to better articulate how it is leveraging stakeholder input and deliverables in related dockets and venues to inform CBIs, CBREs, and portfolio decisions.
- PacifiCorp should include the following additions and enhancements to the Feedback Tracker:
  - Organization/entity attribution or affiliation.
  - Flag for whether and where PacifiCorp incorporated the feedback into specific utility planning, actions, resource selection, and project prioritization.
  - Clear description of why feedback was or was not included.
- Staff encourages PacifiCorp to report on its Tribal engagement strategy by December 31 of each year to the CBIAG. The review should include successes, opportunities for improvement, feedback received, a discussion of Tribal CBIs and CEP/DSP project development, and any work to involve Tribal Nations in planning and resource decision-making.
- PacifiCorp should conduct a participant survey on the engagement process before the next IRP/CEP filing. The survey should allow PacifiCorp to measure the effectiveness of the Company's engagement strategy efforts.

[57] *See* Northwest Power and Conservation Council memorandum, *Report on the US Government Commitments: Power Related Topics*, January 3, 2024, https://www.nwcouncil.org/fs/18579/2024_01_p2.pdf. The Six Sovereigns include the Nez Perce Tribe, Confederated Tribes and Bands of the Yakama Nation, the Confederated Tribes of the Warm Springs Reservation of Oregon, the Confederated Tribes of the Umatilla Indian Reservation, and the States of Oregon and Washington.

Resiliency Analysis Framework

PacifiCorp's CEP outlines the beginnings of the Company's Resiliency Analysis Framework. The Resiliency Analysis Framework combines census tract level community[58] and utility[59] resilience scores into a composite community-resilience score. The Company plans to use the community-resilience score to identify census tracts for additional analysis and project prioritization.[60] After identifying threats, probabilities, and consequences, PacifiCorp plans to use a risk-spend efficiency (RSE) or cost-benefit analysis (CBA) to account for the costs at specific project locations. The Company's goal is to include resilience risk scores in project and program prioritization, including when assessing the IRP, CBRE, and SSR.[61]

In Opening Comments, Staff requested an update on the Resiliency Analysis Framework timeline, which includes PAC's plan to incorporate community-utility resilience scores and risk drivers into CEP program planning by Q1 2024.[62] By extension, Staff asked how the Company planned to use the Resiliency Analysis Framework in the IRP, CEP, and/or DSP. Staff also asked for additional information on the resiliency scoring metrics.

Energy Advocates and CRITFC argued that PacifiCorp should improve community resiliency and consider how SAIDI/SAIFI/CAIDI data can be connected with information about lived experiences and community resources that can be used during an outage. Energy Advocates added that PacifiCorp should clearly define resiliency in the CEP and improve the readability of the CEP to include important definitions for SAIDI, SAIFI, and CAIDI. CRITFC discussed the link between healthy salmon ecosystems, utility resource planning to meet HB 2021 requirements, and tribal community resiliency.

In Round 1 Reply Comments, PacifiCorp did not directly respond to requests for information about resiliency planning and community data points. Instead, PacifiCorp stated that much of Staff and stakeholders' comments, questions, and concerns would be addressed in the next CEP.[63] PacifiCorp's future planning approach will, "evolve as [the Company] gain[s] experience and receive[s]additional stakeholder input."[64] PacifiCorp explains that it is still evaluating how to include additional community input.

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[58] To develop the community resilience score, PacifiCorp assigns social vulnerability and community resilience scores to census tracts using FEMA National Risk Index (NRI) values. PacifiCorp response to Staff DR No. 97.

[59] To develop the utility resilience score, PacifiCorp applies System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI) including major events to calculate the annual number of customers and minutes interrupted at each transformer in each census tract. PacifiCorp response to Staff DR No. 97.

[60] For example, PacifiCorp explains that by sorting the largest census tract CAIDI values first, and then sorting by the lower NRI values the Company can identify customers experiencing longer system outages with lower community resilience or higher social vulnerability. PacifiCorp response to Staff DR No. 99.

[61] LC 82 PacifiCorp 2023 CEP, Resiliency, May 31, 2023, page 29.

[62] *See* LC 82 PacifiCorp 2023 CEP, Resiliency, May 31, 2023, page 32; *see also* PacifiCorp response to Staff DR No. 30.

[63] *See* LC 82, PacifiCorp Reply Comments, December 1, 2023, page 48 (In Round 1 comments Staff requested an updated Table 9 timeline. PacifiCorp acknowledged Staff's request in its Round 1 Reply Comments but did not provide an updated Table 9 timeline.); *see also* LC 82, PacifiCorp Round 1 Reply Comments, December 1, 2023, page 49 ("PacifiCorp is also evaluating how to apply its resilience analysis to DSP and CEP programs and will provide additional information in its upcoming CEP consistent with Staff recommendations. … PacifiCorp is currently developing a preliminary resilience cost-benefit analysis and will include this framework in its upcoming CEP.").

[64] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 48.

PacifiCorp did not address Staff's questions on how the Company's wildfire plan was incorporated into the CEP resiliency analysis beyond directing Staff to review the Company's Wildfire Mitigation Plan. PacifiCorp disagreed with Staff's assessment about its use of the terms "resiliency" and "reliability", but states it will be clearer in the next CEP. In response to Stakeholder requests, PacifiCorp has provided definitions of SAIDI, SAIFI, and CAIDI.

Staff also understands that PacifiCorp is currently evaluating the geographic scope of the Resiliency Analysis Framework to develop more granular resilience scores.[65] Of note, PacifiCorp's current methodology to calculate SAIDI/SAIFI/CAIDI scores at the census tract level results in higher values than under the traditional use, which applies these metrics to the state or utility level.[66] As stated in Staff Round 1 Comments, Staff is still interested in understanding how these census-level SAIDI/SAIFI/CAIDI data has been successfully used in the past for resiliency-related planning. Staff expects the Resiliency Analysis Framework to consider direct benefits to Oregon communities. Nevertheless, Staff is concerned that limiting the scope of resilience metrics to transformer outages within Oregon census tracts, as discussed in step two of the Resiliency Analysis Framework, may result in unnecessary grid-hardening at the expense of PacifiCorp's Oregon ratepayers or overlook cross-state resiliency issues such as wildfire, extreme weather, and load pockets.[67] Given the nascent state of the Resiliency Analysis Framework, Staff sees an opportunity to open discussions with the Company and Stakeholders on the appropriate geographic scope of the Resiliency Analysis Framework.

PacifiCorp states it accounts for non-energy related resilience assets and services in the NRI values.[68] As noted in Round 1 comments, the NRI values use well known indices and Staff continues to find them helpful. That said, Staff would like further insight on how the Company plans to consider these assets and services to meet its goal to prioritize enhancing community resilience over acquiring additional capacity[69] and avoid extraneous utility projects and their associated costs. Staff also expects further discussions between the Company, the CBIAG, Tribes, and Stakeholders on how NRI values can be tailored or supplemented to reflect specific community concerns and assets and leverage existing Company resilience plans, such as the wildfire mitigation plan in Docket No. UM 2207.

Staff understands that resiliency analysis is an evolving field and expects that PacifiCorp will significantly improve upon its Resiliency Analysis Framework in the next CEP. In the meantime, Staff recommends that PacifiCorp incorporate resiliency-related factors into the Q1 2024 SSR RFP and the CBRE Grant Pilot so that these efforts can bring tangible community benefits to their system.

[65] *See e.g.*, PacifiCorp response to Staff DR No. 96.

[66] LC 82, PacifiCorp 2023 CEP, CBI, May 31, 2023, page 20.

[67] *See e.g., In the Matter of Investigation into House Bill 2021 Implementation Issues*, Docket No. UM 2273, Order No. 24-002 at page 25 (January 5, 2024) ("Grid-connected facilities located outside Oregon contribute to reliable service for Oregon electricity customers and to reducing GHG emissions on the grid, and facilities located inside Oregon do not serve Oregon customers exclusively. There may be resiliency benefits to in-state resources and resource strategies that are worthwhile to consider, but those must be based on reliability and resiliency analysis or related valuation methodologies, not assumed based solely on geographic location or the presence of specific electricity market transaction receipts.").

[68] LC 82, PacifiCorp response to Staff DR Nos. 102, 104.

[69] LC 82 PacifiCorp 2023 CEP, CBRE, May 31, 2023, page 45; *see also* PacifiCorp response to Staff DR 109.

Figure 3: SSR RFP Procurement Timeline[70]

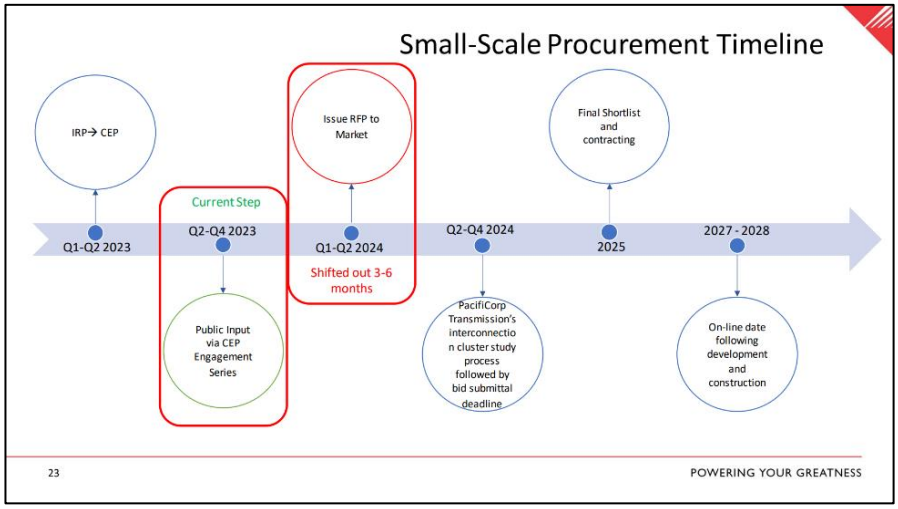
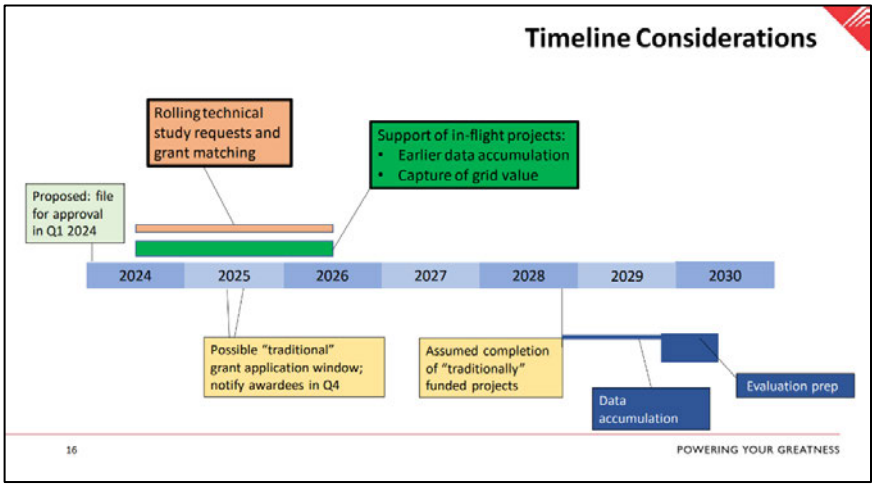


Figure 4: Timeline Considerations for the CBRE Pilot[71]



PacifiCorp's community-utility resilience score accounts for time and duration of outages through SAIDI/SAIFI/CAIDI metrics. It is not clear to Staff what additional information Stakeholders need regarding SAIDI/SAIFI/CAIDI methodologies and definitions. Prior to the next CEP filing, Staff expects PacifiCorp work with Stakeholders to identify gaps in Resiliency Analysis Framework comprehension and the vulnerabilities and complexities of these data sets as a measure of community level impacts.

[70] PacifiCorp CEP Engagement Series, 4th meeting, slide 23 (August 25, 2023) available at https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/cep/CEP_Engagement_Series_August_Meeting.pdf.

[71] PacifiCorp CEP Engagement Series, 4th meeting, slide 16 (August 25, 2023) available at https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/cep/CEP_Engagement_Series_August_Meeting.pdf.

Staff Recommendation 9. The SSR RFP incorporates into project selection criteria appropriate elements of the current Resiliency Analysis Framework and the CBRE Pilot be designed to promote resiliency-related factors.

Staff Expectations:

- PacifiCorp should specify how it intends to incorporate CBIAG feedback and other community input into the community-utility resilience scores and risk drivers by March 1, 2024.
- By the next IRP, PacifiCorp should explain how it will use the Resiliency Analysis Framework in IRP and CEP resource planning, project prioritization, and portfolio selection considering HB 2021's requirement that resiliency planning consider costs, consequences, outcomes and benefits.
- Prior to the next CEP, Staff expects the Company to open discussions with stakeholders on the appropriate geographic scope of the Resiliency Analysis Framework; work with Stakeholders to identify gaps in comprehension of the Resiliency Analysis Framework; and identify the vulnerabilities and complexities of SAIDI/SAIFI/CAIDI data sets and NRI values as a measure of community level impacts. The Company is encouraged to discuss how it can incorporate the lived experiences of communities into the community-resiliency score. The results of these discussions should be included in the next CEP.
- By the next CEP, PacifiCorp should be able to articulate further discussions between the Company, the CBIAG, Tribes, and Stakeholders on how NRI values can be tailored or supplemented to reflect specific community concerns and assets and leverage existing Company resilience plans, such as the wildfire mitigation plan in Docket No. UM 2207.
- At a CBIAG meeting before the next CEP and prior to any CBRE Grant Pilot project selection, provide details for how a completed Resiliency Analysis Framework will be used to impact project selection. Staff expects to work with PacifiCorp in helping to craft this presentation and what will be covered.

Acquisition of Federal Incentives

One of the specifically enumerated, HB 2021 public interest factors for weighing CEP acknowledgement is the extent to which the availability of federal incentives were considered.[72] In Round 1 comments Staff joined Sierra Club and CUB in calling for PacifiCorp to fully incorporate the financing opportunities and tax credits made available through the Interest Reduction Act (IRA) more fully into its IRP/CEP analysis. This included rerunning variant portfolios. Specifically: apply a 30 percent reduction to transmission network upgrade costs for low cost, renewable projects in select cluster study areas; and, assuming low cost federal financing and loan guarantees be used for targeted early plant retirements. Suggestions also included regular reporting to the Commission on progress pursuing federal incentives, exploring how Justice 40 incentives could be used for CBREs, and applying tax bonus credits to eligible "energy communities" in Oregon.

PacifiCorp responded that it used the available IRA information at the time of filing and continues to examine evolving legislation for use in future analysis where appropriate. Further, the Company stated that the PLEXOS model did account for federal incentives, as appropriate. The Company also shared that it was actively pursuing EIR programs, financing it can qualify for, and applying for grants and that it will communicate the details of IRA financing and other incentives as they become known. Finally, the Company stated that a variant study can be reported once the IRA financing details are better known.

[72] ORS 469A.420(2).

Staff appreciates all of the work done by PacifiCorp, stakeholders, and especially Sierra Club, to highlight the enormous cost-saving opportunities available through the federal government's IRA initiatives. However, this funding is limited to $2 Billion, expires in September 2026, and utilizes a first-come, first-served competitive application process. In short, time is of the essence if PacifiCorp wants to secure low-cost financing for planned investments to replace aging infrastructure.

Staff Expectations:

- The IRP Update includes two variant portfolios that directly reflect Sierra Club's suggested analysis around reduced upgrade costs and early retirements using the EIR program.
- PacifiCorp details in the IRP Update the timeline for submitting an EIR application and the scope of the projects it is seeking to be financed through the U.S. Department of Energy Loan Program Office's EIR program.
- PacifiCorp provides a brief update at every IRP public input meeting and every CBIAG meeting leading up to the 2025 IRP that details the Company's activities to apply for federal incentives and detailing any funding secured.

IRP Comments

In this section, Staff will not revisit all topics raised in our Round 1 comments on the IRP aspects of LC 82. Rather we have sought to prioritize those items which have the greatest bearing on acknowledgement/non-acknowledgement or are most critical for improvement in the next IRP/CEP.

Preferred Portfolio Modeling Process

Staff, RNW, and Sierra Club included an extensive number of comments on portfolio modeling for both improved development and selection. Most notable were the comments on the granularity adjustment, reliability adjustment, the inclusion of CEP resource additions (i.e., Oregon SSRs and higher levels of EE in Oregon), and the re-optimization of variant portfolios.

In developing the second round of comments, Staff's team explored the extent to which the processes around the granularity adjustment, the reliability adjustment, and portfolio reoptimization may have led to suboptimal portfolio development and selection.

Granularity Adjustment

In Round 1 comments, Sierra Club raised potential issues with PacifiCorp's application of granularity adjustments in their capacity expansion runs. PacifiCorp did not address Sierra Club's methodological questions about why the granularity adjustments did not seem to make sense and instead stated that there are "no logical alternatives" to the granularity adjustments, because they were "dictated by model math."[73] The Company's responses to earlier discovery from Sierra Club were similarly unclear.[74]

Staff engaged Synapse to further investigate the development and application of granularity adjustments. Synapse examined the workpaper that the Company used to develop the granularity adjustments,[75] and it identifies a potential errors and omissions in the calculations. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]. [BEGIN HIGHLY CONFDENTIAL]** [redacted] **[END HIGHLY CONFDENTIAL]**. Thus the Company may be adding erroneous adjustment factors to its capacity expansion modeling, which should be corrected. While the mistake does not appear to systematically favor **[BEGIN CONFIDENTIAL]** [redacted]

[73] LC 82, PacifiCorp Round 1 Reply Comments, page 39.

[74] Sierra Club Round 1 Comments, page 41.

[75] [redacted]

[END CONFIDENTIAL].

[BEGIN HIGHLY CONFDENTIAL]

[END HIGHLY CONFDENTIAL]. [BEGIN CONFIDENTIAL]

[END CONFIDENTIAL].[76] The inclusion of this adjustment introduces further subjectivity into the LT modeling and highlights the broader shortcomings of PacifiCorp's modeling approach.

[BEGIN HIGHLY CONFDENTIAL]

[END HIGHLY CONFDENTIAL]

The impact of the granularity adjustments, even with the limit of [BEGIN CONFIDENTIAL] [END CONFIDENTIAL], significantly changes the resource fixed prices. Figure 6 shows the capacity-weighted average fixed cost and granularity adjustments for each category of units. The granularity adjustments reduce fixed prices enough that they could have affected capacity expansion decisions in the model.

Ideally, PacifiCorp should improve the temporal granularity of LT modeling in future IRP proceedings so that granularity adjustments are no longer necessary. If this is not possible, the Company should at minimum revisit its methodology and correct its workpapers if necessary. It should also clearly explain

[76] PacifiCorp response to OPUC DR No. 240.

its methodology for this adjustment, including clarifying whether it uses the same set of granularity adjustments in each LT model run or whether it adjusts them iteratively. Importantly, PacifiCorp should be able to justify why its results, both with and without the price cap, are reasonable.

[BEGIN HIGHLY CONFDENTIAL]

[redacted]

[END HIGHLY CONFDENTIAL]

Reliability Adjustment

In Round 1 Comments, Sierra Club also raised concerns with the magnitude and potential subjectivity of the reliability adjustments that PacifiCorp made to optimized portfolios to meet reliability-based constraints. Sierra Club confirmed through discovery that PacifiCorp chooses which reliability adjustments to make based on the duration and timing of the shortage, the maximum size of the shortage in megawatts, and the location of the shortage.[77] However, the details of the Company's process are not transparent, including which resources it considers eligible for reliability adjustments and how it values eligible resources. As with the granularity adjustments, the Company stated in its Reply Comments that the reliability adjustments were "dictated by model math."[78] This explanation is even less satisfactory for the reliability adjustments than the granularity adjustments; while it is true that the model determines which hours have unserved energy, the decision about which manual adjustment to make in order to address this problem is at least partially subjective (as illustrated by the alternative portfolio of adjustments that Sierra Club developed for one of the variants in its Round 1 Comments).

[77] PacifiCorp response to Sierra Club DR No. 27.
[78] LC 82, PacifiCorp Reply Comments, page 39.

Staff engaged Synapse to further investigate the Company's reliability adjustments. Synapse confirmed Sierra Club's findings and similarly expressed concern regarding the magnitude of and lack of transparency in PacifiCorp's reliability adjustments.

Table 3 and Table 4 below quantify the reliability adjustments that PacifiCorp made in its preferred portfolio. The reliability adjustments more than triple the capacity of non-emitting peakers added during the study period, increase the amount of new batteries by 70 percent, and increase the amount of new solar by 26 percent. PacifiCorp shifted wind builds earlier, increasing the amount of new capacity by 129 percent between 2023 and 2030, but slightly decreasing the amount added over the entire study period.

In discovery, PacifiCorp stated that only non-emitting resources are eligible for reliability adjustments.[79] However, this is not quite accurate. The Company also manually adjusted the conversion and retirement dates for a number of its thermal resources. In the preferred portfolio, these adjustments took place in two stages. PacifiCorp started with a "Base" scenario, and then it hard-coded coal retirement dates and re-ran PLEXOS to produce a "Base Limited" scenario,[80] which it identified as the "initial" run used to create the preferred portfolio.[81] It then added further adjustments to produce the "reliable" portfolio. Table 3 cTable1ompares coal retirement and conversion dates across these three model runs. The large number of changes further underscores the extent to which PacifiCorp produced the preferred portfolio through manual adjustments, rather than configuring PLEXOS in a way that would allow it to optimize builds and retirements.

Table 3: Reliability Adjustments in Preferred Portfolio 2023-2030

	Builds in Initial Portfolio (MW)	Builds in Reliable Portfolio (MW)	Difference in Cumulative Builds/Retirements (MW)	Percent difference in Cumulative Builds/Retirements
Coal to Gas	375	1,770	1,394	371%
Coal – SNCR	(1,380)	-	1,380	-100%
Gas – EOL	247	247	-	0%
Nuclear	500	500	-	0%
Non-emitting peaker	-	606	606	Inf.
Battery	4,359	7,560	3,201	73%
Battery – LDES	482	-	(482)	-100%
Wind	1,934	4,431	2,497	129%
Solar	6,063	6,583	520	9%

Source: "(P)-LT-6529-23I.LT.Initial Run.20.PA0-.EP.MM.Base Limited.xlsx" and "(P)-LT-13338-23I.LT.Reliable.20.PA1-.EP.MM.PP-D3 29 v109.9.xlsx"

[79] PacifiCorp response to OPUC DR No. 233.
[80] PacifiCorp response to Sierra Club DR No. 40.
[81] PacifiCorp response to Sierra Club DR No. 25.

