BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

PACIFICORP PRUDENCE REVIEW OF GENERATING RESOURCES ACQUIRED SINCE 1986

Docket No. UE-991832

JOINT REPORT

December 7, 2001

EXECUTIVE SUMMARY

This Joint Report is prepared in accordance with the Third Supplemental Order Approving and Adopting Settlement Agreement in Docket No. UE-991832 ("Third Supplemental Order"), in which the Washington Utilities and Transportation Commission (the "Commission") approved a stipulation among PacifiCorp ("PacifiCorp" or the "Company"), Commission Staff, Public Counsel, Industrial Customers of Northwest Utilities, NW Energy Coalition, and the Energy Project (the "Stipulation"). The Stipulation resolved all issues in PacifiCorp's then pending general rate proceeding. The Stipulation included a provision to examine the prudence of certain resource acquisitions made by the Company since its previous general rate proceeding in 1986.

Generally, the Commission measures prudence of resource acquisitions using the following standards:

> [W]hat would a reasonable board of directors and company management have decided given what they know or reasonably should have known to be true at the time they made a decision. This test applies both to the question of need and the appropriateness of the expenditures. (Cause No. U-83-54, Fourth Supplemental Order, p.p. 32-33)
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> Each of the IOUs bears the burden of demonstrating the prudence of new resource acquisitions to the Commission. A demonstration of prudence includes a showing that (1) the selection of each resource was necessary and reasonable, (2) the costs of acquisition were appropriate based upon what a reasonable board of directors and company management decided given what they knew or reasonably should have known to be true at the time the decision was made, and (3) the costs were regularly evaluated. (*Notice of Termination of Notice of Inquiry*, Docket No. UE-940932, April 1998)

This Joint Report culminates the process outlined in the Stipulation to examine the prudence of the following projects: Craig and Hayden, Cholla Unit No. 4, James River Cogeneration Project, Hermiston Cogeneration Project, and Wyoming Wind Project in Foote Creek, Wyoming. This Joint Report presents information regarding the resource acquisitions in a manner that will permit application of the prudence standard. Included in the report for each project is a discussion of the need for the resource, the consideration of alternatives, the reasonableness of the resource costs, information made available to the Company's Board of Directors regarding the resource, and the acquisition process. PacifiCorp's integrated resource planning includes an analysis of demand-side management ("DSM") resources in addition to supply-side resources. A description of the consideration of demand-side resources is also included in this Joint Report. Also included in this Joint Report is a description of the request for proposals for resource acquisition.

As part of its consideration of these and other projects, PacifiCorp utilized integrated resource planning to help guide future decisions regarding energy supply and demand. The integrated resource planning process documents the internal and external processes used by a utility to assess future load growth and the need for new resources to meet demand. PacifiCorp's integrated resource plan is called "Resource and Market Planning Program," or "RAMPP." Since November 1989, the Company completed five RAMPPs and an interim report (RAMPP-6). The RAMPP reports detail the background and circumstances in which these resource acquisitions were made.

PacifiCorp makes use of its least-cost plan to guide decisions regarding the acquisition of resources. Projected resource acquisition for a medium-case scenario in the 1989 RAMPP report (RAMPP-1) indicated a need for about 1,398 average megawatts ("aMW").

PacifiCorp executed four agreements related to the purchase of Cholla Unit No. 4 in September 1990. Through the transactions, PacifiCorp acquired 350 megawatts of generation resources with partially offsetting power sale to Arizona Public Service Company. PacifiCorp acquired Cholla Unit No. 4 for approximately $234 million, which includes the cost of a 37.23% share of the common facilities, the coal inventory, and the materials and supply inventories.

PacifiCorp acquired the Craig and Hayden units in April 1992. The Craig and Hayden units provide approximately 52 aMW of net resource to the Company. The total capital cost of the acquisitions and transmission obligations was approximately $280 million. PacifiCorp sought and received from the Commission certain approvals related to the Craig and Hayden units.

In January 1993, PacifiCorp and James River entered into a 20-year agreement for the development and operation of the James River Cogeneration project, which is a 50-MW high-power steam-fired generation facility in Camas, Washington. The budgeted capital cost for the project amounted to approximately $59 million.

In October 1993, PacifiCorp and U.S. Generating Company, L.P. executed a long-term Power Sales Agreement related to the Company's acquisition of the Hermiston cogeneration project. The Hermiston cogeneration project is a 470-MW natural gas-fired cogeneration facility located near Hermiston, Oregon. PacifiCorp owns 50% of the facility and accepts all of the generated power for the 50% of the project that it does not own. The Hermiston cogeneration project costs were lower than PacifiCorp's avoided costs and continued to be a low-cost resource option.

In April 1999, the Wyoming Wind Project began operating. The Wyoming Wind Project is a 41.4-MW wind-powered electric generation facility that is powered by 69 wind turbines located along the Foote Creek rim in Wyoming. PacifiCorp owns nearly 80% of the project, which provides clean, renewable electric energy. The cost of the project, without a federal income tax credit, has been show to be 65.67 mills/kWh in 1994 dollars.

Analysis of resources acquired by 1999 indicated that the Company has satisfied approximately 80% of its projected resource requirement as presented in the 1989 RAMPP report. Moreover, investigation of the sales (load) and customer data in 1999 compared with 1986 indicated an increase of 36% and 25%, respectively. The percentage share of new resources acquired between 1989 and 1999 (1,154 aMW) compared with projected load growth was about 24%. These empirical results indicate that the acquisition of resources seems to be in congruence with increases in load and customer growth.

Pursuant to the Third Supplemental Order, the Company provided information requested by Staff in order to evaluate the prudency of resources acquired since 1986. Staff evaluated the information presented with respect to whether (i) resources acquired were necessary or intended to satisfy the projected demand, (ii) the resources were acquired at least-cost compared to alternatives considered or relative to own-avoided cost of production, (iii) the acquisition of the resource unduly affected the need for DSM programs, and (iv) the acquisition process was fair. Staff concludes that the resources were acquired prudently when evaluated from a system-wide basis. However, Staff did not investigate whether the resources were acquired to satisfy increased load growth or demand of Washington customers. Therefore, it is Staff's opinion that these resources could be subject to examination in a future rate case that will determine a fair, just, and reasonable allocation of the cost burdens incurred since 1990 to Washington customers.

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CHAPTER I: INTRODUCTION

This Joint Report is prepared in accordance with the Third Supplemental Order Approving and Adopting Settlement Agreement ("Third Supplemental Order") in Docket No. UE-991832, in which the Washington Utilities and Transportation Commission (the "Commission") approved a Stipulation among PacifiCorp ("PacifiCorp" or the "Company"), Commission Staff, Public Counsel, Industrial Customers of Northwest Utilities ("ICNU"), NW Energy Coalition, and the Energy Project resolving all issues in PacifiCorp's then pending general rate proceeding.[1] The matters at issue in that proceeding included a determination of the prudence of all the resource acquisitions made by PacifiCorp since the Company's previous general rate proceeding in Washington, Cause No. U-86-02.

The Stipulation contained the following provision regarding this issue:

> Commencing within thirty (30) days after the Commission's order approving this Stipulation, the Parties will begin a process to examine the prudence of certain of the Company's resource acquisitions. The resources to be examined are those resources included in the Company's filing in this proceeding that have been acquired since the Company's last general rate proceeding in Washington, excluding resources that will no longer be in service at the end of the Rate Plan Period. This process will include a schedule that provides for informal discussions and discovery among the Parties and development of the information necessary for the Parties to evaluate the prudence of the resource acquisitions. The Company will cooperate in providing the Parties with requested information and documents in connection with the prudence examination, and will not dispute in any subsequent proceeding the authenticity of information it provides. Any information or documents produced in connection with the prudence examination may be included as part of discovery in the Company's next general rate proceeding, and will not preclude additional discovery being conducted as part of that proceeding. The schedule will provide for completion of the examination by October 1, 2001. The process will result in a joint report or findings ("Joint Report") from the Parties to the Commission as to the prudence of the identified resources. Such Joint Report

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[1] *Washington Utilities and Transportation Commission v. PacifiCorp d/b/a Pacific Power and Light Company*, Docket No. UE-991832, Stipulation (June 16, 2000) ("Stipulation").