Table 4: Reliability Adjustments in Preferred Portfolio 2023-2042

	Builds in Initial Portfolio (MW)	Builds in Reliable Portfolio (MW)	Difference in Cumulative Builds/Retirements (MW)	Percent difference in Cumulative Builds/Retirements
Coal to Gas	(349)	0	349	-100%
Coal – SNCR	(2,335)	(2,335)	(0)	0%
Gas – EOL	(652)	(595)	57	-9%
Nuclear	1,500	1,500	-	0%
Non-emitting peaker	289	1,240	951	329%
Battery	4,643	7,910	3,267	70%
Battery – LDES	-	350	350	Inf.
Wind	9,251	9,113	(138)	-1%
Solar	6,246	7,855	1,609	26%

Source: "(P)-LT-6529-23I.LT.Initial Run.20.PA0-.EP.MM.Base Limited.xlsx" and "(P)-LT-13338-23I.LT.Reliable.20.PA1-.EP.MM.PP-D3 29 v109.9.xlsx"

Table1 5: Manual Changes to Coal Retirement and Conversion Dates in the IRP Preferred Portfolio

	Base	Base Limited	Reliable
Craig 1	Retires 2026		
Craig 2	Retires 2029		
Dave Johnston 1 and 2	Retires 2029		
Dave Johnston 3	Retires 2028		
Dave Johston 4	Gas conversion, retires 2040	Retires 2040	
Hayden 1	Retires 2029		
Hayden 2	Retires 2028		
Jim Bridger 1	Converts 2024, retires 2031	Converts 2024, retires 2031	Converts 2024, retires 2038
Jim Bridger 2	Converts 2024, retires 2030	Converts 2024, retires 2030	Converts 2024, retires 2038
Jim Bridger 3	Retires 2026	Unclear from workpaper	Converts 2030, retires 2038
Jim Bridger 4	Retires 2032	Unclear from workpaper	Converts 2030, retires 2038
Hunter 1	Retires 2031	SNCR, retires 2031	SNCR, retires 2032
Hunter 2	Retires 2031	SNCR, retires 2032	SNCR, retires 2033
Hunter 3	Retires 2030	SNCR, retires 2030	SNCR, retires 2033
Huntington 1	Retires 2030	SNCR, retires 2030	SNCR, retires 2033
Huntington 2	Retires 2026	SNCR, retires 2028	SNCR, retires 2033
Naughton 1	Converts 2026, retires 2032-2033	Converts 2026, retires 2032	Converts 2026, retires 2037
Naughton 2	Converts 2026, retires 2037		
Wyodak	Converts 2027, retires 2040	SNCR, retires 2040	

Source: "(P)-LT-6529-23I.LT.Initial Run.20.PA0-.EP.MM.Base Limited.xlsx," "(P)-LT-13338-23I.LT.Reliable.20.PA1-.EP.MM.PP-D3 29 v109.9.xls," "(P)-LT-6530-23I.LT.Initial Run.20.PA0-.EP.MM.Base.xlsx," and Sierra Club Round 1 Comments at page 19.

Staff shares Sierra Club's concerns about both transparency surrounding PacifiCorp's process for making reliability adjustments and the magnitude of the adjustments. The reliability adjustments substantially change the resources in the preferred portfolio, calling into doubt the extent to which PacifiCorp's capacity expansion is economically optimized.

Portfolio Reoptimization

Sierra Club's Round 1 comments also raised concerns regarding the inconsistency of PacifiCorp's practice of re-optimizing portfolio variants. Because re-optimization generally finds the lowest cost way to meet a portfolio's constraints, failure to re-optimize a portfolio could lead to an over-estimation of the costs associated with the specific resource variation being examined by that portfolio. This may lead some portfolio variants to appear artificially more expensive than others. In response to this concern, PacifiCorp noted that they have limited time to conduct re-optimization and must prioritize. Additionally, the variant portfolios identified by Sierra Club for re-optimization were generally meant to test through a counterfactual portfolio, a choice within or not included in the Preferred Portfolio (i.e., P-17's exploration of Colstrip's early retirement).

PacifiCorp's decision to not-reoptimize the PLEXOS LT model for variants P13, P18, and P19 causes the resulting portfolios to retain excess capacity that ratepayers do not necessarily need for a reliable system. For example, the resource builds, conversions, and retirements are identical between the Preferred Portfolio and P13– Max DSM, despite this variant installing an additional ~4,000 MW of DSM capacity over the time frame.

Regardless of the ostensible "purpose" of a variant portfolio, this approach fails to allow Staff and stakeholders to properly compare the preferred portfolio to other variants due to the overbuilt nature of the selected variants. As stated above, P18 results in PacifiCorp having an additional 2,000 MW of capacity starting in 2029, and P19 results in additional 500 MW of capacity starting in 2028. Even though PLEXOS ST captures any cost savings associated with dispatch, it is important for PLEXOS LT to be re-optimized as well to give the opportunity for additional cluster resource and DSM capacity to displace other new resource builds and/or identify earlier retirement dates for existing plants. Without re-optimizing PLEXOS LT, stakeholders are unable to easily tease out which resources would be displaced and how that would impact GHG and PVRR outcomes.

In discovery, PacifiCorp stated that three of the variant studies (P13, P18, and P19) were conducted with the understanding that additional resources would likely result in higher cost PVRR outcomes, and that the purpose of these variants is to assess the magnitude of the impact for determining possible least-regret paths to consider for the preferred portfolio.[82] While the results as presented in this IRP may still be of interest to the Company, PacifiCorp should not be doing this in lieu of re-optimization.

For example, the Max DSM variant as modeled is not currently providing much value for comparison to the preferred portfolio due to the magnitude of the incremental installed capacity that has been required (~4,000 MW) and the magnitude of the PVRR delta ($3 billion). The benefits of pursuing

[82] PacifiCorp response to Sierra Club DR No. 43.

ambitious energy efficiency and demand response are to reduce system load, peak demand, and firm capacity reserve requirement, thus avoiding investments in generation and capacity resources and transmission and distribution infrastructure. By not allowing re-optimization of this portfolio, PacifiCorp fails to allow for a significant portion of DSM benefits to be realized in the PVRR result. This variant design also fails to account for the potential of DSM to reduce the SSR and CBRE requirements, further reducing portfolio costs.

In future studies, PacifiCorp should re-optimize all future variant portfolios that add incremental capacity to the preferred portfolio. This will allow the Commission and stakeholders to assess all variant portfolios on an equal playing field. If a variant does not result in the addition or subtraction capacity from the portfolio and can be fully evaluated using PLEXOS ST only, re-optimization may not be necessary. If there is a scenario where PacifiCorp would legitimately be expected to maintain a system with more resources than needed to cost-effectively meet customer needs (e.g. P21), or if there is a legitimate reason the Company could not change its resource plans in time (e.g. P17), then studies without re-optimization could be used. If the Company is still interested in assessing the magnitude of incremental costs from hard-coded resources without re-optimization, this should be done outside of the variant case analysis.

Table 6 below summarizes PacifiCorp's variant portfolios and how they were modeled.

Table 6: Variant Portfolios

Scenario Name	Re-optimized builds?	If no, why not?	Future Recommendation
P01-JB3-4 GC	Yes		
P02-JB3-4 EOL	Yes		
P03-Hunter3-SCR	Yes		
P04-Huntington RET28	Yes		
P05-No NUC	Yes		
P06-No Forward Tech	Used P05		
P07-D3-D2 32	Yes		
P08-No D3-D2	Yes		
P09-No WY OTR	**No**	Used to evaluate the impact on P-MM if Wyoming's OTR was not enforced.	
P10-Offshore Wind	Yes		
P11-Max NG	Yes		
P12-RET Coal 30/33 NG 40	Yes		
P13-Max DSM	**No**	Used to evaluate the impact on P-MM if all DSM was selected.	Re-optimize capacity mix.
P14-All GW	Yes		
P15-No GWS	Yes		

Scenario Name	Re-optimized builds?	If no, why not?	Future Recommendation
P16-No B2H	Yes		
P17-Col3-4 RET25	**No**	Used to evaluate if earlier retirement of Colstrip 4 would result in energy or capacity shortfalls.	
P18-Cluster East	**No**	Used to evaluate the economic impact of adding the next best cluster resource to P-MM.	Re-optimize capacity mix.
P19-Cluster West	**No**	Used to evaluate the economic impact of adding the next best cluster resource to P-MM.	Re-optimize capacity mix.
P20-JB3-4 CCUS	Used P02		
P21-DJ2 CCUS	**No**	Used to evaluate the impact of installing CCUS at DJ2.	
P22-DJ4 CCUS	**No**	Used to evaluate the impact of installing CCUS at DJ2.	
P23-RET Coal 30/33	Used P12		
P24-Gas 40-year Life	**Yes**		

Staff Recommendation 10. Direct PacifiCorp to fix any confirmed analytical errors in the calculation or application of granularity adjustments.

Staff Expectations:
Before the next IRP, PacifiCorp should:

- Work with interested participants from the IRP Public Input process to develop and publicly produce a granularity adjustment methodology.
- Increase transparency around reliability adjustments by stating which resources will be eligible to be included as reliability adjustments in the next IRP and how each one will be valued. Further, it should clarify its modeling approach around how to limit the magnitude of the reliability adjustments that it must make.
- Solicit suggestions through the IRP Public Input process and as part of the Draft IRP of variant portfolios.

As part of the next IRP, PacifiCorp should:

- Adjust its modeling approach to better capture resource adequacy needs and the capacity contributions of resource options to reduce the need for and magnitude of reliability adjustments to portfolios.
- Reoptimize variant portfolios that add resources to the preferred portfolio unless there is a clearly explained reason to study an un-optimized portfolio of resources.

Coal Strategy

In its Round 1 Comments, Sierra Club raised concerns about the coal prices that PacifiCorp used in its modeling, which may have erroneously delayed the economic retirement date for Jim Bridger 3 and 4.[83] These units, which are co-owned by PacifiCorp (67 percent) and Idaho Power Company (33 percent) **[BEGIN HIGHLY** [redacted] **[END HIGHLY CONFIDENTIAL]. [BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**[86]

Fuel costs influence unit economics, so it is important for PacifiCorp to represent them correctly within PLEXOS so that the model is able to determine economic retirement and/or conversion dates. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted]

	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]

Sources: [redacted] **[END HIGHLY CONFIDENTIAL].**
[BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL].**

PacifiCorp's Round 1 Response Comments suggested that the Company accounted for the full cost of coal in the IRP, but represented some of the costs as fixed, rather than modeling all coal costs as variable.[88] **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL].**

[83] Sierra Club Round 1 Comments, page 44.
[84] [redacted]
[85] [redacted]
[86] [redacted]
[87] *Ibid.*
[88] LC 82, PacifiCorp Reply Comments, page 82: "PacifiCorp did incorporate significant fixed costs for coal supply to Jim Bridger units 3 & 4."

However, PacifiCorp added the fixed costs for coal supply at Jim Bridger in post-processing rather than modeling them within PLEXOS.[89] As a result, PLEXOS sees only the variable portion of the coal cost (blue line in [redacted]. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Unrealistic coal prices within PLEXOS may make Jim Bridger 3 and 4 appear more economic than they are in actuality, which could result in PLEXOS selecting a delayed economic retirement date. In the future, PacifiCorp should correct its PLEXOS modeling so that the full cost of coal at Jim Bridger is represented within the model.

[BEGIN HIGHLY CONFIDENTIAL]

[redacted]

[END HIGHLY CONFIDENTIAL]

Sources: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**

[BEGIN HIGHLY CONFIDENTIAL] [redacted] **[END HIGHLY CONFIDENTIAL].**

Hunter and Huntington

Two of PacifiCorp's coal plants, Hunter and Huntington, are located in Utah and have experienced the impact of disruptions to the Utah coal market for reasons such as the Lila Canyon mine fire and unfavorable coal mining conditions. While it can be hard to fully predict future disruptions to coal markets and resulting impact on fuel prices, it is important to incorporate as much up-to-date information as possible in order to ensure model results are reasonably similar to reality. Synapse, on behalf of Staff, reviewed federal Department of Energy EIA 923 fuel receipts data for 2023 and determined that PacifiCorp paid between $1.79 and $4.19 per MMBTU for coal at Hunter. At Huntington, Synapse determined that PacifiCorp paid between $2.18 and $2.54/MMBTU.

[89] PacifiCorp response to Staff DR No. 228.

[redacted]



[redacted]

[END CONFIDENTIAL].

On April 3, 2023, PacifiCorp filed its Transition Adjustment Mechanism in Docket No. UE 420 to update its net power costs for 2024. In Witness Owen's testimony, he states that "the significant production shortfall due to the Lila Canyon mine fire negatively affected all large coal consumers including PacifiCorp. Unfortunately, this negative impact is expected to continue into the foreseeable future."[92] If this is PacifiCorp's current position, then the 2023 IRP Update should incorporate the lasting impacts of unfavorable market conditions into its coal price forecast for these Utah plants.

[90] Confidential Attachment OPUC 229, "HTR-HTG Coal Update_2022 12 21 CONF".

[91] US Bureau of Land Management. 2022. *The Bureau of Land Management issues decision on Lila Canyon Mine.* Available at: https://www.blm.gov/press-release/bureau-land-management-issues-decision-lila-canyon-mine.

[92] *In the Matter of PacifiCorp's 2024 Transition Adjustment Mechanism*, Docket UE 420, Exhibit PacifiCorp/200, Owen/4.

Staff Expectation:
In the next IRP PacifiCorp should:

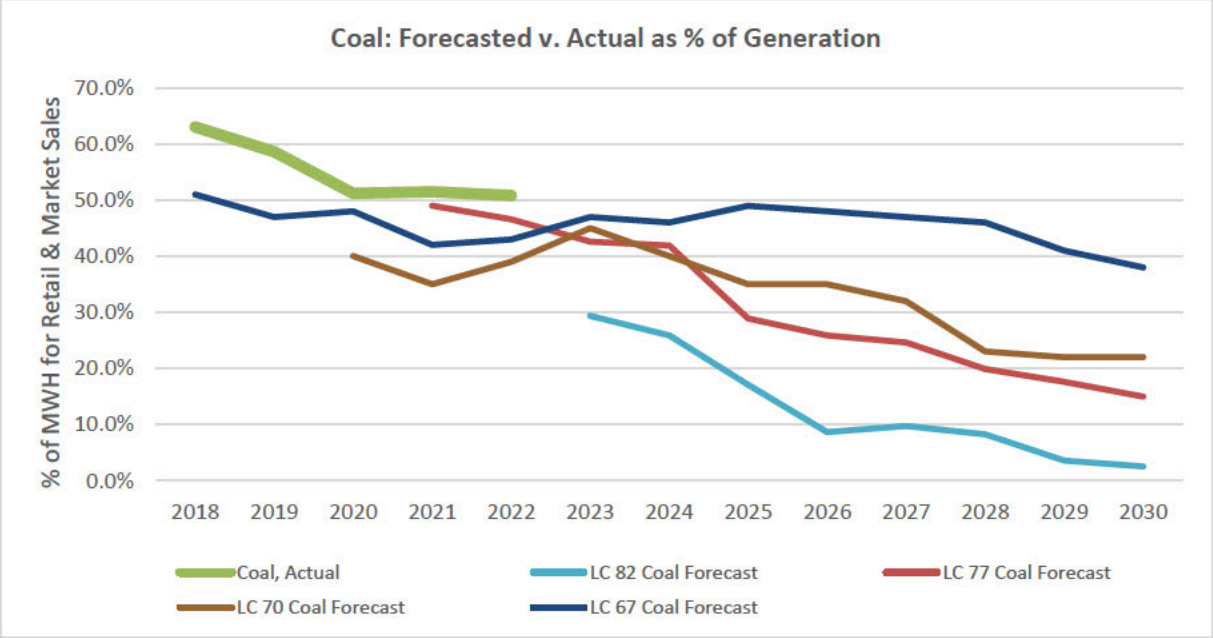
- Utilize coal prices for Jim Bridger that are reflective of actual costs from the Long-Term Fuel supply contract.
- Provide a full update on Utah coal supply issues.

Carbon Price Path

At the LC 82 Special Public Meeting on December 12, 2023, Bob Jenks of CUB raised an interesting point regarding PacifiCorp's use of carbon pricing. He noted that PacifiCorp's IRPs generally begin to apply a price to carbon two years after the IRP. This has the effect of reducing forecasted emissions in the IRP, especially from coal plants, as PacifiCorp's models internalized this carbon price into simulated, future operations. CUB suggested that because a true carbon price has never actually internalized into operations, real-life emissions are systematically higher than IRP modeled GHG emissions. CUB also noted in its Round 1 comments that an effective GHG price could be developed by forecasting, "...the annual cost of carbon from wildfires (prevention and insurance), divide that by its carbon emissions, and allocate the costs of emissions directly to the emissions themselves." [93]

Staff conducted a brief analysis forecasted to actuals in an attempt to substantiate CUB's comments regarding the disconnect between planning that uses a carbon price and actual coal operations.

Figure 8: 3Comparison of Forecasted v. Actual Coal Use as Percent of Generation



Staff's simple analysis would seem to corroborate CUB's concerns regarding the realism of PacifiCorp's modeled coal dispatch in the IRP. Staff raised a similar concern in UM 2225 in discussing the role of

[93] CUB Round 1 Comments, October 25, 2023, page 8.

operational changes in achieving GHG reductions and the Commission adopted the following expectation:

> *For the first CEP and associated IRP, if the Preferred Portfolio relies on operational changes relative to expected economic dispatch to reduce GHG emissions, including, but not limited to, application of operating or emissions constraints, inclusion of a GHG emissions cost in dispatch decisions, or out-of-state sales of fossil fuel generation, the utility should:*
>
> - *Quantify the impacts of those operational changes relative to expected economic dispatch in terms of generation (curtailed, reduced, or sold) and GHG emissions (avoided); and*
> - *Describe how the utility intends to implement those operational changes (e.g. through the development of operating or emissions limits, application of GHG emissions penalties, or execution of contracts with out-of-state entities), to the extent that they impact forecasted GHG emissions in the Action Plan window.* [94]

Accordingly, if the GHG emissions reductions in the CEP depend on the reduction in coal generation that results from applying carbon prices to dispatch, Staff would expect PacifiCorp to quantify those impacts in terms of both generation and GHG emissions, relative to an assumption of economic dispatch without carbon prices.

Importantly, PacifiCorp removes all coal from Oregon rates prior to 2030 per SB 1547 and so Staff expects this issue may only affect the Oregon-allocated GHG emissions in the 2020s. Nevertheless, PacifiCorp's use of GHG prices in modeling operations could be resulting in an unrealistic trajectory of GHG emissions reductions and the lack of an operationalized carbon price could therefore affect PacifiCorp's ability to demonstrate continual progress in the 2020s.

Staff fully supports PacifiCorp's use of GHG prices in portfolio design to capture the risk of future GHG policies. However, Staff is concerned that including GHG prices in the dispatch simulation that informs the Company's Oregon-allocated GHG emissions could be resulting in an unrealistic GHG reduction trajectory.

Staff Expectation:
In the next IRP/CEP PacifiCorp should:

- Recreate the chart above for (a) coal and (b) Oregon allocated GHG emissions comparing past IRP forecasts to actuals.
- Provide a sensitivity that calculates Oregon-allocated GHG emissions under the assumption of no carbon prices operationalized in dispatch. This sensitivity should still be based on the Preferred Portfolio, which considers a carbon price in investment decisions.
- Propose a PacifiCorp specific carbon price that layers atop the medium carbon price the Company's annual cost from wildfires as described by CUB.

[94] Order No. 22-446, Appendix A at page 21.

Candidate Resource Costs

In Round 1 comments, stakeholders raised concerns that PacifiCorp incorporated unreasonable price escalations for renewable resources. RNW's Round 1 Comments raised concerns on the cost assumptions PacifiCorp applied to its clean energy and energy efficient technologies, which include solar, wind (land-based and offshore), and storage resources.[95]

PacifiCorp sourced its cost data from WSP, an engineering and professional services firm, and later made some adjustments to the cost data to align with its view of future renewable resources market conditions.[96] WSP had relied primarily on the 2022 NREL ATB study to formulate renewable cost forecasts. The IRP states that PacifiCorp's cost-escalation curve differs from the NREL ATB forecast to account for observed market conditions, such as supply chain issues and long construction lead times.[97] RNW found that the company's ambiguous modifications to WSP's renewable resource cost estimates results in cost escalations that are 15-50 percent higher through the years 2023-2030.[98] PacifiCorp's sources or methodology behind large price escalations remain unclear. PacifiCorp has not clearly explained its resource cost modifications besides the "recent tighter trade tariff and inflation" observed in 2022.[99]

Staff agrees with RNW that the long duration of these high prices assumptions are concerning and not well proven. Manual adjustment of cost assumptions most likely affects resource selection and the preferred portfolio's economics.[100, 101] Due to the high capital cost forecast for renewable resources in PacifiCorp's IRP, the model selects over a GW of nuclear and non-emitting peaking resources through the years of cost escalations.[102]

While it is reasonable to assume cost escalations due to recent market conditions, PacifiCorp's estimates are far above the consensus. Compared to other studies that have adjusted for the recent market changes in renewable energy, PacifiCorp's adjustments have overstated the effects of inflation. Recently published studies have shown that cost increases may not be as persistent as PacifiCorp assumes. Lazard's most recent Levelized Cost of Energy Analysis from 2023 provides recent capital cost comparisons for renewable energy technologies based on a detailed analysis of observed new renewable builds across best-in-class renewables companies. This source provides a thoroughly vetted set of actual costs from newly installed projects. [103] Lazard's report states that "Even in the face of inflation and supply chain challenges, the LCOE of best-in-class onshore wind and utility-scale solar has declined at the low-end of our cost range, the reasons for which could catalyze ongoing consolidation across the sector—although the average LCOE has increased for the first time in the history of our studies."[104]

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[95] Renewable Northwest, Round 1 Comments, page 31.

[96] *Ibid.*

[97] *Ibid.*

[98] Renewable Northwest, Round 1 Comments, page 31.

[99] LC 82, PacifiCorp Reply Comments, page 47.

[100] Renewable Northwest, Round 1 Comments, page 32.

[101] *Id,* page 32.

[102] *Id,* page 32.

[103] https://www.lazard.com/media/2ozoovyg/lazards-lcoeplus-april-2023.pdf.

[104] Lazard. Levelized Cost of Energy Analysis-version 16.0. April 2023. Available at: https://www.lazard.com/media/2ozoovyg/lazards-lcoeplus-april-2023.pdf.

Regulators in other states are also assessing the reasonableness of using NREL ATB studies for the purposes of resource planning.[105] One South Carolina study found that relying on NREL ATB was reasonable and anticipates, "…a gradual decline in real-dollar costs due to industry learning curves and economies of scale, especially as renewable adoption accelerates. Therefore, we encourage Santee Cooper to remain open to upward adjustments in future procurement targets to capitalize on these anticipated cost reductions."[106] Staff finds this sentiment to be similarly relevant to PacifiCorp's resource cost methodology and would also encourage the Company to reassess overly conservative costs and monitor the market for anticipated cost reductions.

For example, PacifiCorp estimates a 34 percent increase in the cost for solar starting in 2023 and persisting for five years after, until cost declines in 2029. This results in a projected cost of $1,533/kW for a 200MW PV installation in Utah for 2023 through 2028.[107]

PacifiCorp's capital cost forecast for land-based and offshore wind is also unsupported by the 2023 NREL ATB and Lazard. For 2023 through 2028, PacifiCorp assumes roughly $2,000/kW for land-based wind and $5,900/kW for offshore wind. According to Lazard's 2023 Levelized Cost of Energy Analysis, capital costs for land-based and offshore wind reaches a high of $1,700/kW and $5,000/kW, respectively. [108]

Finally, PacifiCorp's resource storage assumptions are also significantly higher than NREL's projections. PacifiCorp's battery storage capital costs estimates are $454 and $477/kWh in 2022 and 2023 respectively, with no projected cost declines until 2029.[109] NREL 2023 study estimates capital cost of approximately $470/kW but assumes step cost decline afterwards with capital cost reaching a low $320/kW in 2032.

Staff, through its consultant, Synapse, conducted a high-level analysis to estimate the difference in the Preferred Portfolio's build costs if the utility had instead relied on NREL's 2023 ATB. This analysis relies on the current levels of near-term renewable builds presented in the 2023 IRP Preferred Portfolio and does not attempt to re-optimize the renewable builds based on these lower costs. This analysis reflects the situation where PacifiCorp conducts resource planning using elevated prices, and is able to procure renewable resources for lower cost in actuality.

Additionally, we highlight here that if PacifiCorp had incorporated supply-side costs for renewables that were more in line with PGE, CPUC, and NREL ATB, it is likely that PLEXOS LT would select more of these resources ***instead of*** higher-cost alternatives, such as nuclear, non-emitting peakers, and fossil units. It is important to note that the build costs shown in the PLEXOS LT outputs are shown pre-tax credits and without annualization, rate of return, or depreciation. This means that the final impact on the Preferred Portfolio revenue requirement will be different than the total cost delta presented below.