> may include a separate statement of position by any Party with respect to any issues upon which agreement is not reached. Such Joint Report will be presented to the Commission in the Company's next general rate proceeding. Prior to such proceeding, the Company, in its sole and complete discretion, may take actions in response to such Joint Report; provided, however, that such actions will not affect the rates established pursuant to this Stipulation.[2]

The Stipulation identified the following as the resources to be included in the prudence review: Craig, Hayden, Cholla, Hermiston, and Wyoming Wind generating units.[3] In its Third Supplemental Order, the Commission added the James River generating unit acquired by PacifiCorp in 1996.[4]

In accordance with the Stipulation, the Company convened a meeting of interested parties to "begin a process to examine the prudence of certain of the Company's resource acquisitions." Commission Staff, Public Counsel, and ICNU indicated an interest in participating in the process. Thereafter, the Company provided these parties with documentation regarding each of the six resources identified in the Third Supplemental Order. This documentation included a summary of the project, a chronology of events related to the development of the project, copies of selected documents in connection with the development of the project (agreements, board presentations, quantitative analyses), and an index of remaining documents that were available for further review by the parties. Following the distribution of the materials relating to the Hermiston project, Staff provided a suggested template that would facilitate data responses for the purpose of undertaking the prudence review. For the remaining projects, the Company's presentation followed, to the extent possible, the template recommended by Staff.

In considering the prudence of the Company's acquisition of these six resources, the parties included in the Stipulation the following discussion regarding the standard to be applied:

> The standards applied by the Commission to measure prudence are generally as follows:
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> [W]hat would a reasonable board of directors and company management have decided given what they know or reasonably should have known to be true at the time they made a decision. This test applies both to the question of need and the appropriateness of the expenditures. (Cause No. U-83-54, Fourth Supplemental Order, p.p. 32-33)

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[2] Stipulation at 4.

[3] Stipulation at 4 n 5.

[4] Third Supplemental Order at 16 n 7.

> Each of the IOUs bears the burden of demonstrating the prudence of new resource acquisitions to the Commission. A demonstration of prudence includes a showing that (1) the selection of each resource was necessary and reasonable, (2) the costs of acquisition were appropriate based upon what a reasonable board of directors and company management decided given what they knew or reasonably should have known to be true at the time the decision was made, and (3) the costs were regularly evaluated. (*Notice of Termination of Notice of Inquiry*, Docket No. UE-940932, April 1998)
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> Nothing in this Stipulation prevents any Party from asserting any other consistent and applicable Commission precedent. The Company will be required to make an affirmative showing in the direct testimony and exhibits of its next general rate proceeding demonstrating the prudence of those resources acquired since its previous general rate case (Cause No. U-86-02) which it proposes to include in rates in such proceeding.[5]

This Joint Report presents the information regarding PacifiCorp's resource acquisitions in a manner that will permit application of the prudence standard. In other words, for each of the six projects identified in the Stipulation and the Third Supplemental Order, the report presents a discussion of the information bearing on the prudence determination, including (i) the need for the resource, (ii) the consideration of alternatives, (iii) the reasonableness of the resource's costs, (iv) information made available to the Company Board of Directors regarding the resource, and (v) the acquisition process.

This report is organized into five chapters. Chapter 1 explains the basis for and introduces the subject matter of this Joint Report. Chapter 2 presents a discussion of the background and circumstances in which the resource acquisitions were made, including the regulatory environment, load and resource forecasts, industry developments, and related factors affecting the Company's actions. Chapter 3 presents a critical review and analysis on each resource acquired since the last general rate case (Cholla, Craig and Hayden, James River, Hermiston, and Wyoming Wind). A summary of this Joint Report is presented in Chapter 4. References to supporting documents are provided in Chapter 5. Also included in this Joint Report are appendices A and B. Appendix A is a chronology of events related to the resource acquisitions, and Appendix B presents load forecast and customer demand information.

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[5] Stipulation at 5.

CHAPTER II: BACKGROUND AND DISCUSSION

2.1 BACKGROUND

Since the Company's rate case in 1986, various events have affected PacifiCorp's power supply and the need for power. Also, PacifiCorp completed two merger transactions within the last 14 years. The first merger occurred between PacifiCorp and Utah Power & Light Company ("Utah Power"). On September 17, 1987, PacifiCorp filed an application with the Commission for an order authorizing the merger. The Company demonstrated to the Commission that substantial economies would be gained as a result of the merger.[6] The Commission concluded that the merger and issuance of securities and assumption of obligations were consistent with the public interest and approved the merger.[7]

The second merger occurred between PacifiCorp and Scottish Power PLC ("Scottish Power") 11 years later. On December 31, 1998, PacifiCorp and Scottish Power filed an application requesting that the Commission disclaim jurisdiction over the proposed merger or, in the alternative, issue an order authorizing the proposed acquisition of control of PacifiCorp by Scottish Power. PacifiCorp, Scottish Power, Commission Staff, Public Counsel, and the Northwest Energy Coalition resolved issues related to the transaction in two stipulations. By order dated October 14, 1999, the Commission accepted the stipulations and approved the transaction.[8]

PacifiCorp initiated its integrated resource planning process to provide a formalized basis to guide future supply-and-demand decisions and to determine how to meet future energy needs at the least cost to the Company and to its customers. PacifiCorp's integrated resource planning process, conducted in accordance with WAC 480-100-251, provided the forum for considering and evaluating the background circumstances and events that necessitate the acquisition of new resources. PacifiCorp's integrated resource plan, entitled "Resource and Market Planning Program," or "RAMPP," commenced with its first report (RAMPP-1) issued in November 1989. Subsequent RAMPP reports were issued as follows:

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[6] *Re PacifiCorp Maine*, Docket No. U-87-1338-AT, Second Supplemental Order, 95 Pub Util Rep 4th (PUR) 111, 120 (1988).

[7] *Id.* at 122.

[8] *Re PacifiCorp and Scottish Power PLC for an Order (1) Disclaiming Jurisdiction or, in the Alternative, Authorizing the Acquisition of Control of PacifiCorp by Scottish Power and (2) Affirming Compliance with RCW 80.08.040 for PacifiCorp's Issuance of Stock in Connection with the Transaction*, Docket No. UE-981627, Fifth Supplemental Order Accepting Stipulations, Approving Transaction, and Granting Securities Issuance Exemption (Oct. 14, 1999).

TABLE 1. RAMPP Reports and Completion Dates	
RAMPP-1 "Planning for Stable Growth"	November 1989
RAMPP-2 "Balanced Planning for Growth"	May 1992
RAMPP-3 "Positioning for Competition and Uncertainty"	April 1994
RAMPP-4 "Flexible Choices for a Changing Market"	November 1995
RAMPP-4 Update "1997 IRP Report"	December 1996
RAMPP-5 "Resource and Market Planning Program"	December 1997
RAMPP-6 "Interim Report"	December 1999

These reports provide a description of the background and circumstances in which these resource acquisitions were made. Selected issues presented in RAMPP reports are summarized below.

2.2 RAMPP-1

According to RAMPP-1, the context suggested "a substantial energy surplus for most of the 1980s, both for the Company and the Pacific Northwest region as a whole."[9] Included in the findings of RAMPP-1 were the following:

- Pacific Power and Utah Power have a broad range of flexible and efficient options that can be used to maintain an efficient balance between demand and supplies.

- A broad range of supply-and-demand alternatives have been identified that can be deployed to meet the range of possible futures, with costs lower than construction of new, large baseload generating facilities and many at costs at or below current system average costs. These sources are likely to be sufficient for future demand growth in the most probable range of economic conditions.

- Results of RAMPP studies show that the Company's portfolio of new sources can meet load growth in the high range without a major new thermal generation construction program.

[9] RAMPP-1 at 7.