[105] See South Carolina Public Service Commission, Report by PA Consulting *Independent Review of Santee Cooper's 2023 Integrated Resource Plan*. December 2023.
[106] *Ibid.*
[107] PacifiCorp file "(P)-Figure 7.3-7.5 History of IRP Renewables Cost Curves 2023 0119.xlsx".
[108] https://www.lazard.com/media/2ozoovyg/lazards-lcoeplus-april-2023.pdf.
[109] Renewable Northwest, Round 1 Comments, page 38.

Table 9: Renewable Build Costs Summary Results

Category	Resource Type	NPV (2023-2030) ($M)	2023	2024	2025	2026	2027	2028	2029	2030
Capacity (MW)	Solar	n/a	-	-	1,069	2,524	483	1,907	-	-
2023 IRP Build Costs ($)	Solar	$7,037	-	-	$1,687	$4,020	$790	$2,946	-	-
ATB Build Costs ($M)	Solar	$6,034	-	-	$1,474	$3,440	$650	$2,530	-	-
Delta ($M)	Solar	$1,003	-	-	$213	$580	$140	$416	-	-
Capacity (MW)	Wind	n/a	-	43	296	-	100	300	1,900	-
2023 IRP Build Costs ($M)	Wind	$3,317	-	$85	$644	-	$212	$613	$3,394	-
ATB Build Costs ($M)	Wind	$2,427	-	$59	$405	-	$138	$414	$2,631	-
Delta ($M)	Wind	$890	-	$26	$240	-	$75	$199	$763	-
Capacity (MW)	BESS	n/a	-	-	754	2,929	628	1,900	1,149	-
2023 IRP Build Costs ($M)	BESS	$9,594	-	-	$1,364	$5,300	$1,136	$3,416	$2,009	-
ATB Build Costs ($M)	BESS	$8,590	-	-	$1,240	$4,767	$1,010	$3,018	$1,800	-
Delta ($M)	BESS	$1,004	-	-	$124	$533	$126	$398	$209	-
Total Delta ($M)	All	**$2,897**								

Staff Expectation:

- As part of the IRP update and future IRP processes, PacifiCorp should update its renewable cost assumptions based on more recently available information.

Natrium and Non-Emitting Peaking Resources

In Opening Comments, Staff raised concerns about the permitting timeline and fuel availability of nuclear resources in the Company's preferred portfolio.[110] Staff concerns about reactor fueling risks and permitting were shared in comments from the Sierra Club,[111] NewSun,[112] and Renewable Northwest.[113] As an example RNW documented the lengthy six-year timeline to final approval by the NRC of the only other small modular reactor (SMR) design to date, developed by TerraPower competitor NuScale Power Company.[114] RNW follows this discussion with a request for the Company to identify offramps that would provide adequate lead time for replacement of the Natrium facility with clean energy resources with comparable attributes, a request that Staff finds to be reasonable.

[110] LC 82 – Staff's Round 1 Comments, page 44.
[111] LC 82 – Sierra Club's Round 1 Comments, page 58.
[112] LC 82 – NewSun Energy's Round 1 Comments, page 5.
[113] LC 82 – Renewable Northwest's Round 1 Comments, page 21-22.
[114] Id.

In PacifiCorp's December reply comments, the Company stated that its consideration of nuclear resources in the 2023 IRP are consistent with Oregon IRP Guidelines 1(a), 1(b), and 1(c), and therefore those resources are limited to years outside of the action plan and CEP planning windows and require continued evaluation of their potential.[115] The Company further stated that it "cannot provide meaningful tracking and reporting" on the Natrium facility's NRC Construction Permit Application due to there being no commercial agreement with the facility's developer, TerraPower. The Company did provide that a construction permit (CP) is targeted for submission to the Nuclear Regulatory Commission (NRC) by Q1 2024, stating a generic timeframe for issuance of the CP by the NRC is 36 months.[116] Staff, assuming a similar 36-month timeline for issuance of the separate operating license (OL) for the Natrium facility from the NRC, contemplates substantial risk in selecting this resource in the preferred portfolio for inclusion in the year 2030. Staff finds comments from the Sierra Club, NewSun, and RNW regarding fueling cost and risk, permitting timeline risks, and the lack of adequate alternatives should permitting issues arise, to be compelling.

The Company's timelines for the availability of non-emitting peaking resources and nuclear resources have both been modelled for portfolio consideration in the year 2030 or beyond, intentionally outside of the action plan window and the current CEP compliance window.[117] As the Company states that it anticipates that non-emitting peaking resources will improve in performance and cost-effectiveness, Staff believes that the Company should also prepare for the possibility that both non-emitting peaking resources and nuclear resources may potentially fail to materially improve in those regards before the year 2030.[118]

In short, Staff finds that the overly optimistic timeline for both the Natrium nuclear technology and any potential non-emitting peaking technology - given both what is known and unknown - requires planning more reflective of implementation risks. Staff is not opposed to either technology per se and believes they may both be necessary to achieve HB 2021's 2040 target and for the broader region to decarbonize. However, we agree with RNW's observation that the 2021 IRP selection of Natrium in 2028, which was due in part to overly optimistic assumptions, impacted both the action plan and the scope of the subsequent RFP (UM 2193).[119] Staff finds that PacifiCorp appears to be repeating the same process in LC 82 with these long lead time resources. An additional implication of this approach in LC 82 is that it puts Oregon's decarbonization efforts at risk.

Per a December filing, NRC has scheduled a readiness assessment meeting for the TerraPower permit application on January 10, 2024.[120] The process to conduct the assessment will take four weeks and 45 calendar days, following which NRC staff will issue a public report on their findings. The approximate date for the publication of this report will be approximately around March 20, 2024. At the point of the NRC report's publication, the Company should have a clear understanding if the Natrium project is on track to begin construction under the very tight timelines found in LC 82.

In variant portfolio P06 – No Forward Tech, PacifiCorp explored the risk of neither the nuclear facility ***nor*** the non-emitting peaker being operational by the end of 2030. This portfolio showed no impact to

[115] LC 82 – PacifiCorp Reply Comments, page 94-95.
[116] PacifiCorp response to Staff DR No. 118.
[117] LC 82 – PacifiCorp Round Reply Comments, page 93-95.
[118] LC 82, PacifiCorp Reply Comments, page 93.
[119] Renewable Northwest, Opening Comments, page 20.
[120] *See Filing in NRC Docket 99902087, "Preapplication Construction Permit Readiness Assessment Plan," December 20, 2023.*

the timing of the planned retirements of approximately 2.5 GW of coal generation capacity between 2028 and 2032. Instead this variant portfolio showed more some additional solar and wind but most notably an additional 1.2 GW of batteries by 2033. This portfolio had some of the highest emissions compared to all other portfolios.[121]

As RNW notes, the Company's plan to replace SMRs should they not be viable is to largely replace them with non-emitting peakers.[122] The Company states that non-emitting peakers' limited presence in the 2023 IRP preferred portfolio supports the Company's position that the risks associated with these resources are reasonable.[123] Given the potential for neither to emerge and both the higher cost and higher emissions associated with this outcome – as evidenced by P-06 – the Preferred Portfolio's reliance on emergent nuclear and non-emitting peaking resources may prove to be an outsized risk.

Staff would note that in LC 80 the procurement of long lead time (LLT) resources posed a similar set of risks and procurement challenges for PGE. Given the uncertainty around timelines for both nuclear and non-emitting peaking resources, Staff believes that the Company should issue a request for information (RFI) for LLT resources. The RFI should be used to inform placement of LLT emergent resources in a preferred portfolio more realistically by accurately comparing them against more traditional, matured, resources. To gain a more accurate view of the entire resource landscape, the Company's RFI could also study advanced geothermal, pumped hydro storage, transmission costs associated with offshore wind, and any other resources identified by the Company or stakeholders. The Company might even coordinate with PGE in developing this RFI for a streamlined approach.

Staff Recommendation 11. Direct PacifiCorp to update Action Plan Item 1g to reflect actual events since the IRP/CEP was filed in May 2023.

Staff Expectations:

- Inform the Commission in the IRP Update whether the TerraPower permit application passed the U.S. NRC's readiness assessment for Natrium's construction permit and the estimated timeline for the project following that decision.
- In the next IRP, utilize a ten-year buffer between the date of the issuance of the Natrium CP and when that resource may appear in the Company's preferred portfolio.
- In the next CEP, more directly address the high-level planning questions from Order No. 22-446 regarding the critical junctures, dependencies, and barriers to nuclear and any non-emitting peaking technology as part of a preferred portfolio.

Small Scale Renewables

In Opening Comments, Staff expressed an interest in exploring options to facilitate the development and acquisition of small scale renewables (SSRs) in a cost-effective manner, highlighting the RPS certification process in particular.[124]

[121] LC 82, PacifiCorp 2023 IRP, page 268, Table 9.14.
[122] Renewable Northwest, Opening Comments, page 22.
[123] LC 82, PacifiCorp Reply Comments, page 93.
[124] LC 82 – Staff's Opening Comments, page 46.

Staff greatly appreciates the Company's efforts to offer regulatory recommendations toward easing the acquisition of SSRs in its reply comments. Regarding the Company's recommendation that the OPUC amend or waive OAR 860-091-0030(1), Staff finds that this may be an unnecessary solution to a barrier that remains, in Staff's view, to be largely informational. The Company specifically cites an additional ODOE regulation, OAR 330-160-0035(2), that "may require…an explanation of the relationship between the applicant and the WREGIS account holder."[125] Staff does not understand how this requirement, nor RPS certification as a whole, are meaningful barriers to potential SSR project financing.

Staff agrees with the Company's recommendation that incentives might be refined or updated to better reflect system SSR needs through updated PURPA policies in the OPUC's UM 2000 proceeding.[126] Should these policies be updated to better reflect SSR acquisition costs, Staff would urge the Company to utilize PURPA policies to the greatest extent possible to streamline its SSR acquisition process, and additionally facilitate modelling of SSR acquisition in portfolio modelling as the SSR mandate will remain an ongoing compliance obligation. The ability to model SSR acquisition costs reliably and accurately will facilitate the modelling of marginal SSR needs and associated costs when system capacity acquisitions are made.

Resource Adequacy Modeling, Front Office Transactions, and WRAP

In Opening Comments, Staff found that the Company's current resource adequacy and capacity valuation approaches are lacking necessary sophistication and should be updated with both more data and methodologies that better conform to best practices. Staff recommended that the Company incorporate WRAP into its next IRP, update its resource capacity contribution methodology, add more weather data, and perform a Loss of Load Expectation (LOLE) analysis on the preferred portfolio.[2]

RNW has a host of recommendations for the Company to modernize its reliability and resource adequacy modeling that are largely in line with Staff's opening comments. Among them, RNW recommends that the Company move beyond its current capacity factor method to something an Effective Load Carrying Capability (ELCC) method or something similar, such as the "Global Slicing Block" that is available in PLEXOS.[3] RNW also believes that the Company's 13 percent Planning Reserve Margin is unfounded.[4] Of greater concern to them, RNW finds that the Company's deterministic look at Loss-of-load-probability (LOLP) modeling is lacking and recommends that the Company incorporate stochastic parameters for weather risk factors that correlate with supply and demand.[5] Given that the Western Resource Adequacy Program (WRAP) may become binding as early as 2026, RNW also advocates that the integrate WRAP into the IRP process.[6]

The Company responded to comments made by both Staff and RNW in its Round 1 Reply Comments. Staff recommended that the Company update its capacity valuation methodology to incorporate multiple years of weather data, calculate and report the LOLE of the preferred portfolio in each year and explain why the Company chose to plan to its current level of reliability. PacifiCorp agrees with Staff and RNW that incorporating stochastic conditions is a necessary part of identifying supply and demand risks and notes that neither wind nor solar nor energy efficiency savings were modeled stochastically in the 2023 IRP. The Company also agrees that the value of stochastic analysis is higher when multiple years of data are used but also notes that incorporating this is a significant undertaking. The Company states that it looks forward to further improvements to the LOLP and that it is always open to improvements in its RA modeling.[7] In response to Staff's and RNW's

[125] LC 82 – PacifiCorp Reply Comments, page 85.
[126] Id, page 86.

comments on WRAP, the Company states that it is actively evaluating the WRAP program and considering how to implement it in the IRP as early as 2026.[8] The Company did not appear to directly respond to RNW's recommendation to conduct an ELCC style analysis.

Staff recognizes that updating LOLP, capacity valuation, and RA modeling is a large undertaking that may take many months. While Staff continues to advocate for the use of more years of weather, load and generation data, Staff is supportive of these things being included in the Company's next IRP. Staff also agrees with RNW's comments advocating for stochastic modeling of supply and demand variable in LOLP analysis and recommends that wind and solar resources be modeled stochastically using observed weather and load correlation. Staff also agrees with RNW that switching to an ELCC style analysis of capacity valuation is a necessary modeling improvement that should be integrated into the next IRP. Staff reiterates its past recommendation that the Company model and report the LOLE of the preferred portfolio in a future IRP.

Staff continues to recommend that PacifiCorp consider WRAP participation, including potential future obligations and benefits, in the next IRP. Staff notes that another Oregon-regulated utility, Idaho Power, has chosen to model the benefits of WRAP in its current IRP, LC 84, and assumes that WRAP's operational program would provide some system capacity benefit starting in 2027.[127] While Idaho Power presents this merely as a first attempt at modeling WRAP benefits, Staff feels it necessary to point out that one of the Company's Oregon peer utilities has already begun incorporating WRAP into its IRP.

Front Office Transactions

Staff is concerned by the Company's reliance on FOTs in its IRP.[128] PacifiCorp's IRP allows for a certain amount of market purchases to contribute to system capacity needs. These purchases are referred to as Front Office Transactions (FOTs) and they have limits as shown in Table 5.8 in the IRP and reproduced below as Table 10.

Table 10: Reproduction of Table 5.8 of IRP[129]

Market Hub	Availability Limit (MW)				
	2023 IRP			2021 IRP	
	Short-term (2023-2027)	Long-term (2028-2042)		Summer	Winter
		Summer	Winter		
Mid-Columbia (Mid-C)	1979	500	350	500	350
California Oregon Border (COB)	424	0	250	0	250
Nevada Oregon Border (NOB)	200	0	100	0	100
4 Corners (4C)	398	0	0	0	0
Mona	325	0	300	0	300
Total	**3326**	**500**	**1000**	**500**	**1000**

In the IRP, FOTs are modeled as short-term purchases that can be made with little or no notice. However, this may be an oversimplification. Staff also notes that in order to demonstrate compliance with WRAP, an entity has to secure resources and contracts with a lead time of multiple months,

[127] LC 84, Idaho Power IRP Initial Filing, page 8.
[128] LC 82, PacifiCorp 2023 IRP, page 33, Action item 5a.
[129] 2023 IRP at 126.

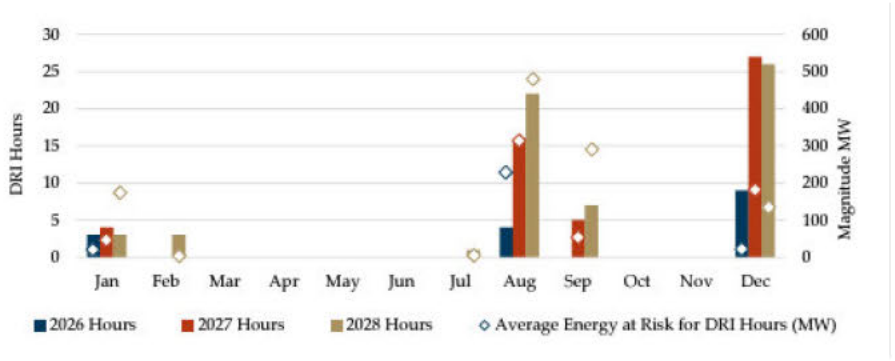
meaning that the Company's choice to rely on short-term purchases may lead to the Company being out of compliance with WRAP's forward showing requirements. Further, given the suspension of the Company's RFP, UM 2193,[130] Staff anticipates that the Company will need to rely further on FOTs to offset resources that may come on later than what was expected at the beginning of LC 82.

In other proceedings, the Company has noted that the volume of transaction in regional wholesale markets has been steadily declining in recent years.[131] The Company models a constant level of FOT availability at its main five market hubs through 2027, which is incongruous with its operational realities of the last few years. Staff worries that the failure to align its action plan assumptions with the operational realities it uses as evidence in its power cost dockets could lead to a situation in which it neither has resources available to meet its load nor a viable counterparty to buy energy in a peak load hour.

Renewable Northwest also expressed concern with PacifiCorp's assumptions regarding future reliance on regional markets. RNW notes that near-term reliance on market purchases for capacity in this IRP is high. In addition, RNW notes that the Load and Resource Balance table in the IRP includes market purchases well above the stated FOT limits in Table 5.8. RNW notes, "regional markets are likely to experience increasing uncertainty in both depth and availability due to environmental policies and regional market initiatives, which increases the importance of hedging against the continued risk of high market reliance in the future." RNW recommends that PacifiCorp work with other regional planning organizations such as the Western Power Pool (WPP) to develop "a detailed, quantitative analysis on the likelihood of regional markets to provide reliable power at non cost-prohibitive prices." Staff acknowledged that a regional study could provide value in long-term planning, but notes that there are currently multiple organizations that already look at resource adequacy to assess whether there is a surplus of energy available in the region. For example, WECC releases frequent studies of regional capacity availability. The 2023 WECC Western Assessment of Resource Adequacy (WARA) finds that total planned resources in the WECC are not adequate to prevent substantial "Demand at Risk" hours in 2026-2028.[132] Demand at risk hours are defined as the number of hours in a year that are at risk for loss of load exceeding the one-day-in-ten-year outage threshold. As Figure 9 below shows, in August 2028, the WARA finds on average about 500 MW of Demand at Risk over 25 hours.[133] We note, however, that shortage predictions five years out can often change, as both demand and supply side resources respond in advance to potential shortfalls with incremental development activity.

Figure 9: Mid-term DRI Hours and Magnitude for the Western Interconnection

[130] See the Company's September 29, 2023 filing in UM 2193.
[131] See UE 420, PAC/400, Mitchell/59 here.
[132] WECC. 2023 Western Assessment of Resource Adequacy, page 17.
[133] WECC. 2023 Western Assessment of Resource Adequacy, page 16.



The WARA finds that a significant increase in Demand at Risk hours in December can be attributed to increased load forecasts in the Northwest, while there are relatively few utility-scale resource additions planned in the Northwest. The WARA concludes that load serving entities may need to delay resource retirements if they cannot mitigate these risky hours in the next two years. However, we note that WARA may have less visibility into local small-scale supply and demand resource activity that could reduce the at-risk hours in those out years.

Notably, PacifiCorp's IRP relies on 944 MW of summer market purchases in 2027 and 493 MW in 2028.[134] Given WECC's showing of regional resource adequacy risk during August in those years (red bars in Figure 4 above), the expectation of nearly 1 GW of market energy being available for purchase during summer peak hours seems potentially risky. Further, PacifiCorp has suspended the 2022AS RFP that would have brought resources online from 2025 through 2027, further increasing the region's resource adequacy risk.

These findings are concerning and indicate that PacifiCorp should look seriously at reducing market reliance in the near term, whether through longer-term contracts or resource procurements. If PacifiCorp continues to plan its system around procuring capacity from the market that may not be available and is forced to delay fossil retirements as a result, the Company could be at risk for failing to meeting its HB 2021 Oregon emissions reductions targets and much higher power costs. To address this, PacifiCorp should consider actions to reducing near-term market reliance in the next IRP.

Staff also expects PacifiCorp to consider how WRAP participation might affect the Company's reliance on FOTs in the next IRP. The WRAP forward showing program will require PacifiCorp to secure enough resources to meet their obligations seven months in advance. Staff's understanding is that this requirement may limit FOTs to transactions that can be secured on that timeline. Staff also expects that information from the WRAP program may bring additional transparency into the depth of regional markets during constrained periods and that this information could help to inform future assumptions regarding FOT availability.

Staff Expectations:
By the next IRP, PacifiCorp should:

- Include more years of weather data in its resource adequacy modeling.
- Change its capacity valuation to an ELCC or ELCC-adjacent methodology that has weather-correlated stochastic modeling.

[134] LC 82, PacifiCorp 2023 IRP, page 325.

- Calculate and report the LOLE of the Preferred Portfolio in each year.
- Model the benefits of WRAP to the Company's system and compliance hurdles in addition to any requirements that arise from the ongoing resource adequacy rulemaking in AR 660.
- Account for the benefits of WRAP in future IRPs if it plans to continue as a WRAP participant.
- Update FOT availability assumptions based on insights from regional analysis and the WRAP program.
- Restrict the modeling of FOTs to contracts that can be obtained seven months ahead of need.

Transmission

Transmission & Storage

In Round 1 Comments, Energy Advocates recommends, "PacifiCorp should expand future CEP/IRP's to look beyond storage co-location near generation sites and to identify substations and transmission lines that can use storage to flatten load peaks and avoid congestion and costly transmission and distribution upgrades."

In Reply Comments, PacifiCorp responded that the 2023 IRP allows standalone storage to be selected at generator and load locations, in addition to co-location near generation sites. PacifiCorp states, "Additionally, storage options that were not part of a cluster study were considered unconstrained by transmission requirements, such that any amount could be placed anywhere on the system."[135]

PacifiCorp also notes that "[t]he specific substation and transmission would be identified in the request for proposals process after the 2023 IRP."[136] We note, however, that PacifiCorp should reconcile this statement with its unambiguous indication in the IRP itself that battery storage resource options are limited to co-location at generation sites.[137]

PacifiCorp's explanation partially addresses Energy Advocates' recommendation, although it does not directly explain how PacifiCorp considers the ability of storage to avoid transmission and distribution upgrades. PacifiCorp applies a Transmission and Distribution deferral credit to DSM resources in the IRP; however, it does not appear that PacifiCorp has used a T&D deferral value for storage in PLEXOS IRP modeling.

In evaluating PacifiCorp's consideration of T&D deferral value, it may be valuable to consider transmission deferral separately from distribution deferral. Regarding transmission, the PLEXOS modeling logic should be able to assess the potential for storage to reduce or defer the need for endogenously selected transmission resources. The model can generally make economic decisions about whether to upgrade the system with storage or to select a major new transmission investment.[138] However, there may be some transmission deferral value that is not considered in the IRP PLEXOS modeling. For transmission system investments that cannot be selected by the model, and are instead hard-coded, the model will not be able to see any opportunities to defer these resources by acquiring storage.

[135] LC 82, PacifiCorp Reply Comments, page 73.
[136] LC 82, PacifiCorp Reply Comments, page 72.
[137] LC 82, PacifiCorp 2023 IRP, Chapter 8, page 233: "Batteries are assumed to **always** be co-located with other resources, enabling them to shift energy…". Emphasis added.
[138] PacifiCorp response to OPUC DR 190.

The IRP generally states that transmission resources are available for endogenous selection.[139,140] However, further clarification from PacifiCorp to verify whether this applies to all or only some planned transmission resources that could be deferred by storage would be valuable. There may be some transmission expenses that can be deferred by strategically located storage but are not included in the PLEXOS model. If these costs are significant, then applying a transmission deferral credit to storage resources in the IRP could be appropriate.

Staff Expectation:

- In the next IRP, develop a transmission deferral credit for storage resources.

Demand Side Management

Staff's Round 1 Comments supported PacifiCorp's plan to include near-term cost-effective EE in the Company's preferred portfolio. The long-term EE modeling however, appeared insufficient. Staff's analysis found that PacifiCorp had not included available and low-cost EE in the preferred portfolio after 2025.[141] Accordingly, Staff requested that PacifiCorp allow optimization of EE in the CEP to inform whether EE could reduce HB 2021 costs allocated to the CEP portfolio. Staff also requested PacifiCorp reoptimize the Max DSM scenario. Additionally, Staff found opportunities to improve PacifiCorp's avoided costs, such as including avoided planning reserve margin costs and considering HB 2021's emissions constraints.[142] Finally, Staff found PacifiCorp's short-term DR acquisition strategy reasonable but recommended additional measures to reduce NPVRR.

In Round 1 Comments CRITFC, CUB, Energy Advocates, and Sierra Club saw room for additional DSM measures in the preferred portfolio. By extension, they questioned whether PacifiCorp's long-term planning recognized the full implications of HB 2021. CRITFC, CUB, and Energy Advocates voiced concerns that the existing cost-effectiveness tests overlooked EE's non-energy values of improved community resiliency and reduced environmental and ratepayer burdens.

In Round 1 Reply Comments PacifiCorp did not allow the Max DSM Scenario to reoptimize the resource selections around the additional EE. PacifiCorp also declined to reoptimize EE in the CEP. According to PacifiCorp, this request was unnecessary because the model had selected an average of 91 percent of potential EE between 2023 to 2030, with few remaining potential EE measures to meet system needs. PacifiCorp further argued there is no statutory or regulatory mechanism requiring the Company to optimize EE for CEP requirements. Similarly, PacifiCorp argued it lacked Commission guidance to include HB 2021's constraints in avoided cost data. PacifiCorp stated that the Company's method is like the traditional concept of "capacity cost" with the added component of renewable energy compliance. PacifiCorp's standard renewable avoided costs reflect the cost of a renewable wind proxy starting in 2026; prices after that date would not include a forward market component. PacifiCorp further explained that calculating the avoided planning reserve margin cost was difficult due to the addition of

[139] LC 82, PacifiCorp 2023 IRP, page 221.
[140] LC 82, PacifiCorp 2023 IRP, page 213.
[141] LC 82, Staff Round 1 Comments, October 15, 2023, page 58, Figure 12.
[142] For example, in using the existing avoided cost method, Staff found the Company overlooked the need to purchase non-emitting resources rather than the least-cost market resources. These comments mirrored Staff's comments to PGE in LC 80. *See In the Matter of Portland General Electric Company's 2023 Clean Energy Plan and Integrated Resource Plan*, Docket No. LC 80, Staff Corrected Opening Comments at pages 27-30 (July 27, 2023).

variable energy resources. Finally, PacifiCorp provided an update on its electrification modeling and agreed to consider DR measures encouraged by Stakeholders.

Staff's review of OPUC DR 80-1 found that the preferred portfolio selected only 80 percent of available EE between 2023 and 2030, which contradicts PacifiCorp's claim of 91 percent.[143] In either case, the model selected EE *without considering HB 2021,* which suggests that the model would select more EE once HB 2021 strategy is considered. Staff requests that the 2024 IRP Update address the discrepancy in EE acquisition and ensure that the model considers HB 2021 compliance in the preferred portfolio.

Further, PacifiCorp's 2023 IRP analysis relied on an Energy Trust potential study which used avoided costs from the 2019 IRP.[144] If the Company's long-term planning were to indicate that greater amounts of efficiency at higher avoided costs would benefit the system, Energy Trust could perform a new potential estimate that would likely result in a higher amount of available efficiency in Oregon. Therefore, Staff concludes that PacifiCorp's least cost, preferred portfolio likely includes more EE from the previously identified potential, plus additional new23 potential that may have been screened out of Energy Trust's potential study.

Given the impactful new requirements of HB 2021, the value of efficiency in Oregon should diverge substantially from the value of efficiency to some other states on PacifiCorp's system. Under Senate Bill 1547 (2016) and codified in ORS 757.054(3)(a), investor-owned utilities are required by law to acquire all cost-effective energy efficiency and demand response prior to acquiring new generating resources.[145] To meet this requirement, new approaches to avoided costs must be explored and Staff expects PacifiCorp to help update the accounting in UM 1893 to reflect current state policy. Staff expects that Oregon-specific avoided cost analysis will be included in PacifiCorp's IRP Update and future IRPs. The acquisition of higher-value Oregon EE in light of HB 2021 requirements, should be part of PacifiCorp's preferred portfolio in both IRP and CEP planning, not relegated to one or the other.

Staff will consider approaches to avoided cost valuation from other regions, such as the method used by New England energy efficiency program administrators.[146] PacifiCorp's current IRP modeling approach for calculating avoided energy costs has similarities with the New England AESC modeling construct and could be improved to better represent Oregon-specific benefits.
Staff reiterates prior recommendations from Round 1 Comments regarding demand response resources. Staff recommends acknowledgement of DR acquisition to 2026, but encourages the Company to consider additional classes of DR as part of the least cost, least risk portfolio in future analysis. Staff again cites the Northwest Power and Conservation Council's 2021 Power Plan recommendations for utilities to pursue frequently deployable, low-cost measures with minimal customer impact, including time-of-use rates and demand voltage reduction.[147] PacifiCorp did not respond to this request in Round

[143] See PacifiCorp response to Staff DR No. 80-1.
[144] Under OAR 860-030-011(2), utilities must provide energy efficiency avoided cost data based on the utility's most recently acknowledged IRP or update, or from the energy utility's most recent general rate case that has been resolved by a final order of the Commission.
[145] ORS 757.054(3)(a), https://oregon.public.law/statutes/ors_757.054.
[146] For every planning period (3 years), the efficiency program administrators sponsor an avoided energy supply components (AESC) study to determine the value of energy efficiency and other demand-side measures. Avoided costs are calculated for each New England state under a hypothetical future in which New England program administrators do not install any new demand side measures in future years.
[147] See 2021 Northwest Power Plan, page 47. https://www.nwcouncil.org/fs/17680/2021powerplan_2022-3.pdf.

1 Reply Comments. Staff expects future IRP analyses will consider these two resources to help manage power costs and reduce emissions.

Staff Recommendation 12. Acknowledge Action Item 4a to acquire cost-effective energy efficiency and demand response resources.

Staff Recommendation 13. Acknowledge updated avoided costs from the 2023 IRP planning and direct PacifiCorp to work with Staff and Stakeholders to update avoided costs for use in UM 1893 considering HB 2021 constraints.

Staff Expectations:

- In the IRP update, PacifiCorp should address the discrepancy in EE acquisition and ensure that HB 2021 compliance is considered in the preferred portfolio.
- In the next IRP, PacifiCorp should model a counterfactual case in which utilities install no new energy efficiency in Oregon in 2025 or later years.
- In the next IRP, PacifiCorp should include the HB 2021 emissions requirement and SSR/CBRE requirement based on the load forecast without new EE.
- In the next IRP, analyze the role of frequently deployable, low-cost DR measures with minimal customer impact, including but not limited to time-of-use rates and demand voltage reduction.

Conclusion

Despite the good work and hard effort of PacifiCorp staff, the decisions to both suspend the 2022 AS RFP **and** push all necessary revisions of LC 82 analysis to the IRP Update mean Staff and stakeholders lack the shared analytic understanding for making many of the needed acknowledgement recommendations required of this IRP/CEP. Until additional analysis is done, and the Preferred Portfolio is revised, many aspects of this IRP and the CEP cannot be acknowledged.

Staff proposes to truncate the LC 82 review process. Staff will file a motion to update the schedule so as to bring the recommendations from these comments forward for acknowledgement at the public meeting on February 20, 2024. Staff will seek a Commission order on those items that it believes can be acknowledged **and** on minimum analytic requirements for the IRP Update. Further, we recommend that the CEP be revised and resubmitted, per Staff's suggestions, with the IRP Update so that it has the potential to be acknowledged.

Dated at Salem, Oregon, this January 24th, 2024.

JP Batmale

JP Batmale
Administrator
Energy Resources and Planning Division

Appendix A: Summary of Recommendations

RFP Suspension
Staff Recommendation 1. Do not acknowledge the IRP action plan elements 2b and 2c, the IRP's preferred portfolio, or the IRP's long-term plan**.**

Staff Recommendation 2. Direct PacifiCorp to seek acknowledgement of a revised Preferred Portfolio and Action Plan in the planned April 2024 IRP Update.

Staff Recommendation 3. Do not acknowledge the LC 82 CEP and direct PacifiCorp to revise and resubmit the CEP with its April 2024 IRP Update.

Action Plan Changes
Staff Recommendation 4. Do not acknowledge Action Plan items 1h and 2a.

CEP Comments:
Community Benefit Indicators
Staff Recommendation 5. Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.

Staff Recommendation 6. Direct PacifiCorp to provide baseline metrics prior to filing its next IRP/CEP Update. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable.

CBRE Resource Potential
Staff Recommendation 7. Direct PacifiCorp to proceed with the CBRE Grant Pilot, contingent on the Company seeking feedback from the CBIAG in Q1 2024.

Community Engagement
Staff Recommendation 8. Direct PacifiCorp to work collaboratively with Staff, stakeholders, peer utilities, and the CBIAGs in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs by December 31, 2024. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable, inclusive of the perspectives of peer utilities and the utilities' CBIAGs.

Resiliency Analysis Framework
Staff Recommendation 9. The SSR RFP incorporates into project selection criteria appropriate elements of the current Resiliency Analysis Framework and the CBRE Pilot be designed to promote resiliency-related factors.

IRP Comments:
Preferred Portfolio Modeling Process

Staff Recommendation 10. Direct PacifiCorp to fix any confirmed analytical errors in the calculation or application of granularity adjustments.

Natrium and Non-Emitting Peaking Resources

Staff Recommendation 11. Direct PacifiCorp to update Action Plan Item 1g to reflect actual events since the IRP/CEP was filed in May 2023.

Demand Side Resources

Staff Recommendation 12. Acknowledge Action Item 4a to acquire cost-effective energy efficiency and demand response resources.

Staff Recommendation 13. Acknowledge updated avoided costs from the 2023 IRP planning and direct PacifiCorp to work with Staff and Stakeholders to update avoided costs for use in UM 1893 considering HB 2021 constraints.

Appendix B: Staff Expectations

State Policy Compliance in IRP Portfolios

- In the next IRP, PacifiCorp should demonstrate that simultaneous compliance with all state-level policies is feasible with the Preferred Portfolio and with the Preferred Portfolio variants tested in the IRP.
- In the next CEP, PacifiCorp should transparently explore and describe constraints that HB 2021 compliance potentially places on allocation.

CEP Compliance Pathways

- PacifiCorp should utilize its 2025 IRP public input workshops to clarify with stakeholders the relationship between MSP, IRP "actions", Oregon's CEP requirements, and Oregon's DEQ compliance methodology and explore improvements such that HB 2021 targets and activities are informative to and reflected in MSP decisions. As part of this process, changes to MSP disclosure rules should be explored to increase transparency.
- To improve an understanding of tradeoffs in the IRP Update and/or as part of the revised CE, the Company should report Oregon-allocated costs and GHG emissions for the top performing IRP portfolios (inclusive of Oregon's SSR requirement) under various allocation pathways and that PacifiCorp.

Coal-to-Gas Conversions

- PacifiCorp should provide analysis around risk of regret for coal to gas conversions in its 2023 IRP Update.
- PacifiCorp remove Action Items 1c and 1d from the action plan because the Company has already taken these actions.

CEP Comments:

Community Benefit Indicators

- In the next IRP/CEP, Staff expects PacifiCorp to:
  - Adopt CBIs representing the community impacts of energy efficiency, local non-GHG emissions from PacifiCorp facilities, and the Company's CBRE actions.
  - Better inform CBIs and methods with input from stakeholders and community.
  - Enhance tribal-focused CBIs.
  - Use CBIs to better reflect the health impacts of EE.
  - Provide portfolio analysis that allows more direct comparison of tradeoffs of different resource strategies e.g., more precisely capture the CBIs of portfolios.
  - Enhance the ability of CBIs to better reflect the resiliency benefits of actions.
  - Incorporate CBIs reflecting community-level impacts of non-GHG emissions, energy efficiency, and the Company's CBRE actions.

CBRE Activities

- Report regularly to the CBIAG on development including concrete and proactive activities PacifiCorp takes to reduce barriers, accelerate deployment, and expand CBRE potential.

CBRE Inclusion in Preferred Portfolio

- In the IRP/CEP update:
  - Include at least 92 MW of CBRE in the preferred portfolio, depending on the current pipeline of existing programs.

- By the next IRP/CEP:
  - Highlight and communicate the relative benefits of CBRE in load pockets.
  - Quantify the costs and benefits of CBRE for meeting HB 2021 guidance to "[e]xamine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy."[148]
  - Identify one or more new, specific CBRE resource opportunities in Oregon and report on findings regarding specific costs and benefits.

CBRE Program Design

- Engage the CBIAG on potential program designs that can scale quickly to meet community and system needs.

Community Engagement

- Staff expects PacifiCorp's CBIAG and CBI activities to better capture and document Environmental Justice community priorities.
- In the next CEP, Staff expects PacifiCorp to better articulate how it is leveraging stakeholder input and deliverables in related dockets and venues to inform CBIs, CBREs, and portfolio decisions.
- PacifiCorp should include the following additions and enhancements to the Feedback Tracker:
  - Organization/entity attribution or affiliation.
  - Flag for whether and where PacifiCorp incorporated the feedback into specific utility planning, actions, resource selection, and project prioritization.
  - Clear description of why feedback was or was not included.
- Staff encourages PacifiCorp to report on its Tribal engagement strategy by December 31 of each year to the CBIAG. The review should include successes, opportunities for improvement, feedback received, a discussion of Tribal CBIs and CEP/DSP project development, and any work to involve Tribal Nations in planning and resource decision-making.
- PacifiCorp to conduct a participant survey on the engagement process before the next IRP/CEP filing. The survey should allow PacifiCorp to measure the effectiveness of the Company's engagement strategy efforts.

Resiliency Analysis Framework

- PacifiCorp should specify how it intends to incorporate CBIAG feedback and other community input into the community-utility resilience scores and risk drivers by March 1, 2024.
- By the next IRP, PacifiCorp should explain how it will use the Resiliency Analysis Framework in IRP and CEP resource planning, project prioritization, and portfolio selection considering HB 2021's requirement that resiliency planning consider costs, consequences, outcomes and benefits.
- Prior to the next CEP, Staff expects the Company to open discussions with stakeholders on the appropriate geographic scope of the Resiliency Analysis Framework; work with Stakeholders to

[148] ORS 469A.415(4)(d).

identify gaps in comprehension of the Resiliency Analysis Framework; and identify the vulnerabilities and complexities of SAIDI/SAIFI/CAIDI data sets and NRI values as a measure of community level impacts. The Company is encouraged to discuss how it can incorporate the lived experiences of communities into the community-resiliency score. The results of these discussions should be included in the next CEP.

- By next CEP, PacifiCorp should be able to articulate further discussions between the Company, the CBIAG, Tribes, and Stakeholders on how NRI values can be tailored or supplemented to reflect specific community concerns and assets and leverage existing Company resilience plans, such as the wildfire mitigation plan in Docket No. UM 2207.
- At a CBIAG meeting before the next CEP and prior to any CBRE Grant Pilot project selection, provide details for how a completed Resiliency Analysis Framework will be used to impact project selection. Staff expects to work with PacifiCorp in helping to craft this presentation and what will be covered.

Acquisition of Federal Incentives

- The IRP Update includes two variant portfolios that directly reflects Sierra Club's suggested analysis around reduced upgrade costs and early retirements using the EIR program.
- PacifiCorp details in the IRP Update the timeline for submitting an EIR application and the scope of the projects it is seeking to be financed through the U.S. Department of Energy Loan Program Office's EIR program.
- PacifiCorp provides a brief update at every IRP public input meeting and every CBIAG meeting leading up to the 2025 IRP that details the Company's activities to apply for federal incentives and detailing any funding secured.

IRP Comments:

Preferred Portfolio Modeling Process

Before the next IRP PacifiCorp should:

- Work with interested participants from the IRP Public Input process to develop and publicly produce a granularity adjustment methodology.
- Increase transparency around reliability adjustments by stating which resources will be eligible to be included as reliability adjustments in the next IRP and how each one will be valued. Further, it should clarify its modeling approach around how to limit the magnitude of the reliability adjustments that it must make.
- Solicit suggestions through the IRP Public Input process and as part of the Draft IRP of variant portfolios.

As part of the next IRP PacifiCorp should:

- Adjust its modeling approach to better capture resource adequacy needs and the capacity contributions of resource options to reduce the need for and magnitude of reliability adjustments to portfolios.
- Reoptimize variant portfolios that add resources to the preferred portfolio unless there is a clearly explained reason to study an un-optimized portfolio of resources.

Coal Strategy

In the next IRP, PacifiCorp should:

- Utilize coal prices for Jim Bridger that are reflective of actual costs from the Long-Term Fuel supply contract.
- Provide a full update on Utah coal supply issues.

Carbon Price Path

In the next IRP/CEP, PacifiCorp should:

- Recreate the chart above for (a) coal and (b) Oregon allocated GHG emissions comparing past IRP forecasts to actuals.
- Provide a sensitivity that calculates Oregon-allocated GHG emissions under the assumption of no carbon prices operationalized in dispatch. This sensitivity should still be based on the Preferred Portfolio, which considers a carbon price in investment decisions.
- Propose a PacifiCorp specific carbon price that layers atop the medium carbon price the Company's annual cost from wildfires as described by CUB.

Candiate Resource Costs

- As part of the IRP update and future IRP processes, PacifiCorp should update its renewable cost assumptions based on more recently available information.

Natrium and Non-Emitting Peaking Resources

- Inform the Commission in the IRP Update whether the TerraPower permit application passed the U.S. NRC's readiness assessment for Natrium's construction permit and the estimated timeline for the project following that decision.
- In the next IRP, utilize a ten-year buffer between the date of the issuance of the Natrium CP and when that resource may appear in the Company's preferred portfolio.
- In the next CEP, more directly address the high-level planning questions from Order No. 22-446 regarding the critical junctures, dependencies, and barriers to nuclear and any non-emitting peaking technology as part of a preferred portfolio.

Resource Adequacy Modeling, Front Office Transactions, and WRAP

By the next IRP, PacifiCorp should:

- Include more years of weather data in its resource adequacy modeling.
- Change its capacity valuation to an ELCC or ELCC-adjacent methodology that has weather-correlated stochastic modeling.
- Calculate and report the LOLE of the Preferred Portfolio in each year.
- Model the benefits of WRAP to the Company's system and compliance hurdles in addition to any requirements that arise from the ongoing resource adequacy rulemaking in AR 660.
- Account for the benefits of WRAP in future IRPs if it plans to continue as a WRAP participant.
- Update FOT availability assumptions based on insights from regional analysis and the WRAP program.
- Restrict the modeling of FOTs to contracts that can be obtained seven months ahead of need.

Transmission

- In the next IRP, develop a transmission deferral credit for storage resources.

Demand Side Resources

- In the IRP update, PacifiCorp should address the discrepancy in EE acquisition and ensure that HB 2021 compliance is considered in the preferred portfolio.
- In the next IRP, PacifiCorp should model a counterfactual case in which utilities install no new energy efficiency in Oregon in 2025 or later years.
- In the next IRP, PacifiCorp should include the HB 2021 emissions requirement and SSR/CBRE requirement based on the load forecast without new EE.
- In the next IRP, analyze the role of frequently deployable, low-cost DR measures with minimal customer impact, including but not limited to time-of-use rates and demand voltage reduction.

PacifiCorp
2024 Oregon Small-Scale Renewable Request for Proposal

Pre-Issuance Bidder Workshop

January 24, 2024







PACIFICORP
POWERING YOUR GREATNESS

2024 Oregon Small Scale Renewable RFP

Logistics

Workshop Date and Time

- Wednesday, January 24, 2024
- 2:00 – 4:00 PM (Pacific Standard Time)

Location

- Microsoft Teams meeting
- Join on your computer or mobile app
- Click here to join the meeting
- Or call in (audio only)
- tel:+15632755003,,979257373# United States, Davenport
- Phone Conference ID: 979 257 373#

2024 Oregon Small Scale Renewable RFP

Agenda

- Purpose/Resource Types
- Eligibility Requirements
- Contract Considerations
- Interconnection and Transmission Requirements
- Proposed RFP Schedule
- Evaluation and Selection Methodology
- Role of Independent Evaluator (IE)
- Next Steps
- Questions and Comments

POWERING YOUR GREATNESS

2024 Oregon Small-Scale Renewable RFP

Purpose of Request for Proposal (RFP)

- To enable PacifiCorp to obtain, by 2030, approximately 490 megawatts (MW) of additional electrical capacity from small-scale renewable energy projects.
- The RFP supports PacifiCorp compliance with Oregon House Bill 2021 (OR HB2021) Section 37 and furthers PacifiCorp's Clean Energy Plan goals.

Energy sources accepted into the 2024 Oregon Small-Scale Renewable RFP must

- **Have a nameplate capacity of at least 3 MW but no greater than 20 MW *and***
- **Generate electricity utilizing one of the following sources:**
  - Wind energy
  - Solar photovoltaic and solar thermal energy
  - Wave, tidal and ocean thermal energy
  - Geothermal energy
  - Hydroelectric energy
  - Biomass that generates thermal energy for a secondary purpose
    - Biomass energy sources larger than 20 MW will be accepted, but only the first 20 MW of the energy source counts toward OR HB2021 requirement.
  - Energy sources listed above will be accepted to the 2024 Oregon Small-Scale Renewable RFP only if they meet the Renewable Portfolio Standard (RPS) criteria outlined in ORS 469A.025.

Note: Information in this presentation is subject to further change until RFP is issued.

2024 Oregon Small-Scale Renewable RFP

Minimum Resource Eligibility Requirements

- Eligible technologies consistent with ORS 469A.025.
- Eligible resources cannot be behind-the-meter, energy storage, microgrids or demand response technologies.
- Minimum 3 MW (ensures Energy Imbalance Market (EIM) eligibility); maximum 20[1] MW (supports Oregon HB2021 compliance).
- Possess Oregon Department of Energy Renewable Portfolio Standard (RPS) certification at time of commercial operation for contract effectiveness.
- Off-system bids not accepted; projects must be planned to interconnect to PacifiCorp transmission or distribution system in Oregon, Washington, California, Idaho, Utah or Wyoming.
- Completed interconnection study, confirming ability to interconnect to PacifiCorp's transmission or distribution system.
  - https://www.oasis.oati.com/ppw/index.html; https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/Transmission_Wall_Map,_E-Size.pdf
- Site control required.
- Commercial Operation Date (COD) by December 31, 2028.
- Comply with co-location/proximity criteria based on Oregon OAR 860-089-0100, applied to a 20 MW threshold level.
- Bids for new and existing resources will be accepted provided the existing resources are not obligated in a contract effective as of the COD date above.
- Bid fee will be required for each bid proposal. Details provided at RFP issuance.
- All PPA bids must be fixed-price for the full term.

[1] As previously noted, Biomass resources larger than 20 MW *will* be considered, but only the first 20 MW will count toward OR HB2021 capacity requirement.