- With respect to demand-side management ("DSM"), programs capable of deriving approximately 400 to 600 average megawatts ("aMW") of energy efficiencies in the Company's customer base appear to have relatively low costs when compared with conventional coal-fired generation, on a total life-cycle cost basis.

- Economical purchases of up to 800 aMW are likely to be available from Bonneville Power Administration ("BPA") and from other utilities in the Rocky Mountain, desert Southwest, and Canadian areas of the interconnected West. Significant economical cogeneration potential exists in the Company's customer base, amounting to about 400 aMW.

- The marketplace can be expected to provide a significant share of future resources in the form of purchases from other utilities and cogeneration. At the same time, cogeneration potential could represent bypass risk. A loss of customers, and thus lost sales and revenues, due to increasing competition could also have the effect of stagnant sales and a significant price shock to remaining customers. Cost control, price competitiveness, and value-added services are appropriate strategies to manage this risk.[10]

2.3 RAMPP-2

RAMPP-1 was completed during the first year of operation for the system that was created by the Pacific Power-Utah Power merger, and focused on meeting energy needs. The RAMPP-2 planning effort paid closer attention to emerging capacity needs as well. Major developments that were considered as part of the RAMPP-2 analysis included the following:

- Growth in electricity demand was on the high side of the RAMPP-1 forecast range. Actual electricity usage since the publication of RAMPP-1 increased at a rate of 2.8% in 1990 and 1.2% in 1991, for an average of 2.0%. The RAMPP-1 report predicted a range of 0.5% annual average load growth over the next 20 years at the low end, 1.6% in the medium case, and 2.6% in the high case.

- PacifiCorp completed a series of multifaceted agreements for resource acquisitions:

- One was with Arizona Public Service Company ("APS") for wholesale power sales, seasonal exchanges, transmission rights, and generation use and planning. The Company acquired 350 megawatt ("MW") of generation resources from the transaction, with a partially offsetting power sale to APS. The APS agreements added to PacifiCorp's resource base, captured seasonal diversity efficiencies, and extended the length of time within which the Company will have sufficient existing resources to meet customer needs.

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[10] RAMPP-1 at 7-10.

- In a separate transaction, PacifiCorp acquired 243 MW of the Colorado-Ute Electric Association ("Colorado-Ute") generation plant. Under the agreement among PacifiCorp, Public Service Company of Colorado ("PSCo"), and Tri-State Generation and Transmission Association ("Tri-State"), the Company purchased a share of the facilities of the bankrupt Colorado-Ute and acquired related transmission rights. PacifiCorp also entered into a 176-MW long-term power sale to PSCo and a seasonal exchange with Tri-State. Like the APS agreements, the Colorado-Ute transaction provides the Company with additional resources to meet customer needs.

- Congress amended the Clean Air Act, although the impact on PacifiCorp is expected to be small because the Company's generating plants burn low-sulfur coal and most already have sulfur dioxide emission controls. The Company has sufficient SO_2 emissions allowances to operate its system effectively and continue to grow as needed.[11]

2.4 RAMPP-3

In RAMPP-3, the Company reported on its successful implementation of the RAMPP-2 action plan, including the pursuit of demand-side, renewable, peaking, and cogeneration resources; system efficiencies; and RAMPP improvements. The Company reported that it was on schedule in implementing the demand-side programs specified in the RAMPP-2 action plan and that two wind projects were in the siting process. The Company met some of its increased capacity needs through a capacity agreement with another utility and commenced construction of a cogeneration project, the James River facility.

Major developments that were considered as part of the RAMPP-3 analysis included the following resource decisions and certain other events that were described as "outside the company's control" yet affecting resource planning:[12]

- PacifiCorp signed a contract to acquire electricity from a 474-MW natural gas cogeneration plant in Hermiston, Oregon. A RAMPP-3 sensitivity tested its benefits to the system.

- PacifiCorp entered into a 10-year agreement with Southern California Edison ("SCE") to purchase low-cost capacity. The SCE agreement delayed the company's schedule for construction of gas turbines and provides flexibility to meet winter loads.

- Among major events "affecting the Company's business environment" were the following:

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[11] RAMPP-2 at 6-7.

[12] RAMPP-3 at 9-17.

- Addressing disincentives that can occur with the acquisition of demand-side resources compared to supply-side resources.

- Passage of the Energy Policy Act of 1992, which accelerated the transition toward an increasingly competitive energy marketplace. Major features of the act are the establishment of exempt wholesale generators and greater transmission access.

- Administrative rules for the Clear Air Act amendments.

- Competitive forces are relevant both for wholesale electricity markets and at the retail level. Passage of the Energy Policy Act of 1992 increased the forces of competition in the industry. For PacifiCorp, with almost one-half of its retail sales to industrial customers, competition is an immediate reality. Increasingly, retail customers pursue low-cost options for electric energy services. Alternatives such as self-generation, fuel switching, moving to other providers like public power, relocating or expanding to other sites, cogeneration, bypass, and new technology are growing.

- PacifiCorp's retail load growth in 1992 energy sales was 1.1% actual, 2.6% temperature-adjusted. For 1993, actual load growth in energy sales was 2.1%, 1.0% temperature-adjusted.[13]

2.5 RAMPP-4 AND RAMPP-5

RAMPP-4 contained a considerable discussion about PacifiCorp management's perception at the time of the energy marketplace and the effect of the electric utility industry on the Company's view of planning. RAMPP-4 included a discussion of the following "key perceptions" about future trends in the industry:

- Competition for service to PacifiCorp customers will continue to intensify with more and more choices available to customers. PacifiCorp believed at the time that the electric industry was in transition from a regulated monopolistic environment to a competitive market and that retail wheeling would exist in some form throughout the Company's service territory within five years. RAMPP-4 report stated, "As the market becomes more efficient, more power will be available, and prices will drop. PacifiCorp believes that the West will have excess power supplies for at least 5 to 7 years, and possibly 10, on the basis of the level of existing capacity at the time and the prospects for new generation."

- RAMPP-4 cites the California Public Utility Commission hearings on restructuring the electric utility industry in the state.

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[13] RAMPP-3 at 9-15.

- The Utah Public Service Commission held three public meetings to address restructuring in the electric utility industry.

- Most states are now considering, either through legislation or regulatory proceedings, some form of retail wheeling or regulatory restructuring.

- Over the next five years, state regulation will continue to change to reflect a more competitive environment.

- Several of the states served by PacifiCorp, including California, Utah, and Montana, are conducting proceedings on regulatory change and the restructuring of the electric utility industry.

- Alternative forms of regulation will become critical to successful electric utilities.

- Full open access to the nation's transmission system will be in place within a few years.

- The conditions Federal Energy Regulatory Commission ("FERC") imposed on the Utah Power/Pacific Power merger reduced PacifiCorp's control of its own transmission system, and FERC is expanding those provisions and rapidly extending them to all utilities.

- FERC has been requiring comparability tariffs that would give transmission access to third parties at prices, terms, and conditions comparable to those the owning utilities apply to themselves.

- FERC's [Notice of Proposed Rulemaking ("NOPR")] on transmission access replaces this piecemeal approach with a systematic opening of the system to all utilities.

- Electric utilities will be able to increasingly rely on power purchases in the wholesale markets to meet their power needs. Because of changes occurring in transmission and in the power generation business, PacifiCorp expects to be able to increasingly rely on the wholesale market to meet its power needs, both from the nonfirm market and from longer-term contracts. Power purchases give the Company more flexibility in the way it can meet the energy needs of its customers. If the price of power on the wholesale market is very attractive and other conditions are right, the nonfirm market could allow the Company to delay other resource acquisitions. Similarly, longer-term contracts on the wholesale market can sometimes provide more cost-effective solutions to system needs than building a new power plant.

- Increasing involvement in the wholesale market will mean greater rewards as well as greater potential risks. As the wholesale market is becoming more efficient, prices and margins are falling. In the past, PacifiCorp has successfully used margins from wholesale revenues to reduce retail prices. This will become increasingly difficult as wholesale prices and margins decline.

- The trends identified above will lead to increased risk in the Company's business environment.

- As the electric utility industry evolves into a competitive market, the need for detailed resource planning under regulatory commission oversight will decrease.

- The planning horizon will shrink as the pace of changes increases in the marketplace.

- Society will have a more difficult time achieving its social and environmental objectives through energy providers as competition imposes tighter cost constraints.[14]

Action items included in the RAMPP-4 action plan included the following:

- Demand-side resources: Achieve 23 aMW of installed cost-effective savings by 1996, 25 aMW by 1997, and 28 aMW by 1998.

- Peaking: PacifiCorp needs no new winter peaking resources until 2003, although the system may need summer peaking resources beginning in 2002.

- Gas-fired resources: PacifiCorp does not need new baseload resources until 2003 or later.

- Preparing for the future: Implement cost-effective system improvements to the generation, transmission, and distribution systems; pursue low-cost activities that will increase the Company's knowledge about renewable resources; and continue to evaluate clean coal technologies.[15]

The RAMPP-4 report was updated in a December 1996 report that referred to six major events in 1996 that affected planning: FERC Order Nos. 888 and 889, two outages that affected much of the western United States, the beginning of the process to form a small number of Independent System Operators ("ISOs") to operate large portions of the western transmission system, negotiation of emission reductions at the Centralia plant, the Northwest

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[14] RAMPP-4 at 3-17.

[15] RAMPP-4 at 18, 181-83.

Comprehensive Review, and California restructuring.[16] The RAMPP-5 report refers to a number of significant events in 1997 that were a continuation of issues from 1996. These include the following:

- Opening the entire state of California to direct access beginning January 1, 1998.
- Increasing activity on the transition to an open competitive marketplace. RAMPP-5 refers to open access coming to increasing portions of the Company's service territory, including California in 1998 and Montana shortly thereafter.
- Greater resolution of the FERC NOPR rules in Order Nos. 888 and 889.
- Continued progress on IndeGO, an independent system operator ("ISO") for the regional transmission network in the Northwest.
- Resolution of the Centralia plant's emission rules through selection of an option to build two wet-limestone scrubbers.
- Increased concern about global warming.[17]

2.6 RAMPP-6

On December 31, 1999, PacifiCorp presented a RAMPP-6 interim report that referred to the "pace of change in the electric industry." Included are references to the following:

- In December 1998, PacifiCorp announced a merger with Scottish Power, which was completed at the end of November 1999.
- During 1999, the Oregon legislature passed electric industry restructuring legislation that provides for direct access to third-party energy service providers and a portfolio of electric service options for smaller customers, in addition to the traditional cost of service-based service. The legislation also created a system-benefits charge to be paid by customers of PacifiCorp to fund demand-side programs such as funding low-income weatherization, encouraging renewable development, and supporting conservation efforts in education service districts.
- Another major change in the electric utility industry in the West is the effort by the BPA to replace the Residential Exchange program for delivering federal power benefits to qualifying Investor Owned Utility ("IOU") residential and small-farm customers with a subscription program.[18]

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[16] RAMPP-4 Update at 7-12.

[17] RAMPP-5 at 4-18.

[18] RAMPP 6.

The Company also reported in the RAMPP-6 interim report that its Wyoming wind project at the Foote Creek rim began generating electricity in fall 1998. The project has a total capacity of 41.4 MW, and PacifiCorp owns 80% of the project. (Eugene Water & Electric Board ("EWEB") owns the remainder.) The Company did not acquire new resources other than Wyoming Wind.

Appendix B sets forth historical information regarding customer numbers, class and load by state, and forecasted customer loads by state and class.

2.7 SUMMARY OF STAFF'S REVIEW

Staff has reviewed the key findings of the RAMPP reports. Issues discussed in the RAMPP reports are raised here because utility companies are expected to make use of outputs from their least-cost resource optimization algorithm in guiding their decision with respect to identification, evaluation, and acquisition of generation resources. A review of RAMPP reports since 1989 indicated that the Company needed about 1,400 MW of generation resources by 2008. Furthermore, the reports indicated a need to acquire these resources so that the Company satisfies resource diversity and compliance with environmental regulations. Nonetheless, in Staff's view, these RAMPP results are not expected to provide the necessary and sufficient basis for evaluation of prudency. The results from these reports are used along with additional information that was requested from the Company in determining prudency of resource acquisitions.

CHAPTER III: CRITICAL REVIEW AND ANALYSIS

3.1 INTRODUCTION

As noted, the integrated resource planning ("IRP") process documents the internal and external processes used by PacifiCorp to analyze future load growth and the need for new resources to meet demand.[19] DSM resources were considered as part of the IRP process. Also, in 1991, the Company completed a Request for Proposals ("RFP") to acquire additional resources. However, resources were also acquired without the aid or necessity of an RFP.

3.1.1 Consideration of Demand-Side Resources

PacifiCorp's integrated resource planning process includes an analysis of DSM resources in addition to supply-side resources. DSM resources include implementing conservation measures and increasing the energy efficiency of new and existing buildings.

The level of demand-side resources varies with the load forecast, because estimates of potential savings depend on the forecast used and on detailed end-use information. The amount of electricity that can be saved through energy efficiency measures is directly tied to the number of homes, businesses, and industries served. Resource acquisition opportunities rarely involve a simple numerical comparison of one resource to another. Instead, such opportunities represent a chance to achieve potential benefit from the diverse load and resource characteristics within the region and with other regions. Generally, the RAMPP model forecasts first select demand-side resources to fill the Company's resource needs and then select the next most cost-effective resource. Adding demand-side resources reduces the remaining energy and capacity needs that must be met by other resources.

Demand-side resources are not affected by the acquisition or development of any particular resource, but the lower costs of supply-side resources affect the level of DSM. For example, RAMPP-4 added less DSM than RAMPP-3 at the medium DSM level due to two primary changes: lower system needs and lower costs of new supply-side resources that were competitive with DSM. The lower costs of new supply-side resources reduced the level of cost-effective DSM from 23 aMW in RAMPP-4 to 15.7 aMW in RAMPP-5.

3.1.2 The RFP Process

As a general principle, a regulated utility should explore low-cost potential power purchases or resources consistent with its least-cost resource plan. The major goal of a utility's resource plan should be to acquire resources that will satisfy the electrical needs of its customers at a minimum (least) cost. In addition to prices, factors such as location, environmental concerns, financial risks, fuel supply, and diversity and benefits such as transmission access and secondary market access may influence the decision-making process regarding the acquisition of resources.

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[19] RAMPP-5 at 1.

On October 1, 1991, PacifiCorp released an RFP for 50 MW of resources that would produce electricity or savings for at least 10 years but not more than 20 years. The 1991 RFP marked the first time that PacifiCorp used an RFP in resource acquisition. The Company solicited both demand-side and supply-side resources. Supply-side proposals were for a project of not less than 100 kilowatts ("kW"). Proposals were requested system-wide and were limited to qualifying facilities and independent power producers, which represented the universe of available suppliers at the time of the RFP. The RFP process was consistent with guidelines provided by regulations and orders of state commissions, including the Commission, the Public Utility Commission of Oregon, and the Utah Public Service Commission, which required the Company to solicit supply-side proposals from qualifying facilities only. The RFP was consistent with the competitive bidding rule at the time. During 1992 and 1993 the Company evaluated approximately 20 projects to meet retail load.[20]

3.2 ACQUISITION OF CHOLLA UNIT NO. 4

In September 1990, PacifiCorp and APS executed four agreements related to PacifiCorp's purchase of Cholla Unit No. 4 (the "Cholla Unit No. 4 Acquisition"). The contracts included (1) the purchase and operation of Cholla Unit No. 4, a generating plant; (2) the sale and exchange of firm power; (3) cooperative development of transmission facilities; and (4) exchange of transmission services. Through the transactions, PacifiCorp acquired 350 MW of generation resources with a partially offsetting power sale to APS. APS also granted PacifiCorp 350 MW of transmission rights for no extra fee. In addition, the agreements provided for the possible future installation of 150 MW of new combustion turbine capacity.

PacifiCorp and APS have reciprocal use of Cholla Unit No. 4. Under a long-term power transactions agreement, PacifiCorp sells firm power to APS during the summer peak season, and APS makes firm supplemental energy available, which PacifiCorp may purchase.