2024 Oregon Small-Scale Renewable RFP

Minimum Eligibility Criteria

1. Receipt of bid by deadline
2. Receipt of bid fee by deadline
3. Completed provided Bid Summary and Pricing Input Sheet, without modification
4. Capacity interconnected to PacifiCorp's transmission or distribution system
5. Completed PacifiCorp Transmission Interconnection Study or signed PacifiCorp Transmission Interconnection Study Agreement
6. Interconnection study results and/or executed Large Generator Interconnection Agreement (LGIA) consistent with and supports bid
7. Demonstrated ability to achieve COD deadline
8. Execute Confidentiality Agreement and allow appropriate disclosures to agents, contractors, regulators, etc.
9. No attempts to influence PacifiCorp
10. Entire bid held firm through Q2 2025
11. No commitments of all or part of bid to another entity
12. Must disclose real parties of interest
13. Compliance with Prohibited Vendors List (see pro forma PPA)
14. Bidder's credit information
15. Ability to meet credit security requirements
16. Non-modifiable standard pro-forma contract
17. Bidder not in bankruptcy proceedings
18. Proposal cover letter signed by authorized officer
19. Renewable Portfolio Standard (RPS) certification from Oregon Department of Energy
20. Performance report and model output including hourly output values; bid resource assumption (12X24 or 8760) includes all planned outages and losses, including planned and maintenance outages and curtailment due to protected species such as bats; third-party provided performance report preferred
21. Adherence to all applicable permits prior to and after construction. If applicable, Seller will also agree to Eagle Take Permit or alternative mitigation measures
22. Ownership of, leasehold interest in, or right to develop site, or valid title to property https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20230823_OATTMaster.pdf
23. Oregon bidder agrees to the contractor labor standards attestation in OR HB2021, Section 26 https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
24. Compliance with OR HB2021 reporting requirements, including contractor diversity reporting requirement https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled

2024 Oregon Small-Scale Renewable RFP

Key Contract Considerations

- **Contract form**. PacifiCorp's pro forma power purchase agreement (PPA) will be provided.
  - Standard-form power purchase agreement (PPA). **The PPA will be standard for all bidders with no individual form modifications permitted.**
  - Seller develops, operates and owns resource; PacifiCorp buys the output for a specific term.
- **Ownership.** PacifiCorp takes ownership of all capacity, energy and associated environmental attributes after delivery to PacifiCorp.
- **Contract pricing**. Fixed pricing for term of contract (flat or on-peak/off-peak).
- **Credit requirements.** Letter of credit or approved parental guarantee will be required.
  - **Project development security**. Seller security is required to support delay damages and/or default damages for failure to reach commercial operation date (COD).
  - **Default security.** Seller security is required to support default damages in the event of breach of contract.
- **Commercial Operation Date delay.** Seller will have up to 365 days to cure a delay in scheduled commercial operation date; delay damages will be assessed.
- **Post-execution Condition Precedent.** Agreement language will ensure PacifiCorp's ability to obtain designated network resource (DNR) transmission service at no additional cost.
- **Annual Performance Guarantee.** Agreement will require annual resource mechanical availability guarantee and threshold percentage.
- **Benchmarks.** To support 2030 OR HB 2021 compliance PacifiCorp may offer benchmark bids.
  - PacifiCorp develops, constructs, owns and operates a bid project.
  - Benchmark bids will be evaluated using methodology consistent with market bid evaluation.

2024 Oregon Small Scale Renewable RFP

Interconnection and Transmission

On-system resources (Off-system resources not accepted)

- PacifiCorp Transmission interconnection studies and agreements should be consistent with the bid proposal's technology, size and commercial operation date. If studies and agreements are not consistent with the proposal, bidder will provide documentation from PacifiCorp Transmission that a material modification to their interconnection documentation is not required.
- Bidders are financially responsible to PacifiCorp Transmission for all interconnection costs as identified in their generator interconnection agreement.
- After a PPA is executed, PacifiCorp's merchant function is responsible for requesting and arranging transmission from the Point of Interconnection (POI) to load.

Acceptable Documentation of Interconnection

- Completed PacifiCorp Transmission Interconnection Study (system impact study and/or facilities study) or signed PacifiCorp Transmission Interconnection Agreement is due when bid is submitted.
- An *Informational* Interconnection Study is NOT sufficient interconnection documentation to be considered eligible for the 2024 SSR RFP.

Questions

- For questions regarding PacifiCorp Transmission's interconnection study process, please visit the PacifiCorp Transmission website and contact Generation Interconnection at: www.pacificorp.com/transmission/transmission-services.html

2024 Oregon Small-Scale Renewable RFP

Equity Questionnaire

Facility proximity to community
Census track in which facility is located
Distance from facility to nearest residential home
Number of residential homes within 1 mile of facility
Number of residential homes within 6 miles of facility
How does this resource serve or otherwise impact vulnerable populations?
Is your facility located in a community afflicted with poverty or high unemployment or that suffers from high emission levels?
Distance to nearest existing generation sources by fuel source within 6 miles of proposed facility;
Will the proposed facility replace/supplant identified generation sources?
If "yes," provide estimated reduction in air pollutants/toxics in the community over life of the project/contract due to the facility (when/how much megawatt-hour ("MWh")/year), and avoided emissions released into the community (within 6 miles of the project).

Population characteristics of community where facility is proposed
To be completed based on census track in which facility is located
Race and ethnicity
White (%)
Black or African American (%)
Amercan Indian and Alaska Native (%)
Asian (%)
Native Hawaiian and Other Pacific Islander (%)
Two or More Races (%)
Hispanic or Latino (%)
Population 25 years and over with no high school diploma
Unaffordable housing
Population five years and older that speak English less than "very well" and "not at all"
Population with income 185% below poverty
Population 16 years and older unemployed

Facility Job Creation
Total hires (number of jobs)
Will there be an apprenticeship or training program?
Will there be a project labor agreement (PLA)?
Will Bidder have a plan for outreach, recruitment and retention of women, minority individuals, veterans and people with disabilities to perform work under the contract?
Projected local hires from nearby communities (number of jobs)
Expected total employment (hires) of fossil fuel construction workers (number of jobs)
Duration of work (months of construction / years of operation)
Total Recordable Incident (TRI) of Bidder
Industry Average TRI for type of business (OSHA)
Bidder agrees to use Veriforce, or equivalent, to report safety
Estimate projected economic benefits to the local economy (direct and indirect) (annual $ from payroll taxes, property taxes, other taxes, services)
Minority-owned businesses (percentage of contractors and subcontractors) Woman-owned businesses (percentage of contractors and subcontractors) Service-disabled veteran-owned businesses (percentage of contractors and subcontractors) LGBT firms (percentage of contractors and subcontractors)
What percent of total work hours does Bidder target to be performed by women, minority individuals, veterans and people with disabilities?

Local Impacts
Is Facility a distributed energy resource?
Duration of construction
Source of water used during construction
Source of water used during operations
Is water a permitted or public source
Site disturbance - amount of disturbed soil during construction
Tree and pollinator seed re-planting after construction

Note: Above questionnaire was requested in the 2022AS RFP.

2024 Oregon Small-Scale Renewable RFP

Proposed RFP Schedule

Event	Date
Pre-issuance bidder workshop	1/24/2024
Independent Evaluator (IE) hired	2/16/2024
RFP issued to market and publicized	3/29/2024
PacifiCorp OATT[1] cluster study window open	4/1/2024
PacifiCorp OATT[1] cluster study window closed	5/16/2024
Bidder workshop No. 1	6/27/2024
Bidder workshop No. 2	TBD (September 2024)
Last day for bidder questions to PacifiCorp and IE	11/1/2024
Cluster study results posted to OASIS	~11/12/2024
Benchmark bid submissions due	11/15/2024
Benchmark final bid financial analysis provided to IE	12/20/2024
Market bid submissions due	12/23/2024
Bid eligibility screening complete	1/17/2025
Market bid evaluations complete	2/14/2025
IE final report	3/17/2025
Potential 2025 SSR RFP	3/28/2025
Contracts finalized and executed	TBD (June 2025)
Guaranteed commercial operations date (COD)	12/31/2028

[1] PacifiCorp's Open Access Transmission Tariff (OATT)

2024 Oregon Small-Scale Renewable RFP

Price Proposal – Bidder Inputs

Each Proposal is required to include a completed Bidder Inputs form, which provides PacifiCorp a "numbers based" overview of the bid offering:

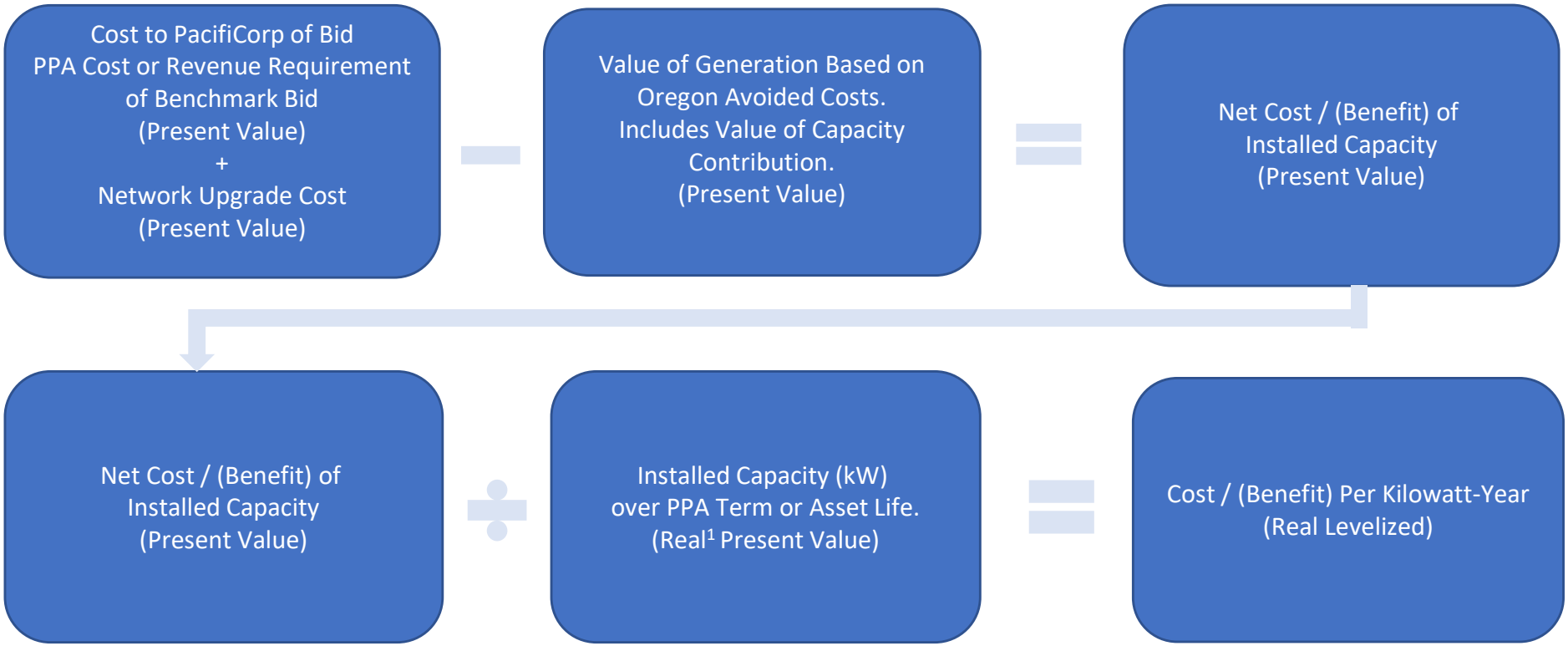
Price Proposal - Bidder Inputs (Required for Bid Submittal)	**Location**
➢ Bid Summary ▪ Type of Bid: PPA or Benchmark ▪ Project Specifics (Generator Type, location, capacity, annual degradation) ▪ Bidder Contact Information ➢ PacifiCorp Interconnection/Transmission Information ▪ Queue Number or Cluster Study ▪ Cost of Interconnection Facilities and Network Upgrades ➢ Purchase Power Agreement Terms ▪ Start/End Dates ▪ $/MWh Price[1] (Flat or On- and Off-Peak Pricing) ➢ Benchmark Terms ▪ Date Operational ▪ Initial Capital Cost (Detail on Tab 3) ▪ ITC/PTC Qualification Questions	Tab 1
Expected First-Year Generation Inclusive of Degradation – 50th Percentile Estimate ➢ 8,760 hourly generation profile, OR ➢ 12 month by 24-hour generation profile ("12X24")	Tab 2a, or Tab 2b
Benchmark Pricing (Not Applicable to Market Bids)	Tab 3
Benchmark Additional Information (Annual Operating and Capital Costs)	Tab 4

[1] Bid prices include direct interconnection costs. PacifiCorp includes network upgrade costs from PacifiCorp Transmission interconnection studies in the financial valuation model.

2024 Oregon Small-Scale Renewable RFP

Evaluation and Ranking of Bids

- Objective is to acquire 490,000 kilowatts (490 MW) of new capacity from small-scale renewable energy projects at the lowest cost to Oregon customers
- Acceptable Bid Criteria:
  - Power purchase agreement and benchmark bids
  - Fixed pricing for Term of PPA (flat or on-peak/off-peak)
- Bids will be ranked based on the LOWEST Real Levelized Cost per Kilowatt of installed Capacity



[1]Discussion of Real Levelized valuation methodology will be provided in June bidder workshop.

2024 Oregon Small-Scale Renewable RFP

Role of the Independent Evaluator (IE)

PacifiCorp is seeking the services of an Independent Evaluator to provide independent validation that:

- PacifiCorp's screening of eligible bidders based on published minimum eligibility requirements was consistently applied to all submitted market and benchmark bids; and
- PacifiCorp's cost valuation of all submitted market and benchmark bids was consistently applied.

2024 Oregon Small-Scale Renewable RFP

Next Steps

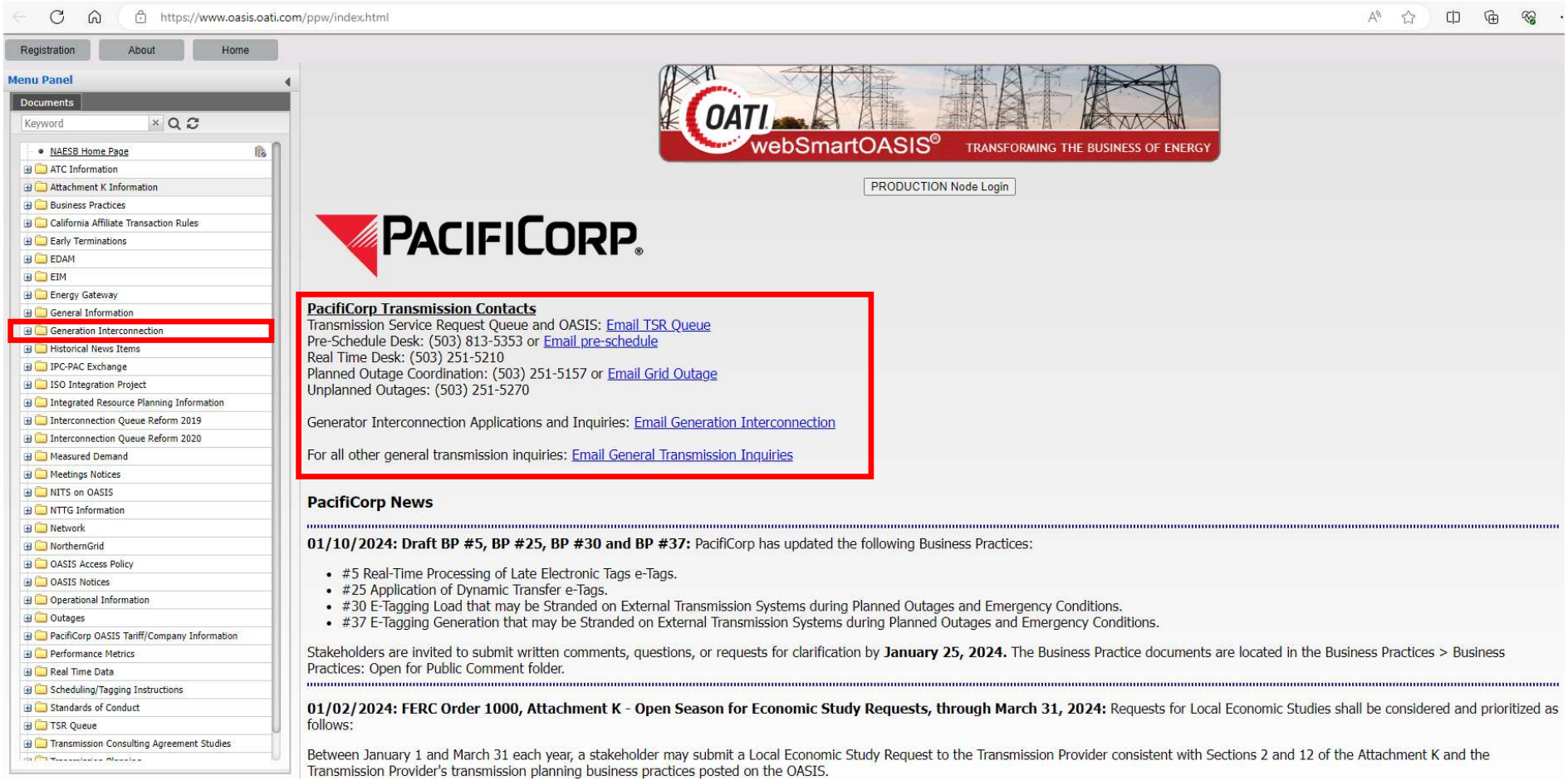
1. Questions or comments regarding this pre-issuance bidder conference should be sent to the following mailbox, even if an answer was provided verbally in today's meeting, to ensure all bidders receive responses: **2024SSR_RFP@pacificorp.com.**
2. Responses to questions (Q&As) received will be posted anonymously on PacifiCorp's 2024 Small-Scale RFP website.
3. 2024 Small-Scale RFP information will be provided it is developed and Q&As will be posted to: www.pacificorp.com/suppliers/rfps/2024-small-scale-renewable-rfp.html.

Supporting Materials

2024 Oregon Small-Scale Renewable RFP

PacifiCorp Transmission OASIS Interconnection Requests

Information on new generator interconnection requests and general interconnection and cluster study information please visit:
https://www.oasis.oati.com/ppw/index.html



Question & Comments



To: PacifiCorp SSR RFP Team (2024SSR_RFP@pacificorp.com)
Subject: Oregon PUC Staff Initial Comments on SSR RFP

PUC Staff appreciates PacifiCorp releasing a draft of the Small Scale Renewable request for proposal (SSR RFP) for comments and the speed with which the Company is pursuing these resources. Staff's comments are organized around two themes. First, PacifiCorp's chosen SSR project characteristics are too narrow, leaving value on the table, driving up project costs, and failing to leverage the RFP as a market discovery mechanism. Second, Staff has suggestions for the structure of the RFP itself, based on our experience, that should help the Company meet its goals and the goals of the state while also assisting potential bidders.

Project Characteristics

Issue: Energy storage ineligibility
Staff position: Energy storage paired with renewable energy projects should be eligible.
Staff rationale:

- Allowing for the pairing of energy storage with renewables and dispatched as a single project enhances capacity value of SSR projects to system peak. Barring energy storage from SSRs appears to make projects less economic than other renewable systems and potentially drives up total costs of CEP compliance for Oregon ratepayers.
    - Energy storage allows for renewable projects to be dispatched in a way that better aligns with system need and to offset fossil fuel use (i.e., summer peak, after 6pm).
- PAC has outstanding capacity need that SSR projects with energy storage can help meet. Evidence:
    - Per the 2023 IRP, the Company has a 2028 summer capacity deficit over 6,000 MW.[1]
    - Per the Draft IRP Update, peak capacity will grow at an average annual rate of 1.7%.[2]
    - Company is seeking 100s of MW of energy storage by 2026 through bilateral contracts in wake of UM 2193 RFP suspension.

Given the outstanding capacity need, Staff questions why PacifiCorp would limit dispatchable load.

- PacifiCorp staff stated on the January 24, 2024 conference call that the Company had determined that the economics of SSR projects with energy storage would be uncompetitive. There is no data to substantiate this argument. Further, the purpose of an RFP is to discover what is available in the market. If project bids are uneconomic due to inclusion of energy storage that should be apparent in their RFP score.
    - Based on PacifiCorp's evaluation and ranking of bids, projects paired with storage will most likely provide more value and thus provide a higher benefit to ratepayers.
- CAISO and WREGIS allow for renewable projects to be paired with energy storage and to be dispatched as a single system.
- ODOE certifies RPS projects paired with energy storage.

[1] LC 82, PacifiCorp IRP, May 31, 2023, pgs. 165 – 172, specifically Table 6.11 and Figure 6.4.
[2] LC 82, Draft IRP Update, January 31, 2024, pg. 2.

Issue: 3 MW floor
Staff position: Allow for project sizes down to 25 kW.
Staff rationale:

- 25 kW is smallest size for Community Solar Program. A lower bid threshold allows for projects such as those waitlisted in the CSP to participate in the SSR RFP.
- Based on the size of PacifiCorp's CSP queue there are clearly many projects less than 3 MW in size that could submit viable bids.
- Function of an RFP is to discover what is available in the market. If project bids are uneconomic due to their smaller size, that will be apparent in the RFP scoring.
- WREGIS allows for renewable projects of any size to be registered.

Issue: CAISO EIM eligibility
Staff position: Should be optional for projects, not a requirement.
Staff rationale:

- Eliminates the potential for smaller projects.
- Imposes unnecessary costs on all projects.
- Reinforces need to allow batteries to be paired with projects as it would increase value of projects to ratepayers.

Issue: Required ODOE RPS Certification at time of commercial operation date (COD)
Staff position: Should be required only after COD and should be optional for projects, not a requirement.
Staff rationale:

- Timing is off. ODOE does not issue RPS certifications until after COD.
- Project does not need ODOE certification to be considered renewable energy resource. Just needs to be one of the technologies listed in ORS 469A.025. Imposes unnecessary costs on all projects.
- ODOE RPS certification requires WREGIS issuing a generating unit id. This requires equipment that is expensive for smaller projects. It also requires more time and raises project costs.
    - The largest benefit to registering with WREGIS is the ability to generate RECs. As HB 2021 does not require REC retirement to demonstrate emission reductions – and as PacifiCorp will have over 50 million RECs in excess of its Oregon RPS needs by 2030[3] – Staff finds little to no value in requiring PAC SSRs to be WREGIS certified, even if the ODOE RPS verification is waived.

Issue: Contract pricing limited to flat or on-peak/off-peak.
Staff position: Contract pricing should include flat, on-peak/off-peak, or premium peak hours
Staff rationale:

- Projects with associated storage should have a contract pricing structure which incentivizes and rewards its dispatchable nature. More targeted hours will maximize the capacity value derived from these projects at little to no cost to the project.
- Hour derivation could be based on projected market prices or utility capacity needs.
- Structure could follow UM 1729 Solar+Storage rate with minor modifications.

[3] LC 82, PacifiCorp IRP, May 31, 2023, pg. 321, Figure 9.59.

RFP Structure Issue

Issue: Lack of non-price scoring.
Staff position: Include non-price scoring that captures information about benefits to Oregon communities.
Staff rationale:

- Staff appreciates the inclusion of the Equity Questionnaire from the 2022 AS RFP. However, the equity questionnaire is not mandatory in the SSR RFP and answers do not impact project selection.
- Elements should be improved *(see below)* and converted into non-price scoring or sensitivity that captures community benefits.
- The Commission stated that it will want information about direct benefits to communities in Oregon.[4] In fact, capturing more information about benefits and impacts to Oregon communities was identified as a necessary first step in impacting near-term decisions around utility procurement.[5]
- PacifiCorp and Oregon PUC staff agree that many projects could easily qualify as both SSR and as Community Based Renewable Energy (CBRE) projects, under HB 2021.