PacifiCorp also was granted the rights to develop and/or use up to 650 MW of combustion turbine capacity. Under the agreements, PacifiCorp is entitled to secondary use of the existing combustion turbines and also may construct new combustion turbines, which would be jointly developed by PacifiCorp and APS and operated by APS.

The transactions add to PacifiCorp's resource base, capture seasonal diversity efficiencies, and extend the length of time within which the Company will have sufficient existing resources to meet customers' needs.

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[20] A copy of the report concluding this process, "Evaluation Process and Results of Supply Side Resources," is included as Reference Document A.8.

Supporting document references regarding the acquisition of Cholla Unit No. 4 include:

- October 11, 1990 Letter Agreement (C.1)
- Asset Purchase and Power Exchange Agreement (C.2)
- Cholla Unit 4 Operating Agreement (C.3)
- Long-Term Power Transactions Agreement (C.4)
- Transmission Agreement (C.5)
- RAMPP-2 "Balanced Planning for Growth" Excerpts (A.2)
- February 25, 1993 Evaluation of PacifiCorp's Acquisition of Facilities from Arizona Public Service Company and Colorado-Ute Electric Association, Volumes I and II, by Resource Management International, Inc. ("RMI Study") (C.14)
- Indexed documents in Attachment W under category entitled "Contract Negotiations" (C.15)

3.2.1 Demand for Cholla Unit No. 4

3.2.1.1 Results from RAMPP

The need for Cholla Unit No. 4 was established in RAMPP. In 1989, RAMPP-1 investigated several alternative load forecasts and expansion scenarios. (*See* Table 2)

As reflected in RAMPP-1, the "Purchases and Contract Rights" included purchases from existing Western System Coordinating Council ("WSCC") generation (potential lost opportunities) or new independent sources. The Cholla Unit No. 4 Acquisition, which enabled PacifiCorp to obtain approximately 210 aMW of resources until APS purchases increased to 350 MW, and 140 aMW thereafter, fits into this category of need. This acquisition falls within the medium case forecast reported in the Company's least-cost plan.

Moreover, in its evaluations, PacifiCorp assumed that the equivalent of approximately one-half of the aMW of capacity available after sales to APS would be sold to others. That is, the net resource assumed available to PacifiCorp would be approximately 105 aMW until sales to APS increased to 350 MW, and 70 MW thereafter.

With respect to timing, RAMPP-1 determined that, for the medium forecast, 115 aMW of Purchases and Contract Rights would be required by 1995. RAMPP-1 also projected that the need for these resources would increase to 215 aMW by 2005 and to 353 aMW by 2008.[21] Thus the net aMW of capacity assumed available to the Company corresponded to the RAMPP-1 estimated timing.

Supporting document references regarding RAMPP results include:

- RAMPP-1 "Planning for Stable Growth" Excerpts (A.1)
- RAMPP-2 "Balanced Planning for Growth" Excerpts (A.2)

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[21] RAMPP-1 at 38-40.

- RMI Study (C.14)
- Indexed documents in Attachment W under category entitled "Need for Power/Resource Planning" (C.15)

3.2.1.2 Impact on DSM Resources, System Optimality

Cholla Unit No. 4 has been operating at a higher output than initially projected. In September 1990, the MW rating for Cholla Unit No. 4 was rated at 350 MW. Shortly thereafter, the Company tested Cholla Unit No. 4 and determined that the generator could be rated as high as 390 MW. PacifiCorp sought and received the authority to operate Cholla Unit No. 4 at the higher rating. The resultant capacity cost was decreased to $599 per kW from $667 per kW before the upgrade.

RAMPP-5 projected that Cholla Unit No. 4 capacity would decrease to 380 MW in 1998 through 2017. This decrease in capacity is related to the decision to postpone indefinitely the installation of combustion turbines as a result of the changing power markets, but is still higher than the original 350-MW output rating.

Supporting document references related to the impact of DSM resources and system optimality include:

- RAMPP-2 "Balanced Planning for Growth" Excerpts (A.2)
- RAMPP-3 "Positioning for Competition and Uncertainty" Excerpts (A.3)
- RAMPP-4 "Flexible Choices for a Changing Market" Excerpts (A.4)
- RAMPP-5 "PacifiCorp Resource and Market Planning Program" Excerpts (A.6)
- RMI Study (C.14)

3.2.2 RFPs and the Resource Acquisition Process

During the time that PacifiCorp negotiated and evaluated the Cholla Unit No. 4 Acquisition, there was no formal requirement that PacifiCorp issue an RFP. According to PacifiCorp, the Company pursued the Cholla Unit No. 4 Acquisition because it represented a new resource option with low-cost potential that was consistent with the Company's least-cost plan.

Supporting document references regarding the RFP and acquisition process include:

- PacifiCorp's 1991 Request for Proposals (A.8)
- RAMPP-2 "Balanced Planning for Growth" Excerpts (A.2)
- RMI Study (C.14)

At the time Cholla Unit No. 4 became available, comparable alternatives included San Juan Unit 3 and San Juan Unit 4. An evaluation of these and other alternatives showed that the costs for the Cholla Unit No. 4 Acquisition compared favorably to other baseload resource acquisition projects developed by other utilities.

Specifically, the City of Anaheim, California bought 50 MW of capacity from San Juan Unit 4 for approximately $1,140 per kWh. Fuel and operations and maintenance ("O&M") costs for San Juan Unit 4 were approximately $25 per MWh. At the time PacifiCorp acquired Cholla Unit No. 4, other publicly owned utilities in California completed a transaction to acquire 200 MW from San Juan Unit 3. That project cost approximately $930 per kW, and fuel and O&M costs were approximately $25 per MWh. In comparison, the estimated 1991 total annual cost of energy from Cholla Unit No. 4 was approximately $30 per MWh at 350 MW and $29 per MWh at 390 MW. On a total-cost basis, the San Juan Unit 3 project costs for less capacity are 28 to 31 percent higher than the Cholla Unit No. 4 Acquisition costs.

The costs of the Cholla Unit No. 4 Acquisition compared favorably to alternatives discussed in the RAMPP reports. In the RAMPP-1 report, the costs for comparable alternatives ranged from approximately $35 per MWh to approximately $70 per MWh. In RAMPP-2, the costs for comparable alternatives ranged from approximately $35 per MWh to $66 per MWh.[22]

In a subsequent independent evaluation conducted by Resource Management International, Inc. (entitled "Evaluation of PacifiCorp's Acquisitions of Facilities from Arizona Public Service Company and Colorado-Ute Electric Association" or "RMI Study"), the acquisition costs of Cholla Unit No. 4 also compared favorably. The RMI Study found that the Cholla Unit No. 4 costs compared to the cost of resources from RAMPP-1 was "considerably less costly than the other resources on a cost per kW basis and on a total cost basis."

Supporting document references related to the assessment and evaluation of alternatives include:

- RAMPP-1 "Planning for Stable Growth" Excerpts (A.1)
- RAMPP-2 "Balanced Planning for Growth" Excerpts (A.2)
- RMI Study (C.14)
- Indexed documents in Attachment W under category entitled "Alternatives" (C.15)

3.2.3 Decision-Making Process

Cholla Unit No. 4 was purchased for approximately $234 million, which includes the costs of a 37.23% share of the common facilities, the coal inventory, and the materials and supply inventories. The total capital costs of the Cholla Unit No. 4 Acquisition were estimated to be between $350 million to $370 million depending on the transmission facilities ultimately acquired and the portion of transmission costs attributable to the APS transactions.[23] The RMI Study reported that estimated costs and revenues appeared reasonable and were consistent with historical data for Cholla Unit No. 4.

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[22] RMI Study vol I at 2-3, 13.

[23] RMI Study vol I at 2-3.

For comparison purposes, the RMI Study assumed that the Cholla Unit No. 4 cost PacifiCorp $667 per kWh based on a rating of 350 MW, or $599 per kWh based on a rating of 390 MW with associated fuel and O&M costs of approximately $21 per MWh in 1991. Based on these factors, the assumptions, projected revenues and costs used in PacifiCorp's analyses of the Cholla Unit No. 4 Acquisition were consistent with results of its least-cost plan.