Issue: Equity questionnaire
Staff position: Equity questionnaire needs more explicit linkages to PacifiCorp's CBIs and reflect input from the Company's CBIAG.
Staff rationale:

- Staff appreciates the inclusion of the 2022 AS RFP Equity Questionnaire. However, the equity questionnaire does not necessarily reflect the Company's evolving CBIs from LC 82 and input from community members in both LC 82 and in the CBIAG.
- Some portion of the equity questionnaire should become the non-price scoring element to the RFP. *(See above.)*
    - These can reflect the Company's evolving CBIs and/or attempt to capture insights into elements like positive impacts to community resiliency or the offsetting of fossil fuels.
    - HB 2021 requires consideration of community benefits in meeting the emissions reduction targets, vis-à-vis offsetting fossil fuels, increasing community resiliency, and even economic development.[6]

Issue: Lack of locational value in evaluating and ranking of bids.
Staff position: PacifiCorp's evaluation and ranking of bids needs to explicitly take into account the locational value of capacity and energy from proposed SSR projects when assessing bids.
Staff rationale:

- Given that PacifiCorp has multiple load pockets across its system (e.g., five in Oregon) and uneven growth across its system (e.g., northeast Oregon load will grow incredibly fast over the next five years), the methodology to determine net cost/benefit of installed capacity needs to explicitly account for locational value.

[4] UM 2273, Order No. 24-002, January 3, 2024, pg. 23
[5] *Ibid.* Pg. 24-25.
[6] ORS 469A.400(2)(a),(b) and 469A.415(4)(d)

- This will encourage the selection of bids with the lowest realized cost to Oregon ratepayers while better capturing the value to the PacifiCorp system.

Issue: No contract negotiations or redlines
Staff position: Redlines should be allowed.
Staff rationale:

- In UM 2274, contract redlines will be used by IE to illuminate bid nuances and pricing so as to make project selection more transparent and so the IE can comment around tradeoffs or irregularities in ISL or FSL project selection. [7]
- Contract redlines allows for projects with more unique attributes to potentially offer lower cost bids and provide necessary flexibility.

Issue: IE Scope
Staff position: Include information that compares and contrasts IE scope and staff interaction in the SSR RFP to UM 2193.
Staff rationale:

- Staff appreciates the inclusion of an IE for this RFP but needs a clearer understanding of the IE's scope and ability to interact independently with stakeholders, and how similar the role will be to an IE selected for a procurement under Oregon's competitive bidding rules.
- Will the IE be responsible for responding to bidder questions?
- Will the IE be responsible for establishing the scoring rules, as well as scoring all, or a subset of bids?
- Will the IE be working for/reporting to PAC or OPUC staff?

Issue: Separation of PacifiCorp RFP and Benchmark staff in establishing scoring system, reviewing bids and contract negotiations.
Staff position: The final RFP needs to clearly state how PacifiCorp RFP and Benchmark staff will be entirely screened from one another throughout this RFP process. This includes naming all employees working as part of the RFP team or the Benchmark team, including their roles and associated dates of their work; ensuring Benchmark staff have had no access to 3rd party project information during this RFP and for at least two years after bids are submitted; and developing and enforcing separation protocols to ensure no confidentiality breech or anti-competitive use of confidential data.
Staff rationale:

- If PacifiCorp's SSR benchmark project development team has any access to RFP bidder information they will have an unfair advantage in their bids.
- All other RFPs require a separation of staff.
- It is standard practice in Oregon to name utility staff on RFP and Benchmark teams so the IE, Staff, and/or stakeholders can verify that a separation between RFP and Benchmark teams was maintained.
- Bidders who receive confidential utility information are embargoed from using it for two to five years after an RFP. The same should be true for utility staff.

[7] UM 2274, Order No 24-011 at 1.

In closing, an RFP functions as a market discovery mechanism. In Staff's experience, an RFP with too many restrictions on project eligibility limits the Company's and stakeholder's insights into available, competitive options. And for this RFP, Staff finds no downside to removing many restrictions (e.g., energy storage, RPS certification, size limit, two-types of pricing, etc.,) if project selection still rests mainly on price and the determination of value as proposed in the RFP's evaluation and ranking methodology. If acquiring 490 MW by 2030 is truly an "all hands on deck" moment, restricting participation – as this RFP currently does – would appear to be counterproductive.

Further, HB 2021's direction to consider community benefits by understanding what they are necessitates some evaluation of a bid's community benefits and impacts. However, the equity questionnaire does not reflect recent developments and is not mandatory. Without some sort of non-price scoring or sensitivity that attempts to capture/understand community benefits we lose a unique opportunity in this RFP to understand and learn while also undermining a key rationale for including SSRs in HB 2021.

Finally, Staff encourages the utility to adopt the changes proposed above and to make any additional improvements necessary to clarify the community benefits and impacts of SSR procurement and ensure a fair, competitive process that reflects HB 2021's evolving approach to the public interest, especially with regards to technical and economic feasibility. Such efforts will be necessary for the Commission to evaluate the prudence of any acquisition and to evaluate the steps PacifiCorp is making to demonstrate continual progress towards the HB 2021 reduction targets at reasonable costs to customers.

ITEM NO. RA1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: MARCH 5, 2024

REGULAR X CONSENT ____ EFFECTIVE DATE N/A

DATE: March 1, 2024

TO: Public Utility Commission

FROM: JP Batmale

SUBJECT: PACIFICORP:
(Docket No. LC 82)
Acknowledgement of 2023 Integrated Resource Plan and Clean Energy Plan.

STAFF RECOMMENDATION:

Acknowledge in part and not acknowledge in part PacifiCorp's (Company) 2023 Integrated Resource Plan (IRP). Decline to acknowledge the Clean Energy Plan (CEP) filed with the 2023 IRP. Adopt Staff's recommendations for additional direction to PacifiCorp as outlined in this memo.

DISCUSSION:

Issue

Whether the Public Utility Commission of Oregon (PUC or Commission) should acknowledge PacifiCorp's IRP with or without conditions, acknowledge specific portions of the IRP, with or without conditions, or decline to acknowledge the IRP.

Whether the Commission should acknowledge PacifiCorp's CEP or decline to acknowledge the CEP.

Whether the Commission should adopt Staff's recommendations for additional direction to PacifiCorp.

Applicable Law

See Staff's February 20, 2024 public meeting memo for a full description of the Applicable Law to this docket.

Analysis

Purpose of Memo
The memo provides a final set of Staff recommendations to aid in Commissioner deliberation at the March 5, 2024 public meeting. These final recommendations are informed by the February 20, 2024 public meeting, the discussion of the Commissioners in that meeting, and subsequent review of the issues. For more background information behind these recommendations, please see Staff's previous public meeting memo, filed February 7, 2024, and associated comments from Stakeholders and PacifiCorp.

The approach guiding Staff's final suggested recommendations for Commissioner consideration are as follows:

- Elements of the IRP can be acknowledged in part.
- Based on Staff's interpretation of statute, the CEP cannot be acknowledged – in whole or in part – due to the CEP's failure to meet the standard in ORS 469A.420 to be in the public interest and consistent with the emissions reduction targets.
- Based on comments made by PacifiCorp at the February 20, 2024 public meeting, the April 2024 IRP/CEP Update is not a viable vehicle for any substantial new or revised analysis.
- All recommendations for any new or revised IRP/CEP analysis should focus on the 2025 IRP/CEP, which PacifiCorp plans to file in April 2025, and are based on an expectation that that IRP/CEP will be timely filed.
- Recommendations for the 2025 IRP/CEP should be kept to a minimum. The focus is on identifying the least number of analytic improvements or qualitative additions necessary to develop an IRP/CEP that leads to an acknowledgeable CEP.
- Additional recommendations are not new to this proceeding, but instead are drawn from previously stated expectations or stakeholder comments. Staff will continue to work with the Company and Stakeholders in the lead up to the 2025 IRP/CEP to implement the expectations identified in Staff's Round 2 comments.

Staff's final, suggested recommendations for Commissioner consideration are organized into two parts:

1. **Original Recommendations**: These come from Staff's Round 2 Comments. They are also included as Attachment A to Staff's February 20, 2024 public meeting memo. The recommendations include suggested strike throughs.

2. **Additional Recommendations**: There are three sources for these new recommendations. The first is Staff's stated expectations. The second is utility and stakeholder final comments and/or suggestions at the February 20, 2024 Public Meeting. The final source is the PacifiCorp IRP/CEP.

Original Recommendations
Table 1 below details Staff's original thirteen recommendations and includes Staff's suggested redlines as of the date of this memo.

Table 1, Revised Original Recommendations from Staff

Recommendation Description	Suggested Commissioner Action on March 5
# 1: Do not acknowledge the IRP action plan elements 2b and 2c, the IRP's preferred portfolio, or the IRP's long-term plan.	Retain in full.
~~#2: Direct PacifiCorp to seek acknowledgement of a revised Preferred Portfolio and Action Plan in the planned April 2024 IRP Update.~~	Remove in full
#3: Do not acknowledge the LC 82 CEP ~~and direct PacifiCorp to revise and resubmit the CEP with its April 2024 IRP Update~~.	Change.
#4: Do not acknowledge Action Plan item~~s 1h and~~ 2a.	Change.
#5: Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.	Retain in full.
#6: Direct PacifiCorp to provide specific baseline metrics ~~prior to filing its next~~ in the 2025 IRP/CEP to allow for measured progress towards CBI goals. ~~If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable.~~	Change.

Recommendation Description	Suggested Commissioner Action on March 5
#7: Direct PacifiCorp to proceed with the CBRE Grant Pilot, contingent on the Company seeking feedback from the CBIAG and environmental justice groups~~.in Q1 2024~~	Change.
#8: Direct PacifiCorp to work collaboratively with Staff, stakeholders, peer utilities, environmental justice groups, and the CBIAGs in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs by December 31, 2024. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable, inclusive of the perspectives of peer utilities and the utilities' CBIAGs.	Change.
#9: The SSR RFP incorporates into project selection criteria appropriate elements of the current Resiliency Analysis Framework and the CBRE Pilot be designed to promote resiliency-related factors.	Retain in full.
~~#10: Direct PacifiCorp to fix any confirmed analytical errors in the calculation or application of granularity adjustments.~~	Remove in full. *Staff will have more specific directions in next table.*
#10 (Formerly #11): ~~Direct PacifiCorp to update Action Plan Item 1g (Natrium) to reflect actual events since the IRP/CEP was filed in May 2023.~~ In the 2025 IRP/CEP, direct PacifiCorp to update Natrium assumptions to reflect actual events.	Revise.
#11 (Formerly #12): Acknowledge Action Item 4a to acquire cost-effective energy efficiency and demand response resources.	Retain in full.
#12 (Formerly #13): Acknowledge updated avoided costs from the 2023 IRP planning and direct PacifiCorp to work with Staff and Stakeholders to update avoided costs for use in UM 1893 considering HB 2021 constraints.	Retain in full.

Additional Recommendations

Table 2 below details additional recommendations Staff believes the Commissioners should consider in the acknowledgement order. Recommendations number 13 and 14 are recommendations that should have been included with the original thirteen but were

not due to a Staff oversight. We apologize for the error and seek to correct that by including those recommendations below.

The other seven remaining recommendations are all forward looking. They are designed to help the PacifiCorp IRP team by providing clear expectations for the 2025 IRP/CEP.

The table below also includes the source of the recommendation and a short summary of the rationale behind the recommendation's inclusion. While the text may not exactly match a recommendation attributed to a stakeholder, Staff sought to capture the essence of the recommendation. Finally, many stakeholders made outstanding contributions to this IRP/CEP in written and verbal comments, which Staff greatly appreciates. Staff apologizes in advance for any potential oversights in recognizing the contribution of a stakeholder organization toward these additional recommendations.

Table 2, Additional Recommendations

New Recommendation Description	Source and Rationale
#13: Do Not Acknowledge Action Items 1c and 1d from the action plan because the Company has already taken these actions.	**Source**: Staff expectations. **Rationale**: Should have been included in original recommendation. Do not acknowledge action items already undertaken and not already acknowledged.
#14: Acknowledge Action Plan Items 3a through 3e, 5a, 6a, and 6b.	**Source**: PacifiCorp IRP Action Plan. **Rationale**: Should have been included in original recommendation.

New Recommendation Description	Source and Rationale
# 15: In the 2025 IRP/CEP model, PacifiCorp must: (1) demonstrate that simultaneous compliance with all state-level policies is feasible with the least-cost, least-risk Preferred Portfolio and with the Preferred Portfolio variants tested in the IRP under multiple allocation paradigms; (2) include expected CBREs in the Preferred Portfolio and ensure that the Preferred Portfolio meets Oregon's Small Scale Renewable Requirement; (3) adopt best practices in resource adequacy modeling, including consideration of load and resource performance under multiple weather years and calculation of loss of load expectation and capacity contributions using probabilistic analysis.	**Source**: Staff's expectations; CUB, Sierra Club, and RNW comments. **Rationale:** An optimized preferred portfolio that reflects law and best practices.
#16: In the 2025 IRP/CEP, PacifiCorp shall include an analysis of forecasted costs and annual emissions of the Preferred Portfolio using only actual carbon prices in effect in 2025 through the 20-year planning horizon.	**Source**: CUB comments. **Rationale**: Better forecast of actual emissions. Provides insight into the potential continuation of historical underperformance of the fleet's emission reductions relative to IRP forecasts.
#17: In the 2025 IRP/CEP, PacifiCorp shall calculate and report the costs and GHG emissions associated with each portfolio assuming that GHG prices are not reflected in dispatch decisions but still included in investment and retirement decisions.	**Source**: Staff expectations. **Rationale**: Improve understanding of tradeoffs in CEP construction.
#18: In the 2025 IRP/CEP PacifiCorp shall provide an explanation of renewable cost assumptions and a comparison to recent pricing information from such organizations as National Renewable Energy Lab and Lazard.	**Source:** RNW comments **Rationale:** Improve transparency of resource costs in portfolio development.

New Recommendation Description	Source and Rationale
#19: In the 2025 IRP/CEP, PacifiCorp shall confirm that coal generator cost assumptions reasonably reflect the structure and terms of any associated fuel supply agreements or fuel supply plans. Categorize variable costs that affect dispatch as variable costs in the model with as much accuracy as reasonably possible.	**Source:** Sierra Club **Rationale:** Improved transparency in pricing of coal resources.
#20: In the 2025 IRP/CEP PacifiCorp shall report on steps that the Company took to reduce the magnitude of reliability and granularity adjustments, how the Company engaged with stakeholders on adjustments, and describe the methodology and report the resulting reliability and granularity adjustments by resource. Include any supporting work papers demonstrating the granularity/reliability adjustments in the Data Disk.	**Source:** Sierra Club, RNW, and Staff **Rationale:** Improve modeling and portfolio transparency.
#21: In the 2025 IRP/CEP PacifiCorp shall provide an update on PacifiCorp's efforts to secure Energy Infrastructure Reinvestment (EIR) financing from the DOE Loan Program Office. Assume EIR financing through the DOE Loan Program Office in the Preferred Portfolio or include a variant portfolio that optimizes resource additions and retirements under the assumption of EIR financing.	**Source:** Sierra Club **Rationale:** Very low-cost financing for renewables should be pursued. Future resources – for either the System or for Oregon ratepayers – will be less costly due to EIR financing.

Conclusion

The twenty-two final proposed recommendations above are designed to aid in Commissioner deliberation at the March 5, 2024 public meeting. The memo includes updated recommendations from Staff's previous memo ***and*** updated recommendations based on various sources and in response to learnings from the February 20, 2024 public meeting.

PROPOSED COMMISSION MOTION:

Acknowledge in part and not acknowledge in part PacifiCorp's 2023 IRP, per Staff's recommendations. Decline to acknowledge PacifiCorp's CEP. Adopt Staff's recommendations for additional direction to PacifiCorp as outlined in this memo.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

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

Exhibit 2-129:
Utah PSC on Pac 2023 IRP

- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

PacifiCorp's 2023 Integrated Resource Plan	DOCKET NO. 23-035-10 ORDER

ISSUED: April 17, 2024

SHORT TITLE

PacifiCorp's 2023 Integrated Resource Plan

SYNOPSIS

We acknowledge that PacifiCorp's 2023 Integrated Resource Plan ("2023 IRP") substantially complies with the IRP Standards and Guidelines, with certain important exceptions. Most notably, PacifiCorp's inconsistent and disparate evaluation of the Natrium Demonstration Project ("Natrium"), non-emitting (hydrogen) resource technologies, Carbon Capture, Usage, and Storage ("CCUS") technologies, and new natural gas resources produced a preferred portfolio that likely does not identify the least-cost, least-risk resources. Consequently, we decline to acknowledge the portfolio selection process, the P-MM Preferred Portfolio, and the Action Plan.

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I. INTRODUCTION AND PROCEDURAL HISTORY

On May 31, 2023,[1] PacifiCorp filed with the Public Service Commission (PSC) its seventeenth Integrated Resource Plan ("2023 IRP"), pursuant to the IRP Standards and Guidelines ("Guidelines") adopted in Docket No. 90-2035-01.[2] PacifiCorp requests the PSC acknowledge the 2023 IRP in accordance with PSC rules and fully support the 2023 IRP conclusions, including the proposed action plan ("Action Plan").

The Division of Public Utilities (DPU) and the Office of Consumer Services (OCS) participated in the docket and the following parties intervened: the Utah Association of Energy Users (UAE), Utah Clean Energy (UCE), Western Resource Advocates (WRA), the Interwest Energy Alliance ("Interwest"), Sierra Club, Fervo Energy Company, and Utah Citizens Advocating Renewable Energy.

[1] On March 28, 2023, the PSC granted PacifiCorp's Request for a two-month extension and preliminary comment phase to file its final 2023 IRP due to changed model inputs that were driven by then-recent material changes, including the Ozone Transport Rule (the "OTR"), the Inflation Reduction Act ("IRA"), resource interconnection rules, the Oregon Clean Energy Plan, and Washington's Clean Energy Transformation Act. According to PacifiCorp, the changes required additional time to implement the accuracy of the model's outputs and did not allow stakeholders to review the model's results, including the Preferred Portfolio, before the 2023 IRP March 31, 2023 deadline. The PSC authorized a preliminary IRP and comment phase to accommodate the filing of a preliminary 2023 IRP on March 31, 2023 (PacifiCorp's submission was filed after business hours on Friday, March 31, 2023 and therefore it was submitted April 3, 2023), comments on the preliminary IRP by April 30, 2023, and the final 2023 IRP filing by May 31, 2023.

[2] *See In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp*, (Report and Order on Standards and Guidelines, issued June 18, 1992), Docket No. 90-2035-01. Future references to Guidelines contained in that order will be referred to by the Guideline number. For example, "Guideline 3" will refer to Guideline 3 from page 19 of that order, without referencing the 1992 order each time the Guideline is referred to in this order.

By December 12, 2023, the following parties filed comments: DPU, OCS, UAE, WRA, Interwest, Sierra Club, and UCE. On January 31, 2024, PacifiCorp, DPU, UCE, and WRA filed reply comments.

A. Summary of the 2023 Integrated Resource Plan

The 2023 IRP presents PacifiCorp's plan to supply energy and capacity to provide for and manage the growing electricity demand in its six-state service territory over the next 20 years. The report identifies PacifiCorp's preferred least-cost, least-risk plan ("Preferred Portfolio") to invest in a portfolio of power plants, transmission facilities, firm power purchases, and demand side management (DSM) resources, including energy efficiency and direct load control. The 2023 IRP identifies the type, timing, and magnitude of resource additions and provides a short-term Action Plan.

The 2023 IRP includes modeling advancements such as a Targeted Portfolio Reliability Analysis that allows the assessment of the reliability of resource portfolios by performing subsequent modeling of renewable resources that are selected in the portfolios that can identify capacity shortfalls. It also includes supplemental studies such as, among others, an energy storage potential evaluation that provides details on energy storage grid services and how they can be configured and sited to maximize benefits.

PacifiCorp selected its Preferred Portfolio,[3] which it asserts is the least-cost plan, adjusting for risk and uncertainty. To serve system-wide peak hour demand over the next 20 years, the Preferred Portfolio identifies cumulative supply additions (both long- and short-term resources) of 1,240 MW of non-emitting peaker resources, 9,113 MW of new wind resources, 7,855 MW of new utility solar resources, approximately 8,260 MW of battery storage, inclusive of 350 MW of long duration battery storage, 4,953 MW of incremental energy efficiency, 929 MW of new direct load control resources, 35 MW of pumped hydro storage, 1,500 MW of nuclear, and, through the 20-year horizon, approximately 390 MW of summer and winter firm power purchases, also referred to as front office transactions (FOT).[4]

The 2023 IRP Preferred Portfolio includes the end-of-life retirement of 1,141 MW of existing coal resources, the retirement of 2,335 MW of coal-fueled capacity with selective noncatalytic reduction retrofits, the transition of 1,770 MW of coal resources to other types of fuel, the end-of-life retirement of 595 MW of natural gas resources, the retirement of 23 MW of non-thermal resources, and the expiration of 22 MW of other resources.

The Preferred Portfolio and Action Plan include the retirement of co-owned coal units, the conversion of several coal units to natural gas, the closure of the Naughton South Ash pond, the development of Natrium, new resource acquisitions

[3] *See* 2023 IRP, Volume I, at 307-324.
[4] *See id.*, Table 9.31 at 325.

through the 2022 and 2024 All Source Requests for Proposals, as well as continuing development and construction of the Boardman-to-Hemingway 500 kV transmission line, among other action items.[5]

Planned investment in the Preferred Portfolio differs from PacifiCorp's Fall 2022 Business Plan ("Business Plan") primarily due to reductions or delays in the 2020 All Source Request for Proposals wind, solar, and battery storage resources in the Business Plan.[6] The Preferred Portfolio also reflects lower reliance on FOTs. In addition, CO2 emissions over the study period decreased by 9 million tons relative to the Business Plan.[7]

B. The IRP Process and Standard of Evaluation

Utah Code Ann. § 54-1-10 requires the PSC to "engage in long-range planning regarding public utility regulatory policy in order to facilitate the well-planned development and conservation of utility resources." The PSC relies in part on PacifiCorp's IRP process to fulfill this planning requirement to meet the electrical needs of PacifiCorp's Utah service territory. In 1992, the PSC developed and approved the Guidelines that govern the IRP process.[8] PSC acknowledgment of an IRP means it substantially complies with these Guidelines. Such acknowledgment, however, does not constitute PSC approval of any specific PacifiCorp resource acquisition decision or

[5] *See id.*, at 27-33.
[6] *See id.*, at 335-336.
[7] *See id.*
[8] Information on historic PacifiCorp Integrated Resource Plans can be found at the following link: https://psc.utah.gov/electric/historic-integrated-resource-plans/.

strategy for meeting its obligation to serve. Resource approval and cost recovery are addressed in dockets separate from the IRP.

II. SUMMARY OF ISSUES ADDRESSED IN COMMENTS

As discussed in more detail below, several parties urge us not to acknowledge this IRP. Many express serious concerns regarding the limited time afforded for their review, evaluation, and meaningful input. The challenges PacifiCorp has faced meeting IRP schedule deadlines are evident in the fact it has requested substantial extensions in each of the last three IRP cycles. Parties contend there was no opportunity for their review and feedback on modeling results and the P-MM Preferred Portfolio before the preliminary 2023 IRP was filed. Consequently, some dispute that the P-MM Preferred Portfolio represents the least-cost, least-risk resource portfolio. Additionally, many parties expressed concern over the suspension of the 2022 All Source Request for Proposals (the "2022 AS RFP") and its impact on the Action Plan. Finally, several parties, including the DPU and OCS, challenged various specific modeling inputs, assumptions, and studies, asserting:

a) inconsistent or insufficient analysis, or disparate treatment, of resources;

b) insufficient analysis of federal and state incentives and potential savings opportunities from the IRA and the Energy Infrastructure Reinvestment ("EIR") program;

c) insufficient discussion and analysis of regional transmission planning;

d) inadequate modeling and evaluation of advanced transmission technologies, grid-enhancing technologies ("GET"), and other alternatives to new transmission construction; and,

e) inadequate transparency and discussion related to PacifiCorp's reliability and granularity adjustments.

III. PARTIES' POSITIONS ON ACKNOWLEDGMENT OF THE 2023 IRP

Parties' Comments

DPU, OCS, and UAE recommend the PSC not acknowledge the 2023 IRP. DPU argues 1) its submission was two months late with the last of the supporting documents filed on June 20, 2023;[9] 2) Natrium was included in the Preferred Portfolio without sufficient analysis of costs, timing, and risks to customers in light of the large costs and schedule overruns of other nuclear projects in the country; 3) the 2022 AS RFP was suspended without explaining its impact on the Action Plan;[10] 4) the assumption that non-emitting peaker plant technology will be commercially available by 2030 is inappropriate given the technology is unproven and its operating costs are unknown; and 5) some resources and technologies, like nuclear and non-emitting

[9] DPU Comments, at 2 and 4, filed December 12, 2023 ("DPU Comments"). DPU comments this is the third straight instance the IRP was filed two or more months after the March 31 deadline.
[10] DPU explains the assumptions that served as model inputs may change significantly by the time PacifiCorp performs more modeling, reiterating that "[t]hrough the end of 2026, the 2023 IRP Preferred Portfolio includes an additional 745 MW of wind and an additional 600 MW solar co-located with storage, for which the 2022 AS RFP [was] … soliciting and evaluating resources to fulfill." *Id.*, at 15 (quoting the IRP, at 35).

peakers, are unjustifiably favored and others, like new natural gas resources and CCUS technologies, are unjustifiably excluded.[11]

OCS argues PacifiCorp failed to meet Guidelines 3, 4.b., 4.e., 4.g., and 4.h. OCS states PacifiCorp did not provide any modeling results to stakeholders for review and feedback until after it had filed the preliminary IRP.[12] Additionally, OCS joins DPU in asserting natural-gas-fired resources were not evaluated on a comparable and consistent basis relative to unproven technologies like Natrium and non-emitting hydrogen peakers. OCS also objects that an appropriate customer rates impact analysis was not provided. Finally, OCS notes the suspension of the 2022 AS RFP may negatively impact system reliability within the next four years, leading OCS to challenge whether the Action Plan reflects least-cost, least-risk resources.

UAE comments PacifiCorp withheld the results of any modeling runs, including the Preferred Portfolio, from stakeholders before filing its preliminary 2023 IRP, contrary to Guideline 3. UAE believes PacifiCorp's actions prevented UAE's reasonable and meaningful participation in the selection of the Preferred Portfolio.[13]

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[11] DPU notes that the CCUS technology was the top-performing variant case using medium gas/medium CO2 assumptions, with a present-value revenue requirement ("PVRR") of $507m under the P-MM Preferred Portfolio. It was also a top performer under various other scenarios. Regarding new gas resources, DPU explains PacifiCorp assumed a 10-year cost recovery period rather than a typical 40-year period (DPU Comments, at 24). This unusual assumption was made without stakeholder input and, to DPU's knowledge, was first announced after PacifiCorp submitted the preliminary IRP.
[12] OCS Comments, at 1-2, filed December 12, 2023 ("OCS Comments").
[13] UAE Comments, at 3, filed December 12, 2023 ("UAE Comments").

UAE also expresses concern about the inclusion of Natrium in the Preferred Portfolio. UAE explains the lack of information about Natrium's cost and performance assumptions impeded any independent evaluation. UAE states PacifiCorp in effect forced the model to select Natrium. This modeling approach cannot be viewed as providing consistent and comparable treatment of competing resources.[14]

UCE recommends the PSC acknowledge the 2023 IRP and explains UCE is encouraged by PacifiCorp's planned increases in wind, solar, and storage resources in the 2023 IRP.[15]

WRA takes no position regarding the acknowledgment of the 2023 IRP. But it joins other parties in asserting that time constraints negatively impacted the accuracy of the modeling and the opportunity for public input. WRA explains that the preliminary 2023 IRP, the final 2023 IRP, and the accompanying supporting workpapers include significant errors — far more than is typical. In WRA's view, many portfolio results don't make sense.[16] These discrepancies, according to WRA,

[14] *Id.,* at 9.
[15] UCE Comments, at 3, filed December 12, 2023 ("UCE Comments").
[16] As an example, WRA described that several portfolios show inexplicable disparities particularly in early years where system resources should be more or less identical including a comparison of portfolio variant P05-No Nuclear and P06-No Forward Technology. WRA explains that given nuclear and non-emitting peakers are not selected in either portfolio until 2030, the expectation was that the portfolios would differ only in future years but that there were large discrepancies in market purchases appearing in the first three years of the modeling period, despite no difference in system need or expansion options in those early years. WRA Comments, at 11, filed December 12, 2023 ("WRA Comments").

undermine its confidence in the results and support its view the IRP was filed before it was ready for stakeholder analysis.

Interwest recommends either the PSC decline to acknowledge the 2023 IRP or conditionally acknowledge certain parts thereof and the Action Plan.[17] Interwest states the 2022 AS RFP's suspension casts extreme uncertainty over the Action Plan. Interwest calls for increased scrutiny of Natrium and non-emitting peaker resource technologies in the Preferred Portfolio, as they "do not reflect the least cost/least risk" resources".[18] Interwest also recommends the PSC direct PacifiCorp to resume the 2022 AS RFP as soon as possible.

Sierra Club recommends the PSC acknowledge the planned new renewable resources in the 2023 IRP but argues the Plan's coal retirement timelines, gas conversions, and nuclear additions "are extremely risky for ratepayers" and do not warrant acknowledgement.[19] Sierra Club also expresses concern about the suspension of the 2022 AS RFP.[20]

PacifiCorp's Reply

PacifiCorp asserts its 2023 IRP and Action Plan comply with the Guidelines and were developed after substantial stakeholder input. PacifiCorp asserts it held eleven public-input meetings and six state-specific input meetings.[21] The 2023 IRP public-

[17] Interwest Comments, at 3, filed December 12, 2023 ("Interwest Comments").
[18] *Id.*, at 6.
[19] Sierra Club Comments, at 3, filed December 12, 2023 ("Sierra Club Comments").
[20] *Id.*
[21] PacifiCorp Reply Comments at 12, filed January 31, 2024 ("PacifiCorp Reply Comments").

input process materials covered inputs, assumptions, risks, modeling techniques, and analytical results. PacifiCorp states it considered and implemented the PSC's direction in developing the 2023 IRP. It further asserts the Preferred Portfolio is supported by a detailed analysis of: 1) key inputs and assumptions to inform the modeling and portfolio-development process; 2) a wide range of resource portfolios; 3) a targeted reliability analysis to ensure portfolios have sufficient flexible capacity to meet reliability requirements; 4) evaluation of the resource portfolios to measure comparative costs, risks, reliability, and emission levels; and 5) development of a near-term resource Action Plan required to deliver resources in the Preferred Portfolio.[22]

PacifiCorp asserts the 2023 IRP benefited from various modeling advancements[23] and that through an extensive IRP process PacifiCorp was able to develop a Preferred Portfolio that meets its long-term goals of providing reliable and affordable service to its customers.

IV. DISCUSSION, FINDINGS, AND CONCLUSIONS

A. SUSPENSION OF THE 2022 ALL SOURCE RFP

OCS, DPU, Interwest, and Sierra Club assert the suspension of the 2022 AS RFP in September 2023 is problematic and, according to OCS, violated Guideline 4.e. OCS explains, and DPU agrees, the 2022 AS RFP suspension directly impacts the

[22] *Id.*, at 4.
[23] See 2023 IRP, Volume I, at 18-19.

assumptions and selection of resources in the 2023 IRP because the types of resources that were expected to emerge from the 2022 AS RFP may no longer be available and may not be ready for commercial operation by the date required. According to OCS, this could result in increased exposure to market price risks, especially in the event of extreme weather like the September 2022 western heatwave.[24]

DPU and Interwest assert the suspension of the 2022 AS RFP raises serious doubts as to whether the 2023 Action Plan can be implemented.[25] Likewise, Sierra Club states it is highly concerned over PacifiCorp's decision to pause the 2022 AS RFP, especially after the 2023 IRP shows an even greater need for new renewable resources than was forecast in the 2021 IRP.[26]

PacifiCorp responds it suspended the 2022 AS RFP in September 2023, after it had filed the 2023 IRP.[27] It explains its decision was based on a stay of the U.S. Environmental Protection Agency's ("EPA") proposed OTR; ongoing EPA rulemaking on greenhouse gas emissions; wildfire risk and associated liability; and, evolving extreme weather risks.[28] It argues that it complied with Guideline 4.e. and that IRP acknowledgment means not that the Action Plan or Preferred Portfolio selections are

[24] OCS Comments, at 4.
[25] DPU Comments, at 14; and Interwest Comments, at 5-6.
[26] Sierra Club Comments, at 3.
[27] PacifiCorp Reply Comments, at 16.
[28] The OCS argues that all of these factors were known and included in the final 2023 IRP when it was filed on May 31, 2023; and therefore, was surprised PacifiCorp named the same factors as the reason for suspending the 2022 AS RFP in September 2023.

valid into perpetuity but rather, that the IRP and resulting Action Plan are appropriate given the conditions at the time of filing.

We conclude PacifiCorp's decision to pause the 2022 AS RFP substantially impacts the Action Plan and greatly reduces its value and trustworthiness. The PSC recognizes at least some of the reasons PacifiCorp offers for pausing the RFP were known to PacifiCorp at the time it filed its final 2023 IRP in May 2023. Nevertheless, while certain parties recommend the PSC direct PacifiCorp to reinstate the 2022 AS RFP, such proposals are outside the scope of this docket.

B. MODELING ISSUES, ASSUMPTIONS, AND RESOURCE SELECTIONS

1. Consistent and Comparable Treatment of Resources

a. *Natrium*

DPU, OCS, UAE, and Interwest argue that PacifiCorp either forces the selection of Natrium in the Preferred Portfolio or inputs favorable assumptions to ensure the model always selects Natrium. For example, UAE notes that unlike every other generation resource considered in Table 7.1 of Chapter 7 of the 2023 IRP (showing costs and performance information for all supply-side resources), Natrium is not included.[29] Rather, PacifiCorp's cost and performance assumptions for Natrium are unknown to stakeholders. According to UAE, this allows the assumed costs of Natrium to "move" in the model such that they purportedly always provide benefits to

[29] UAE Comments, at 7.

customers.[30] UAE contends this also ensures that Natrium is always selected by the model.[31] PacifiCorp justifies this treatment by stating that it is in commercial discussions with TerraPower and will not move forward unless there are benefits for customers. UAE concludes Natrium's treatment in the model is not consistent and comparable with the treatment of other resources.

DPU states PacifiCorp has never responded to requests for 1) Natrium's costs and performance factors and 2) a timeline with major milestones that shows a path to achieving an online service date of 2030.[32] DPU also contends that since no details are available to stakeholders, it is impossible to evaluate Natrium on a comparable and consistent basis with other resources. DPU concludes that until an agreement is finalized, federal funding is certain, and a timeline is provided, Natrium is a speculative resource that should not be in the Preferred Portfolio.[33]

PacifiCorp responds that its selection of Natrium in the P-MM Preferred Portfolio was based on substantial grants from the Department of Energy (DOE), Natrium's development by TerraPower, the alternative path analysis, the OTR and other federal regulatory requirements, and the obligation to provide least-cost, least-risk portfolios.[34] It explains TerraPower bears all development risks and asserts it has not signed any agreements with TerraPower. It reiterates it will only move forward if

[30] *Id.*, at 9.
[31] *Id*.
[32] DPU Comments, at 21.
[33] *Id.*, at 19.
[34] PacifiCorp Reply Comments, at 35.

Natrium brings value to customers. PacifiCorp indicates the risks associated with Natrium are mitigated because Natrium alternatives require much shorter lead-times than nuclear projects and ample opportunities to meet future electric demand will emerge, before it commits to Natrium.[35] PacifiCorp also reiterates the potential realization of Natrium does not fall within the two- to four-year Action Plan window and explains that Natrium was intentionally limited to years outside of the Action Plan.[36]

b. *Non-Emitting Peaker Plants*

DPU, OCS, and Interwest contend that PacifiCorp favors non-emitting peaker resources (turbines running on 100 percent hydrogen) by assuming they will be available and commercially viable by 2030 even though no such utility scale technology is currently operating. Both DPU and Interwest note the production and transportation plans for hydrogen for utility-scale energy generation are also currently only in the design phase.[37] They explain that while hydrogen could be delivered using a pipeline network from a centralized remote facility, these pipelines do not currently exist. Given these facts, the parties question the selection of the resource for the P-MM Preferred Portfolio.[38] DPU comments it is impossible to

[35] *Id.*, at 36.
[36] *Id.*, at 37.
[37] DPU comments, at 3 and 22.
[38] In response to a data request, PacifiCorp responded that its modeling of this technology assumes 1) the expense of the needed pipeline, as well as 2) its ability to procure hydrogen at market prices based on forward price curves and projections showing low hydrogen production costs and federal tax credits for 100 percent hydrogen. DPU Comments, at 22-23.

analyze PacifiCorp's cost information since such plants are not commercially operating, and DPU has no way to test any data supporting PacifiCorp's assumptions.[39] DPU adds that the timelines PacifiCorp uses for availability of non-emitting peakers may also be optimistic, and argues that assuming a specific date for this non-emitting resource is speculative.

Interwest criticizes non-emitting peaking resources' selection in the Preferred Portfolio stating that a 20 percent hydrogen blending ratio is inadequate to achieve emission performance requirements because it achieves only a marginal decrease of 6-7 percent in carbon emissions at the gas generating unit.[40] Additionally, there is evidence a sustained green hydrogen supply-chain does not exist.

In response, PacifiCorp states that its main goal is selecting a Preferred Portfolio with the best combination of expected costs and associated risks and uncertainties.[41] Thus, in creating a 20-year plan, it does not limit resources to only those currently estimated to be commercially viable within the planning horizon. Rather, it considers associated risks when it includes resource options. PacifiCorp believes non-emitting peakers, like nuclear, will achieve wider commercial use outside of the two- to four-year Action Plan window and restricts their selection on that basis. PacifiCorp also explains that the alternative path analysis indicates ample

[39] *Id.*, at 22.
[40] Interwest Comments, at 11.
[41] PacifiCorp Reply Comments, at 41.

opportunity for adjustment to these proxy resource selections based on future analysis.

c. *CCUS Technology*

DPU contends PacifiCorp's planning is biased against CCUS technologies. For example, DPU states that variant P20 JB3-4 CCUS ("P20") (which includes CCUS technology), was the top-performing variant case using the medium gas/medium CO2 assumptions, with a PVRR of $507 million *under* the P-MM Preferred Portfolio variant (using short-term ("ST") value).[42] Variant P20 was also the top performer under a risk-adjusted cost metric and was third in the CO2 emissions category.[43] It was also the top ST cost performer under both the medium gas/zero CO2 scenario and the high gas/high CO2 scenario, and was the top emission performer under both of these scenarios.[44]

PacifiCorp responds that CCUS technologies have shown significant cost uncertainty and only two major utility-scale CCUS retrofit projects are commercially operating.[45] PacifiCorp conceded the P20 variant was the top performer under both ST and risk-adjusted evaluations, but explained it did not choose it for the Preferred Portfolio because 1) the CCUS assumptions are not based on bids or proposals from CCUS technology companies but are proxy assumptions for project-specific costs and

[42] DPU Comments, at 24.
[43] *Id.*
[44] *Id.*
[45] PacifiCorp Reply Comments, at 39.

operational characteristics; 2) the scale of the proposed CCUS technology has never been demonstrated on a coal plant operating commercially anywhere in the world; 3) while feasibility studies for amine-based CCUS at Jim Bridger ("JB") units 3 and 4 have been done, PacifiCorp currently does not have evaluation or equivalent cost data to that of a front-end engineering and design study; 4) the updated fueling strategy to source coal for JB exclusively from the Powder River Basin has not been previously attempted by PacifiCorp; and 5) other limitations, challenges, and risks. In response to a question about whether these risks were analyzed by its model, PacifiCorp indicated its rejection of the P20 variant in the Preferred Portfolio was more of a judgment call.[46]

d. *New Natural Gas Plants*

According to DPU and OCS, PacifiCorp's planning is also biased against generating facilities fueled by natural gas and coal. For example, DPU states PacifiCorp informed stakeholders for the first time in the April 13, 2023 public input meeting that in most scenarios, the recovery period for the costs of new gas resources is assumed to be 10 years to account for PacifiCorp's perceived risks in investments in new carbon emitting resources.[47] DPU requested results from a portfolio variant assuming instead a 40-year cost recovery horizon as realistically in line with new natural gas resources and PacifiCorp responded by producing variant

[46] DPU Comments, at 24-25.
[47] *Id.*, at 30.

"P24-Gas 40-year Life" ("P24"). PacifiCorp describes it as a variant of the P-MM Preferred Portfolio that changes the technical life assumption for proxy gas resources from 10 years in the base study to 40 years. According to PacifiCorp, this change produced different results. First, the model selected gas units as replacements for any coal retirements, instead of the nuclear or non-emitting peaking options in the P-MM Preferred Portfolio.[48] Second, the "cost of gas pipelines led the model to keep" the Hunter 2 and 3 coal plants running through 2042.[49] Third, the model selected significantly less early DSM.[50] DPU criticizes PacifiCorp's arbitrary decision to change the expected life of new natural gas plants arguing several natural gas plants are currently in different stages of development across the country.[51] DPU also notes the PSC declined to acknowledge the 2021 IRP for a similar reason — PacifiCorp's unilateral decision to force the model to exclude new natural gas plants altogether. DPU explains the decision to constrain the life of a new natural gas plant resulted in an inappropriate Preferred Portfolio. PacifiCorp responds that for the first time, it allowed the model to endogenously select natural gas conversions for a broader set

[48] *Id.*, at 26-27.
[49] *Id.*
[50] *Id.*, at 27 (DPU referencing the 2023 IRP, Volume I, at 305).
[51] DPU presents a map showing natural gas plants that were announced, in early development, in advanced development and under construction in 2023 which DPU states illustrates that many utilities do not attribute the same risks to natural gas plants that PacifiCorp does. DPU Comments, at 29 (Figure 5 – Planned New Natural Gas Plant (S&P)).

of units. According to PacifiCorp, this enhancement expands opportunities for natural-gas-fired operation compared to prior IRPs.[52]

DPU also challenges the final step PacifiCorp used to select the Preferred Portfolio. After all of the variants were run through the model, PacifiCorp explains its decision to select the P-MM variant as the Preferred Portfolio was driven by "consideration of current policies in motion and unmodeled risks for which ongoing trends recommend the adoption and development of tax-supported renewable projects … ."[53] In response to a request for calculations or other supporting data for these subjective criteria, PacifiCorp stated there were no records or calculations to review.

e. *We Find and Conclude PacifiCorp Failed to Treat Resources on a Consistent and Comparable Basis*.

Guideline 4.b. requires "[a]n evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis." In addition, 4.b.iii. states "resource assessments should include: life expectancy of the resources… ."

We find, based on the evidence, that PacifiCorp overlooked the negative attributes of Natrium in its analysis and withheld confidential costs and performance information that were necessary to compare Natrium on a consistent and comparable

[52] PacifiCorp Reply Comments, at 37-38.
[53] 2023 IRP, Volume I, at 306.

basis relative to other resources. Natrium certainly has potential due to its unique characteristics as described in PacifiCorp's reply comments.[54] However, the IRP contains no discussion of the potential for significant cost overruns or delayed construction timelines typical to the development and construction of nuclear projects. Natrium was selected as a least-cost, least-risk resource in the Preferred Portfolio based solely on its positive, unique attributes. We recognize the sensitivity of PacifiCorp's costs and performance assumptions for Natrium; however, our process provides protections for highly confidential information that may have allowed parties to perform at least a general cost analysis, and PacifiCorp failed to use it. We find it is impossible to compare Natrium with other resources on a comparable and consistent basis without cost and performance assumptions and a realistic assessment of all the potential attributes of Natrium, both positive and negative.

We also find disparate treatment by PacifiCorp of non-emitting resource technologies relative to CCUS technologies. For example, despite the P20 CCUS variant being the top or near the top-performing variant under five different scenarios,[55] PacifiCorp did not select it as a least-cost, least-risk resource in the Preferred Portfolio. The reasons PacifiCorp argues for rejecting CCUS, e.g., that cost assumptions are not based on bids and commercial operation is unproven, apply with

[54] PacifiCorp Reply Comments, at 36.
[55] *See* DPU Comments, at 24.

equal, if not greater, force to the Natrium and non-emitting resource technologies PacifiCorp includes in the P-MM Preferred Portfolio.

Finally, the use by PacifiCorp of a 10-year life for new natural gas plants was arbitrary and unjustified, and prevented their consistent and comparable treatment relative to other resources. The PSC recognizes risks may exist to natural gas plant lifespans attendant to the OTR and other federal regulations. Such risks are inherent in the planning process and require analysis and articulated reasoning on how best to measure and account for them. In this instance, however, the restriction on useful life is unilateral and arbitrary. Neither the OTR nor any other federal regulation changes the depreciable lives of natural gas plants from 40 to 10 years. Moreover, any Oregon, Washington, and California laws that may impact the lives of new natural gas plants do not apply in Utah. Accordingly, the PSC finds that PacifiCorp did not treat natural gas plant options on a comparable and consistent basis relative to other resources, contrary to Guidelines 4.b., 4.b.iii., and 4.h.

2. Reliability and Granularity Adjustments

Sierra Club requests PacifiCorp clarify its methodology for its reliability adjustments and explain the reason the long-term model produces significant energy shortfalls that must be manually addressed. Sierra Club also requests an opportunity to recommend alternative reliability adjustments, and clarification of the values

PacifiCorp uses in the granularity adjustments.[56] Sierra Club suggests that PacifiCorp base its coal units' granularity adjustments on total fuel costs.[57]

PacifiCorp explains that both reliability and granularity adjustments are specific measures that address specific enhancements and there are no logical alternatives because both procedures are dictated by model math.[58] It further explains that in extreme cases where the adjustments exceed plus or minus $100/kW-year, it limits the adjustment to plus or minus $100/kW-year to prevent the granularity adjustment from overwhelming long-term outcomes based on extreme values driven by conditions that will not be relevant in final reliable portfolios.[59] PacifiCorp comments it makes resource adjustments on the basis of measured deficiencies and by applying calculated resource values to determine the appropriate action to cover deficiencies. It states its approach is specific to stated goals and a direct application of model outcomes to improve results. We find PacifiCorp's explanations to be reasonable and sufficiently responsive to Sierra Club's requests. Therefore, we find that no additional information related to its reliability and granularity adjustments is necessary.

[56] Sierra Club Comments, at 4.
[57] *Id.*, at 4 and 42.
[58] PacifiCorp Reply Comments, at 19.
[59] *Id.*, at 20.

3. Customer Rate Impact Analysis

In response to OCS's claim that PacifiCorp failed to comply with Guideline 4.g. by not including a customer rate impact analysis, PacifiCorp states that the IRP includes an indicator of customer rate pressure over time among the initial portfolios relative to the P-MM Preferred Portfolio. It explains that Volume II, Appendix J, stochastic simulation results show incremental and cumulative estimated customer rate impacts over the 20-year planning period that apply equitably across all classes of ratepayers.[60] PacifiCorp indicates that while the approach provides a reasonable representation of relative differences in projected total system revenue requirement among portfolios, it is not a prediction of future revenue requirement for ratemaking purposes. PacifiCorp also explains that the IRP is informed by proxy resources where exact costs cannot be known until specific resources are known. We find, based on PacifiCorp's explanation and our review of Volume II, Appendix J, including the figures showing net differences in total system costs, that its analysis meets Guideline 4.g., and no additional analysis is necessary.