In addition, the power sales to APS and other parties allow PacifiCorp to defray a significant portion of the costs associated with the acquisitions. PacifiCorp's ability to increase the net rating of Cholla Unit No. 4 to 390 MW may also provide a beneficial economic impact to the Company. The capacity cost of Cholla Unit No. 4 was reduced from $667 per kW to $599 per kW with the approval of a 390 MW rating.[24] Based on RAMPP-2, these resource costs are lower than the expected costs for other resources on a cost-per-kW and a total-cost basis.

The results of the PacifiCorp analyses of the Cholla Unit No. 4 acquisition indicate that the acquisition could benefit PacifiCorp's retail customers because the cost of power to PacifiCorp is less than the cost of similar amounts of energy purchased at PacifiCorp's avoided cost.[25]

Supporting document references regarding decision criteria and analysis of project costs include:

- Asset Purchase and Power Exchange Agreement (C.2)
- PacifiCorp Analysis of APS Transactions (C.7)
- PacifiCorp Avoided Cost Analysis of Cholla Unit 4 Acquisitions (C.8)
- RAMPP-2 "Balanced Planning for Growth" Excerpts (A.2)
- RMI Study (C.14)
- Indexed documents in Attachment W under category entitled "Analysis of Project Costs" (C.15)

The Cholla Unit No. 4 Acquisition represents one of several major resource acquisitions the Company made since it began its integrated resource planning process. As part of its decision-making process, RAMPP-1 identified the potential for generation facilities to meet PacifiCorp's generating needs. Cholla Unit No. 4 met some of those needs. The Cholla Unit No. 4 Acquisition helps the Company and APS to take advantage of the diversity in their loads and generating facilities.

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[24] RMI Study vol II at 16.

[25] Reference Document I presents the PacifiCorp spreadsheets evaluating the Cholla Unit No. 4 Acquisition. Reference Document J presents the PacifiCorp avoided-cost information, reflecting avoided costs before and after the Cholla Unit No. 4 and Colorado-Ute acquisitions.

On September 14, 1990, a presentation to the PacifiCorp Board of Directors was made regarding the purchase of generation assets from APS.[26] The presentation included:

- Description of generation assets purchased from APS (p. 1)
- Description of transmission rights under the APS agreements (p. 2)
- Description of the power sales and transactions between PacifiCorp and APS (p. 3)
- Discussion of benefits to PacifiCorp from the transactions (p. 4)
- Discussion of benefits to APS from the transactions (p. 5)
- Discussion of joint benefits to PacifiCorp and APS from the transactions (p. 6)
- Presentation of proposed generating facilities transactions (p. 7)
- Map showing proposed transmission arrangements (p. 8)
- Graph showing amount and annual shaping of proposed long-term power transactions (p. 9)

On February 20, 1991 a presentation was made to the PacifiCorp Board of Directors entitled "Loads & Resources, The New Balancing Act."[27] The presentation included:

- Description of the balance between supply and demand, and impact of APS acquisitions (p. 1)
- Tables showing historical retail sales growth rates (p. 2)
- Graph showing current forecast of loads and resources, including impact of APS transactions (p. 3)
- Analysis of outlook for 1991, with and without APS transactions (p. 4)
- Discussion of "new supply building blocks" (p. 5)
- Table showing costs for coal-fired generation, including Cholla Unit No. 4 (p. 6)
- Graphs showing wholesale sales share of revenues (p. 7)
- Table showing "new wholesale market potential" (p. 8)
- Table describing existing firm sales (p. 9)
- Map showing location of loads and resources (p. 10)
- Graph showing record loads for 1990 (p. 11)

In its decision-making process, the Company conducted a transaction study that it presented to the Public Service Commission of Utah. The study analyzed the total revenue requirements for the Cholla Unit No. 4 Acquisition, including, among others, O&M expenses, fuel expenses, depreciation costs, and capital addition expenses.

PacifiCorp received regulatory approval for the transaction from the Arizona Corporation Commission and FERC. The agreements became effective in July 1991.

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[26] Reference Document C.9.

[27] Reference Document C.10.

Supporting document references related to the decision-making process include:

- September 14, 1990 Presentation to Board of Directors (C.9)
- February 20, 1991 Presentation to Board of Directors (C.10)
- July 11, 1991 Arizona Corporation Commission Order, Docket No. U-1345-90-269 (C.13)
- RAMPP-1 "Planning for Stable Growth" Excerpts (A.1)
- RAMPP-2 "Balanced Planning for Growth" Excerpts (A.2)
- RMI Study (C.14)
- Indexed documents in Attachment W under category entitled "Need for Power/Resource Planning" (C.15)
- Indexed documents in Attachment W under category entitled "Analysis of Project Costs" (C.15)
- Indexed documents in Attachment W under category entitled "Other Regulatory Proceedings" (C.15)

3.2.4 Staff's Assessment of Prudency of Cholla Unit No. 4

The basis for the determination of the need for additional load stems from comparison of the availability of existing resource mix with projected demand for additional load. Models used in preparation for least-cost plans are intended to identify the gap between the demand for and supply of resources over a long-term period. The outputs from these models facilitate the decision-making process of utilities with respect to the acquisition of additional resources.

PacifiCorp prepared its first integrated resource plan, also called "Resource and Market Planning Program" or "RAMPP," in 1989. The optimization routine was run for different cases of scenario, of which the medium case was utilized in determining the need for resources. Projected demand for new resources in the RAMPP-1 report indicated that the Company needed 115 aMW of power by 1995.

In determining the mix of resources, the model included Purchases and Contract Rights from existing WSCC generation or new independent sources. When the Company decided to acquire new resources, there was no formal requirement that PacifiCorp issue an RFP. Therefore, the fairness of an RFP process cannot be assessed.

Alternative sources of power in RAMPP-1 and -2 indicate a price of $35 to $70 per MWh. The costs of acquiring Cholla Unit No. 4 compared to alternatives such as San Juan or building new coal-fired generation such as Hunter were less by about $40/MWh (levelized). This cost is about 30% less than other comparable projects. Thus Cholla Unit No. 4 was relatively cost-effective compared to other base load resource considered by the Company.

PacifiCorp and APS entered into reciprocal use of Cholla Unit No. 4 in which the former sells firm power to the latter during the summer peak season, and APS makes firm supplemental energy available that PacifiCorp may purchase. PacifiCorp was also granted the rights to develop and/or use up to 650 MW of combustion turbine capacity. The nature of the transactions add to PacifiCorp's resource base, capture seasonal diversity efficiencies, and extend the length of time within which the Company will have sufficient existing resources to meet customers' needs.

Staff believes that Cholla was acquired prudently only from the perspective that system load justified acquisition of new resources about the size of Cholla, albeit not Cholla in particular. However, in Staff's view, it is difficult to determine whether or not the project was cost-effective compared to all available alternatives, because there was no open bidding when the Company acquired this resource.

3.3 ACQUISITION OF CRAIG AND HAYDEN GENERATING UNITS

In April 1992 PacifiCorp, PSCo, and Tri-State finalized a joint plan to acquire the assets of Colorado-Ute (the "Colorado-Ute Acquisition"). Under the acquisition PacifiCorp acquired 243 MW of existing coal-fired thermal resources representing 82.5 MW from each of Craig Units 1 and 2 (165 MW), a 45 MW share of Hayden Unit 1, and a 33 MW share of Hayden Unit 2. The transaction also transferred to PacifiCorp two-thirds of Colorado-Ute's interest in the Trapper Coal Mine, which is the primary source of coal supply for Craig Units 1 and 2, and a 50 MW winter/summer power exchange with Tri-State. This kilowatt-hour for kilowatt-hour exchange provides capacity and energy for the Company in the winter and, conversely, for Tri-State in the summer.

The total capital cost of the acquisitions and transmission obligations was approximately $280 million. To offset the costs of the acquisition, PacifiCorp arranged for the sale or exchange of capacity between PacifiCorp and the parties from sources other than revenues from retail customers.

On October 15, 1991, PacifiCorp filed with the Commission a petition seeking certain approvals in connection with the Colorado-Ute acquisitions.[28] (Docket No. UE-911186.) Specifically, the Company sought to value the acquired resources at PacifiCorp's full acquisition cost. The Company further proposed certain accounting treatment in connection with the full cost of the acquisitions, including the acquisition premium. In support of this petition, the Company submitted the pre-filed testimony and exhibits of witnesses Dennis P. Steinberg, Anne E. Eakin, and Gregory N. Duvall.[29]

In an order issued January 15, 1992, the Commission granted the Company's petition, as amended. In so doing, the Commission reserved for a subsequent rate proceeding the issue of "[t]he allowance of acquisition adjustments for ratemaking purposes" and "made no determination regarding the merits of the proposed acquisition or the amount of PacifiCorp's investment that may be included in rate base in a future proceeding."[30]

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[28] A copy of this petition is Reference Document B.5.

[29] Reference Documents B.6, B.11, and B.7, respectively.

[30] Docket No. UE-911186, Order Granting Petition as Amended at 3-4. A copy of this order is Reference Document B.12.

Supporting document references for the acquisition of the Craig and Hayden generating units include:[31]

- Asset Purchase Agreement (B.1)
- PacifiCorp's Petition to the WUTC (B.5)
- Testimony and Exhibits of Dennis P. Steinberg in Support of Petition (B.6)
- Testimony and Exhibits of Gregory N. Duvall in Support of Petition (B.7)
- Testimony and Exhibits of Anne E. Eakin in Support of Petition (B.11)
- WUTC Order Granting Petition as Amended (B.12)
- RMI Study (B.13)
- Indexed documents in Attachment V under category entitled "Contract Negotiations" (B.14)
- Indexed documents in Attachment V under category entitled "Washington Regulatory Proceedings" (B.14)
- Indexed documents in Attachment V under category entitled "Other Regulatory Proceedings" (B.14)

3.3.1 Demand for Craig and Hayden Generating Units

3.3.1.1 Results from RAMPP

The acquisition of Craig Units 1 and 2 and Hayden Units 1 and 2 followed results obtained in RAMPP-1. In 1989, RAMPP-1 investigated several alternative load forecasts and expansion scenarios.[32] The medium forecast specified that, between 1989 and 2008, quantities of new resources would be required as follows:

TABLE 2. Forecasted Resource Requirements from RAMPP-1

Resource Type	Average MW
Purchases and Contract Rights	353
Energy Efficiency	380
Cogeneration	280
Firming Strategy	289
System Efficiency	96
Total	1,398[33]

As reflected in RAMPP-1, the Purchases and Contract Rights included purchases from existing WSCC generation (potential lost opportunities) or new independent sources. Of the total 243

[31] For a complete list of references, see Chapter V: References.

[32] RAMPP-1.

[33] RAMPP-1 at 38-40.

MW that the company acquired from the Craig and Hayden plants, 176 MW was resold, leaving 67 MW at a capacity factor of 78%. Thus the acquisitions of Craig Units 1 and 2 and Hayden Units 1 and 2, which provide approximately 52 aMW of net resource to PacifiCorp, fall within the resource requirement forecasted in PacifiCorp's RAMPP-1 least-cost plan.

At the time of the acquisitions under the joint plan, PacifiCorp had already acquired net resources from Cholla Unit No. 4 of approximately 105 aMW. With the addition of the 52 aMW due to the joint plan acquisitions, the total of Purchases and Contract Rights capacity increased to 157 aMW (until such time as sales to APS were anticipated to increase, and to 122 MW thereafter).

With respect to timing, according to the medium forecast under RAMPP-1, 115 aMW of Purchases and Contract Rights would be required by 1995. RAMPP-1 also projected that the need for these resources would increase to 215 aMW by 2005 and to 353 aMW by 2008. The MW available from the Colorado-Ute Acquisition, combined with other acquisitions such as Cholla Unit No. 4, corresponded well to this estimated timing, particularly after increased sales to APS.

The testimony and exhibit of Gregory N. Duvall states as follows with respect to the demonstrated need for the Colorado-Ute Acquisition:[34]

> The four load forecasts shown in [Reference Document B.10] were developed as part of the Company's ongoing integrated resource planning process. They represent the high, medium-high, medium-low, and low load growth scenarios that will be included in the [RAMPP-2] study that will be available in draft form at the end of this year.
>
> [Reference Document B.10] shows that the net Colorado-Ute resource is required to maintain reasonable capacity reserves. If the Company experiences high to medium-high load growth during the next few years, additional capacity resources will need to be acquired. Under medium-low load growth conditions, the net Colorado-Ute resource will provide reasonable capacity reserve levels until about 1997.
>
> With regard to energy, the net Colorado-Ute resource provides the Company with sufficient energy resources through 1993 to 1996 if high to medium-high load growth is experienced. If medium-high to medium-low growth is experienced, energy

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[34] Reference Document B.7.

> resources will be sufficient through the 1996 - 1999 time frame.[35]

The testimony and exhibit of Dennis P. Steinberg also explains the need for the resource:

> Among the Company's attractive supply alternatives, RAMPP 1 highlighted the availability of energy and capacity from existing generating resources of the Rocky Mountain and Desert Southwest utilities (RAMPP 1 vol. 1, p. 29, RAMPP 2 vol. 2, pp. 73, 74). Purchases and Contractual Rights made up a significant fraction of the RAMPP 1 New Source Portfolio (RAMPP 1 Vol. 1, pp. 31-33). In the medium to high range of cases, this category contributed from 350 to 700 average megawatts of energy to the total resource portfolio, with an estimated total resource cost of 20-40 mills per kilowatt-hour (real levelized 1989 dollars). . . . The net cost of the proposed Colorado-Ute transaction to our retail customers (67 MW) is approximately 25 mills/kwh (1992 dollars) on a 30-year real levelized basis. Thus, the acquisition of this resource is part of the implementation of [PacifiCorp's] integrated resource strategy that includes meeting customer needs with demand side, supply side and market place resources.[36]

Supporting document references related to the demand for Craig and Hayden power include:

- RAMPP-1 "Planning for Stable Growth" Excerpts (A.1)
- RAMPP-2 "Balanced Planning for Growth" Excerpts (A.2)
- Testimony and Exhibits of Dennis P. Steinberg in Support of Accounting Petition (B.6)
- Testimony and Exhibits of Gregory N. Duvall in Support of Accounting Petition (B.7)
- Load and Resource Analyses (B.10)
- RMI Study (B.13)
- Indexed documents in Attachment V under category entitled "Need for Power/Resource Planning" (B.14)

3.3.1.2 Impact on DSM Resources, System Optimality

As explained in the testimony of Dennis P. Steinberg in his prefiled testimony to the Commission in Docket No. UE-911186, the Colorado-Ute Acquisition did not reduce the

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[35] Reference Document B.7 at 9-10.

[36] Reference Document B.6 at 9-10.

importance of demand-side resource options identified in the RAMPP reports. Mr. Steinberg stated:

> With regard to other resource options, the Company is continuing to expand demand side programs, particularly pilot programs and capability building programs. The Company also issued its first competitive bid in October of this year. In that bid, the Company is seeking to purchase average megawatts from Qualifying Facilities, Independent Power Producers and Demand Side Management resource suppliers.[37]

Hayden Units 1 and 2 began commercial operation in 1965 and 1976, respectively, and Craig Units 1 and 2 commenced commercial operation in 1980 and 1979, respectively. The RMI Study concluded that Hayden Unit 1 has a lifetime availability of approximately 84.5%. The lifetime availability for Hayden Unit 2 was greater than 88.3%. The Craig Units 1 and 2 have a life-to-date availability of 90.2% and 89.3%, respectively.