4. Miscellaneous Changes to the Presentation of Data

Alternative Portfolio Variants, Cluster Resources, and Scenarios. In response to Sierra Club's request for PacifiCorp to complete model runs of P01-JB3-4 GC, P04-Huntington RET28, and P17-Col3-4 RET25 variants under all of the different pricing

[60] *Id.*, at 22.

scenarios, PacifiCorp responds that because it is constrained from evaluating all studies under all possible conditions, it must prioritize which model variant to analyze. It bases its decisions on the likely investigative value. PacifiCorp states the P01, P04, and P17 results, for example, are so conclusive that further analysis under other, less likely, price scenarios doesn't add likely investigative value. PacifiCorp states that P17, for example, was examined only to determine the cost-effectiveness of an early retirement of both Colstrip units over the optimally selected approach of retiring one unit and continuing the other. PacifiCorp also explains the 2023 IRP evaluates portfolios under five price policy scenarios with attention to investigative value and resource availability. PacifiCorp states it cannot evaluate all studies under all possible conditions and therefore prioritizes cases. At the same time, PacifiCorp asserts, it has been responsive to stakeholder requests, conducting additional studies as time and resources allow.

PacifiCorp explains that the analysis of P18 and P19 likewise was conducted with the understanding that additional resources would likely result in a higher cost PVRR outcome and that the value of the studies was to assess the magnitude of that PVRR impact to determine possible least-regret paths to consider for the Preferred Portfolio. It further explains that the results of the studies supported the selection of the Preferred Portfolio without the additional marginal cluster resources in the East or West.

We find PacifiCorp's explanation that it cannot evaluate all studies under all possible conditions, and therefore prioritizes cases, is reasonable. We also find that PacifiCorp has been responsive to stakeholder requests for alternative and additional model runs, conducting additional studies as time and resources allow, and that running the proposed additional variants would produce more portfolios but would not change the final outcome and, therefore, be of limited value. Based on this, we find it is unnecessary for PacifiCorp to run the requested additional modeling.

Coal fuel costs for JB and pipeline capacity for conversions. We find PacifiCorp's response to the request that it use the base tier pricing from the 2023 JB long-term fuel plan for the JB plant, to be reasonable. PacifiCorp states that the fixed and variable cost structure assumed in the 2023 IRP captures the cost of continuing or ceasing coal-fired operation at JB units 3 and 4. It explains that opportunities to optimize coal supply for particular circumstances are ill-suited for modeling in the IRP and provide limited incremental benefit.

We also find PacifiCorp's response to Sierra Club's request that PacifiCorp provide an assessment of the availability and cost of firm interstate pipeline capacity necessary to supply its planned coal to gas conversions in the 2023 IRP Update, to be reasonable. PacifiCorp explains that due to confidentiality agreements between it and third-party entities, it is unable to disclose any terms on firm interstate pipeline capacity for planned conversions.

Carbon. Sierra Club recommends PacifiCorp increase the medium carbon price assumption to reflect recent federal regulations and incorporate the developments in the 2023 IRP Update. According to PacifiCorp, the request is based on a misunderstanding of the medium CO2 price assumption cost function. It explains that the medium CO2 price assumption is a proxy for future drivers. Its CO2 proxy cost forecast represents an established trend of decarbonization into the future and is based on a survey of (then) currently available forecasts. PacifiCorp explains that it is not the role of the proxy cost to drive decarbonization, rather its role is to represent drivers that can be reasonably forecast. It further explains its forecasting of the decarbonization trend will continue into the future. Regarding the request for elimination of "the medium gas price, zero CO2 price ('MN') price-policy scenario or zero CO2 ('LN') price-policy scenarios generally,"[61] PacifiCorp states this would generally eliminate a source of information from the robustness of portfolios that indicates what may occur if the expected case CO2 proxy forecast is not realized. PacifiCorp asserts that while the medium gas price-policy scenario is the most likely, eliminating it or any alternative, as requested, is unnecessary. We find PacifiCorp's response credible. On this basis, we find that it is unnecessary to run the requested analyses.

[61] *Id.*, at 26.

Collocated Resources. UAE recommends the PSC direct PacifiCorp to make its requested changes to Tables 9.31, 9.32, and 9.33, and Figures 9.60 and 9.62 in future IRP filings. UAE's main concern is that the tables lack detail on whether the generation and storage resources shown are collocated or standalone resources. PacifiCorp responds that collocation information is illustrated in Figure I.1 of the 2023 IRP. It lists the portfolio resources selected by location and year, including solar and wind resources that are collocated with storage. PacifiCorp also refers to the discussion on the expansion of collocation opportunities in section III.A.2 – *Process Improvements,* in the 2023 IRP indicating that collocation options are no longer constrained in the modeling. We find PacifiCorp's explanation is responsive to UAE's requests; therefore, we decline to order the requested changes in future IRP filings.

Surplus Interconnection. Sierra Club requests PacifiCorp allow storage to be paired with not only new renewable resources, but also existing fossil fuel resources. According to Sierra Club, this use of a thermal asset with a storage resource "would increase the flexibility of the asset and provide lower emission reliability services, such as spinning reserve" and likely "reduce operating costs as the storage asset could operate more responsively."[62]

PacifiCorp responds that it has modeled surplus interconnection in the 2023 IRP, where storage resource options were available to be selected with potentially

[62] Sierra Club Comments, at 55-56.

any technology or combination of technologies, allowing portfolio optimization to recognize the best location, size, and timing for storage concurrently with considerations of existing technology profiles, and also in tandem with thermal retirement options. PacifiCorp adds that storage options that were not part of a cluster study were considered unconstrained by transmission requirements, such that any amount could be placed at any modeled location on the system. It explains that its strategy has exceeded the requests by allowing the model to make the best collocation determinations endogenously and refers Sierra Club to the IRP discussion of expanded collocation opportunities in section III.A.2 – *Process Improvements*. We find PacifiCorp's response to be reasonable and find that PacifiCorp has already modeled the requested interconnection scenario, and no additional modeling is necessary.

C. PROCESS ISSUES

DPU contends the 2023 IRP was filed after the March 31 deadline for the third IRP cycle in a row, and the continual filing delay disadvantages stakeholders as it compresses their opportunity to review and evaluate the IRP. DPU explains it agreed to PacifiCorp's extension request because it was the least objectionable alternative. OCS, UAE, and UCE also contend that PacifiCorp's failure to provide the modeling results to stakeholders before it filed the preliminary IRP prevented them from having any opportunity to review, evaluate, and provide public input, which OCS and UAE claim violates Guideline 3. DPU and OCS note that even the media knew the modeling

results before stakeholders who invest significant time and resources into the IRP planning process. UCE agrees that PacifiCorp should provide the modeling results to stakeholders to allow for sufficient review before filing the IRP. WRA also joins DPU, OCS, UAE, and UCE in the overall concern that time constraints impact not only the ability to appropriately review, evaluate, and provide input, but also lessen the accuracy and quality of the IRP. WRA also asserts the current IRP process and timeline do not work and suggests the PSC make a structural change.

PacifiCorp responds the two-month extension to file the 2023 IRP by May 31, 2023 was necessary to allow PacifiCorp to incorporate recent federal and state law changes such as the OTR, the IRA interconnection rules, and other state regulatory requirements. PacifiCorp asserts that while several parties expressed concern over the requested extension, no one recommended the PSC deny it and notes that stakeholders requested PacifiCorp provide a draft IRP in comments related to the 2021 IRP. PacifiCorp further asserts the extended stakeholder engagement process enhanced the accuracy and comprehensiveness of the IRP that led to a significantly improved analysis in the final 2023 IRP. In sum, PacifiCorp notes that the public input process affords many opportunities for comment and quotes the PSC stating, "'[t]he purpose[] of the process is *not* to allow stakeholder[s] an early preview of what

PacifiCorp has [ultimately] elected to do. The purpose is to allow them an opportunity to provide meaningful feedback at each stage of a collaborative process.'"[63]

Our direction on the interpretation of Guideline 3 has been clear. The opportunity for stakeholders to examine and provide information during the IRP development, rather than after the fact, is an important aspect of the process.[64] The IRP is to be developed in consultation with stakeholders who must have ample opportunity for meaningful feedback and information exchange during the development of the plan and at each stage of the process.[65] In this docket, PacifiCorp did not share its modeling results and the Preferred Portfolio, two of the most critical aspects of the IRP, with stakeholders until after it filed its preliminary IRP on April 3, 2023. This is the first time that PacifiCorp has not provided modeling results and Preferred Portfolio selections before making its IRP public. However, this is also the first time that we have added an extended filing period that included the filing of a preliminary IRP and a comment deadline. In light of the uncertainties created by this new procedure, we do not find PacifiCorp violated Guideline 3. Nevertheless, we

[63] PacifiCorp Reply Comments, at 11. In quoting the PSC's order about the purpose of the process, PacifiCorp unfortunately misinterpreted our language and quoted it out of context. The PSC was reacting to PacifiCorp's pattern of untimeliness, of presenting meeting materials at the last minute, and of making key modeling decisions without giving stakeholders time to review and provide meaningful input. A major purpose of the IRP Guidelines is to assure PacifiCorp collaborates and shares information with stakeholders before decisions, in particular crucial ones like the selection of the Preferred Portfolio, are made.

[64] PacifiCorp's 2017 Integrated Resource Plan, Docket No. 17-035-16, Report and Order issued March 2, 2018, at 7-8.

[65] *Id.*, at 7.

remain troubled by the evident lack of collaboration, in particular with respect to key decision points in the IRP planning process. Here, parties did not collaborate on the most consequential aspects of the IRP — modeling results and the Preferred Portfolios - before the preliminary IRP became public. Therefore, in this order we provide notice that in all future IRP dockets, Guideline 3 will apply to preliminary IRP disclosures and filings. As we have said before, PacifiCorp must provide parties ample opportunity to review, analyze, and provide meaningful input at all stages of the IRP process. Moreover, this must be done with adequate time for PacifiCorp to evaluate and, as appropriate, apply that input before filing any IRP, whether preliminary or final.

D. MISCELLANEOUS REQUESTS RELATED TO THE 2025 IRP

Modeling extreme weather events.

The OCS and DPU recommend PacifiCorp include in its modeling the effects of long-lasting extreme weather events. OCS specifically cites the September 2022 heatwave and the February 2021 Texas extreme cold event as examples of the types of weather events that should be modeled in order to identify potential system reliability issues. PacifiCorp responds that it already models several weather scenarios, and will continue to model them in upcoming IRP cycles. It explains that it not only considers climate change within its baseline forecast, but within multiple load forecast scenarios. As an example, PacifiCorp states that the 1-in-20-year extreme weather scenario evaluates peak weather impacts using the most extreme peak

observed over the past 20 years. PacifiCorp also states the 20-year normal weather scenario evaluates the weather impacts on load assuming weather is consistent with the average temperatures observed over the prior 20 years.

We find PacifiCorp's modeling of weather scenarios amply addresses OCS's concerns. To the extent other methodologies for modeling extreme weather events arise, we encourage PacifiCorp to study and discuss them with stakeholders during the IRP planning process.

Modeling GET.

OCS asserts the IRP model does not, but should, contain a process to evaluate GET or other advancements to maximize the efficiency of the grid. OCS explains that by avoiding construction of very costly transmission lines or transmission interconnection activities, GET could enable the development of lower cost Preferred Portfolios. Likewise, Interwest recommends that PacifiCorp include GET in future IRPs.

PacifiCorp responds that Chapter 4 and Appendix E of the 2023 IRP review the potential for reconductoring with advanced conductors as well as using other GET. It states it considers and identifies network upgrades using advanced conductors and GET wherever feasible, and this approach provides adequate analysis for the long-term. We find the 2023 IRP sufficiently evaluates GET as evidenced in Chapter 4 and Appendix E. We therefore decline to direct PacifiCorp to perform additional analysis in this area.

Modeling Enhanced Geothermal Systems ("EGS").

UCE recommends PacifiCorp consider evaluating EGS technologies in the 2025 IRP cycle. UCE explains that Utah is home to the Utah Frontier Observatory for Research in Geothermal Energy ("FORGE") project[66] which is sponsored by the Department of Energy for developing, testing, and accelerating breakthroughs in EGS. UCE states that Fervo Energy is developing the 400 MW Cape Station project in Beaver County, Utah that is expected to go online in 2028. UCE concludes that EGS should be added to other emerging technologies like Natrium and non-emitting (hydrogen) resources that PacifiCorp evaluates.[67]

PacifiCorp responds that it studied and updated geothermal technologies as an option in the 2023 IRP, but they were not selected in the Preferred Portfolio. PacifiCorp states it intends to continue to include geothermal options and update its costs and technical assumptions in future IRPs and remains open to considering geothermal competitive bids in its RFP processes.[68] We find, based on PacifiCorp's explanation, that it has considered, and intends to continue to consider, EGS as another emerging technology for evaluation in future IRPs.

[66] UCE Comments, at 7.
[67] *Id.*, at 8.
[68] PacifiCorp Reply Comments, at 31-32.

Federal and state incentives.

Sierra Club recommends PacifiCorp apply tax bonus credits for "energy communities" to all qualifying communities and correct inaccuracies and update its supply side resource workpapers to include the investment tax credits and production tax credits granted under the IRA for storage resources.[69] PacifiCorp responds it will continue to pursue opportunities to share government funding updates with stakeholders.[70] PacifiCorp also states that not all resources planned in the 2023 IRP over the 10-year period qualify for EIR, as Sierra Club appears to imply.

For example, PacifiCorp explains that only company-owned resources would be expected to qualify, and this would exclude non-owned purchase power agreements selected by the RFP process.[71] PacifiCorp reiterates that the long-term IRP is based on proxy resource selection. PacifiCorp asserts that cost-saving opportunities, such as those provided by federal incentives, are addressed during the acquisition process and will manifest through an all-source RFP. PacifiCorp encourages stakeholders to actively monitor PacifiCorp press releases to look for new funding developments.

We find PacifiCorp's response is reasonable. No additional analysis on federal and state funding opportunities is necessary in the IRP. We find that incentive-based

[69] Sierra Club Comments, at 3.
[70] PacifiCorp Reply Comments, at 29.
[71] *Id.*

savings opportunities associated with specific resources are more appropriately considered in the acquisition approval regulatory process.

Participation in Regional Transmission Planning.

Interwest contends that solar-rich regions of PacifiCorp's service territory could provide valued capacity and energy diversity and recommends PacifiCorp include in the next IRP detailed participation updates regarding coordination between NorthernGrid and WestConnect regional planning authorities.[72] Additionally, Interwest suggests the PSC direct PacifiCorp to participate in and report on other transmission planning efforts such as the Western Transmission Expansion Coalition. Interwest further recommends that PacifiCorp include an analysis of potential interconnection points to other utilities.[73]

PacifiCorp responds that participation in regional planning authorities is important and that it is an active member of NorthernGrid and coordinates with WestConnect through NorthernGrid via Interregional Coordination meetings.[74] PacifiCorp points to Volume I, Chapter 3 - Planning Environment, of the 2023 IRP for information on the Western Energy Imbalance Market, Extended Day-Ahead Market, the WRAP, "Markets+" a Southwest Power Pool day-ahead market offering, and other developments to demonstrate it takes an active role in regional planning. It also states

[72] Interwest Comments, at 25.
[73] *Id.*
[74] PacifiCorp Reply Comments, at 43.

that collaborating with other utilities is a common practice in transmission planning, and where feasible, collaborations with other utilities can be used to inform the IRP.[75]

The PSC finds the IRP sufficiently discusses and analyzes PacifiCorp's participation in regional planning and provides adequate information on PacifiCorp's regional market participation and the significant benefits that current energy imbalance market participation brings to customers. The PSC finds it is not necessary to require the requested additional analysis.

Integration costs reporting.

Interwest urges PacifiCorp to study and report in the 2025 IRP the costs of inflexible thermal resources in assigning integration costs.[76] PacifiCorp explains that integration costs represent the incremental cost of holding reserves for additional renewable resources. It states that the number of reserves required is reduced because wind and solar resources are added to a pool of reserve requirements that includes load, wind, solar, and non-dispatchable thermal and hydro resources.[77]

PacifiCorp explains that using a pool of reserves to cover variations reduces the reserve requirement. For example, higher than expected wind output may offset lower than expected solar output, load may drop at the same time as wind output, and both circumstances can result in a reduced need for reserves to be deployed.[78]

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[75] *Id.*
[76] Interwest Comments, at 30.
[77] PacifiCorp Reply Comments, at 44.
[78] *Id.*

PacifiCorp states that as part of the 2025 IRP, it intends to develop updated reserve requirements for load, wind, solar, and non-dispatchable resources, and will present the analysis and results as part of the public input process for stakeholder feedback. PacifiCorp adds that as part of model optimization, PLEXOS ensures these reserve requirements are met by dispatchable resources specific to a given portfolio, where portfolios with more dispatchable resources can fulfill those requirements at lower cost.[79] As a result, integration costs are embedded within the reported cost results. PacifiCorp states that portfolio results do not have a dollar per megawatt-hour integration cost added for wind and solar generation, as these costs are part of the core optimization calculation and in any case differ widely across portfolios and future conditions.

The PSC finds PacifiCorp's explanation that integration costs are embedded within the reported cost results satisfies Interwest's request. Other than PacifiCorp's plan to develop updated reserve requirements and the presentation of its analysis as part of the 2025 IRP public input process, we find that no other analysis at this time is necessary.

[79] *Id.*, at 44-45.

E. PROPOSED STRUCTURAL CHANGES TO THE IRP PROCESS

We recognize this is the third cycle in a row that PacifiCorp has requested and received additional time to finalize its IRP. WRA provides evidence that since 1992, almost half of the IRPs were filed after significant delay and only three were unequivocally timely filed.[80] In this instance, the 2023 IRP, its Action Plan, and Preferred Portfolios were developed in the context of rapidly changing laws and energy policies. This necessitated an extension of the schedule to provide some opportunity for stakeholders to review the modeling results and the Preferred Portfolios. The two-month extension turned out to be too short. Both DPU and WRA note that non-confidential supporting information was not made available to stakeholders until April 17, 2023, confidential information supporting the filing was made available on May 1, 2023 after the April 30, 2023 comment deadline, and final confidential supporting information was filed on June 16 and June 20, 2023. The last of the finalized information was filed more than 11 weeks after the 2023 IRP original due date.

It is evident once again in this IRP cycle that the current IRP planning process, even with the authorized extensions, does not provide sufficient time 1) for PacifiCorp to develop an effective IRP, and 2) for stakeholders to review, evaluate, and provide

[80] WRA states, "[o]f the fifteen planning cycles [since] 1992, three were unequivocally timely; one provided a partial filing on the required date but added an addendum three months later; three were late by days rather than months; but six, close to half, were more significantly delayed … rang[ing] from one month to two-and-a-half years with a median delay of five months." WRA Comments, at 6.

meaningful input at all phases of IRP development. Consequently, we direct DPU, and invite OCS and other IRP participants, to file in this docket by May 30, 2024 recommendations concerning changes to the IRP schedule that will better provide PacifiCorp and all IRP participants adequate time to meet the public collaboration and participation objectives of the Guidelines and described in this and prior IRP orders. We will issue an order outlining the next steps in our consideration of changes to the IRP schedule after reviewing parties' recommendations.

F. THE P-MM PREFERRED PORTFOLIO AND THE LEAST-COST, LEAST-RISK RESOURCE

The fundamental objective of the IRP planning process is to arrive at the least-cost, least-risk resources otherwise known as the Preferred Portfolio. As discussed in detail above,[81] the disparate and inconsistent treatment of Natrium, non-emitting resources, new natural gas plants, and CCUS technologies, resulted in a Preferred Portfolio that fails to withstand scrutiny. Most parties recommended we not acknowledge the 2023 IRP, in part, due to the lack of analytical consistency. DPU put it best that "… small assumptions or changes in inputs can have a large impact on the resource mix ten years down the road … ."[82] The impact of consequential decisions like a dramatic change in the cost recovery period for new proxy gas plants is even greater and should not be made arbitrarily and unilaterally. For these reasons, we

[81] *See* Section IV.B.1. of our Order.
[82] DPU Comments, at 29.

find and conclude the portfolio selection process, and the P-MM Preferred Portfolio, lack credibility and do not acknowledge them.

G. THE ACTION PLAN

The 2023 Action Plan identifies specific actions PacifiCorp intends to take over the next two- to four-year period to deliver resources included in the Preferred Portfolio. PacifiCorp requests that we acknowledge and express support for this Action Plan. Utah Admin. Code R746-430-1 defines "Action Plan" and outlines the contents and supporting information and analysis required. It also states: "Nothing in these rules requires any acknowledgment, acceptance[,] or order pertaining to the Action Plan submitted." Despite that provision, for clarity we state explicitly that we decline to acknowledge or approve the Action Plan submitted with the 2023 IRP. We agree with parties who assert the suspension of the 2022 AS RFP must certainly and substantially impact the Action Plan, yet, on this record we have no way to know exactly how or to what precise degree. Additionally, as with the Preferred Portfolio, the unjustified inconsistencies in the modeling of various resource types cast serious doubts as to the trustworthiness of the resulting Action Plan. In particular, we find the decision to model a 10-year technical life for a proxy new natural gas plant impacts near-term decisions that could prevent customers from potentially attaining significant savings starting in the 2028-2030 period.[83] This finding is corroborated by

[83] *See* Figure 9.45, 2023 IRP Volume I, page 306.

DPU, OCS, and several other parties that urge us to refrain from acknowledging the Action Plan.[84]

V. SUMMARY AND CONCLUSIONS

We recognize the substantial body of quality work completed by PacifiCorp in preparing the 2023 IRP. PacifiCorp filed extensive documentation and workpapers with the 2023 IRP. The level of detail is useful, and the information provided is well organized. We encourage PacifiCorp to continue to provide such detailed back-up data and workpapers in future IRPs.

We also appreciate the diligent efforts and thoughtful comments provided by all parties. We recognize the frustration expressed by many participants with the limitations on their opportunities to provide timely feedback at each stage of the planning process.

After fully considering the 2023 IRP and the parties' comments and reply comments, we acknowledge that, with the exceptions noted, PacifiCorp substantially adhered to the Guidelines in developing its 2023 IRP. Nevertheless, the identified exceptions are of such significance they undermine our confidence in the portfolio selection process, the P-MM Preferred Portfolio, and the Action Plan. Accordingly, we do not acknowledge these aspects of the IRP.

[84] *See e.g.,* Section IV.A. and IV.B.1. of our Order.

VI. ORDER

We direct DPU, and invite OCS and other IRP participants, to file in this docket by **Thursday, May 30, 2024**, recommendations concerning changes to the IRP schedule that will better provide PacifiCorp and all IRP participants adequate time to meet the Guidelines' public collaboration and participation objectives, including those described in this and prior IRP orders.

DATED at Salt Lake City, Utah, April 17, 2024.

/s/ David R. Clark, Commissioner

/s/ John S. Harvey, Ph.D. Commissioner

Attest:

/s/ Gary L. Widerburg
PSC Secretary
DW#333432

Notice of Opportunity for Agency Review or Rehearing

Pursuant to Utah Code Ann. §§ 63G-4-301 and 54-7-15, a party may seek agency review or rehearing of this order by filing a request for review or rehearing with the PSC within 30 days after the issuance of the order. Responses to a request for agency review or rehearing must be filed within 15 days of the filing of the request for review or rehearing. If the PSC fails to grant a request for review or rehearing within 30 days after the filing of a request for review or rehearing, it is deemed denied. Judicial review of the PSC's final agency action may be obtained by filing a Petition for Review with the Utah Supreme Court within 30 days after final agency action. Any Petition for Review must comply with the requirements of Utah Code Ann. §§ 63G-4-401, 63G-4-403, and the Utah Rules of Appellate Procedure.

CERTIFICATE OF SERVICE

I CERTIFY that on April 17, 2024, a true and correct copy of the foregoing was served upon the following as indicated below:

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