PacifiCorp determined that the Craig and Hayden units would provide 30 years of service from the time of the purchase. As part of the Company's analysis, the Company concluded that life extension would be required for the Hayden Units in 1998 and 2009, respectively. As for the Craig Units, at the time of the acquisition, the Company determined that, due to the age of the units, an estimate of capital improvements for work to be performed in the 2012 to 2013 time frame would not be meaningful. PacifiCorp and the other owners of the Craig and Hayden units developed capital improvement programs to improve and upgrade the projects and to extend the units' lives.

In the past, the performance of the Hayden Units has operated between 68.6% (Hayden Unit 1, 1992) and 89% (Hayden Unit 2) capacity. The reduction in availability was due primarily to the failure of the main transformer in early 1992. Subsequent data from August 1992 showed an availability of the unit at greater than 96%. For the Craig Units, capacity ranged from 67.8% to 82.3% based on data from January 1991 through August 1992.

The Company's RAMPP projections also projected the energy generation of the Craig and Hayden units. In RAMPP-6, the projected annual average generation for the Craig Units was between 153 and 163 aMW. The projected annual average generation for the Hayden Units ranged between 69 and 72 aMW. These projections are greater than the projections in previous RAMPP reports for these units.

Supporting document references related to the Craig and Hayden units' impact on DSM and system optimality include:

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[37] Reference Document B.6 at 10-11.

- Testimony and Exhibits of Dennis P. Steinberg in Support of Accounting Petition (B.6)
- RAMPP-2 "Balanced Planning for Growth" Excerpts (A.2)
- RAMPP-3 "Positioning for Competition and Uncertainty" Excerpts (A.3)
- RAMPP-4 "Flexible Choices for a Changing Market" Excerpts (A.4)
- RAMPP-5 "PacifiCorp Resource and Market Planning Program" Excerpts (A.6)
- RAMPP-6 "Interim Report" Excerpts (A.7)
- RMI Study (B.13)

3.3.2 RFPs and the Resource Acquisition Process

During the time that PacifiCorp was negotiating and evaluating the acquisitions of the Craig and Hayden units, there was no formal requirement that PacifiCorp issue an RFP. The Company pursued the Colorado-Ute Acquisition because it represented a least-cost new resource option that conformed with the analyses and discussions presented in the Company's integrated resource plan.

Supporting document references regarding the RFP and acquisition process include:

- PacifiCorp's 1991 Request for Proposals (A.8)
- Testimony and Exhibits of Dennis P. Steinberg in Support of Accounting Petition (B.6)
- RAMPP-2 "Balanced Planning for Growth" Excerpts (A.2)
- RMI Study (B.13)
- Indexed documents in Attachment V under category entitled "Need for Power/Resource Planning" (B.14)

Alternatives available to PacifiCorp at the time the Craig and Hayden units became available included San Juan Unit 3 and San Juan Unit 4. Upon evaluating these and other alternatives that the Company considered at the time, the cost for the acquisition of the Craig and Hayden units compared favorably to other base load resource acquisition projects developed by other utilities.

Specifically, the City of Anaheim, California bought 50 MW of capacity from San Juan Unit 4 for approximately $1,140 per kW. Fuel and O&M costs for San Juan Unit 4 were approximately $25 per MWh. At the time PacifiCorp acquired the Craig and Hayden units, other publicly owned utilities in California completed a transaction to acquire 200 MW from San Juan Unit 3. That project cost approximately $930 per kW and fuel. O&M costs for the San Juan units totaled approximately $25 per MWh. In comparison, the estimated 1992 annual cost of energy from the Craig and Hayden units was approximately $31 to $32 per MWh. If PacifiCorp had acquired capacity from San Juan Unit 3 for $930 per kW, the total annual cost (assuming a 10.5% annual capacity factor and fuel and O&M costs of $25 per MWh) would be approximately $38 per MWh, which is 19% to 23% greater than the annual cost associated with the Craig and Hayden units.[38]

The annual costs of energy for the Craig and Hayden units also compared favorably to comparable alternatives discussed in the RAMPP reports. The 1992 annual cost of energy from the Craig and Hayden units ranged from approximately $31 per MWh to approximately $32 per MWh, depending on the assumed ultimate cost of the acquisitions. The costs for comparable alternatives discussed in the RAMPP-1 report ranged from approximately $37 to $73 per MWh. And in RAMPP-2, the costs for comparable alternatives ranged from approximately $35 per MWh to $66 per MWh.

With respect to alternatives available to PacifiCorp at the time of the Colorado-Ute Acquisition, the testimony of Gregory N. Duvall in Docket No. UE-911186 stated:

> [Reference Document B.9] . . . compares the real levelized life-cycle costs of the net Colorado-Ute resource to other resource options that have been identified in the Company's [RAMPP-1] and to the cost of Cholla Unit 4 which PacifiCorp has recently acquired. As can be seen from the table, the levelized cost of the net Colorado-Ute resource, which is 25 mills per kilowatt-hour, compares favorably with the other resource options the Company has available. The net Colorado-Ute resource is an excellent addition to the Company's resources.[39]

In a subsequent independent evaluation conducted by Resource Management International, Inc. (entitled "Evaluation of PacifiCorp's Acquisitions of Facilities from Arizona Public Service Company (APS) and Colorado-Ute Electric Association" or "RMI Study"), the consultants concluded that these resources were acquired on favorable terms. In the RMI Study, the Colorado-Ute Acquisition was determined to be "(i) less costly than all of the other resources, with the exception of the combined cycle unit, on a capacity cost basis; (ii) less costly than all of the RAMPP-2 resources, except for the mine-mouth coal-based resources and the 100 MW geothermal unit, on a variable cost (fuel plus O&M basis); and (iii) less costly than all of the RAMPP-2 resources on a total cost ($ per MWH) basis."[40] The RMI Study also compares the cost of the net capacity resource to PacifiCorp with the costs paid by PSCo under the joint plan and describes other acquisitions, at the time, of capacity from existing coal-fired units by other utilities within the WSCC area.[41]

Supporting document references related to the assessment and evaluation of alternatives include:

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[38] Reference Document B.13, RMI Study, vol II at 84-86.

[39] Reference Document B.7 at 7-8.

[40] Reference Document B.13, RMI Study, vol II at 84.

[41] *See id.* at 84–86.

- Testimony and Exhibits of Gregory N. Duvall in Support of Accounting Petition (B.7)
- Comparison of 1992 Real Levelized Life Cycle Costs (B.9)
- RAMPP-1 "Planning for Stable Growth" Excerpts (A.1)
- RAMPP-2 "Balanced Planning for Growth" Excerpts (A.2)
- RMI Study (B.13)
- Indexed documents in Attachment V under category entitled "Alternatives" (B.14)

3.3.3 Decision-Making Process

The total estimated cost of the Colorado-Ute Acquisition is approximately $279.1 million, or $1,149 per kW. The evaluations performed by PacifiCorp showed that the net present value of the net revenue requirement (compared to purchases at PacifiCorp's avoided cost) for PacifiCorp was approximately $68 million for the period 1992-2022 and approximately $83.6 million for the period 1993-2022. In other words, the net resource costs associated with the acquisitions under the joint plan are significantly less than would be the costs associated with acquiring the same amount of resources at PacifiCorp's avoided costs.

As part of its study, RMI performed its own analysis of PacifiCorp's evaluations. According to the RMI Study, these analyses revealed that because several factors were not yet solidified when the evaluations were done, (i) certain cost items, such as the price paid for the Craig and Hayden capacity, were understated in PacifiCorp's evaluation; (ii) certain items that should have been factored into the PacifiCorp evaluations were not; and (iii) certain costs were overstated in the PacifiCorp evaluation.[42] The results of RMI's sensitivity studies performed to test the effects of the above revealed that, in the composite, they would have no negative impact on the results of the PacifiCorp analysis and, in fact, would likely have net positive impacts. These composite studies resulted in net present value levels of approximately $70.2 million for the 1992-2022 period and of approximately $87.3 million for the 1993-2022 period.[43]

In support of its finding that PacifiCorp's actions were prudent from a cost perspective, the RMI Study compared the cost to PacifiCorp of capacity from the Craig and Hayden units of $1,070-1,149 per kW, with an associated fuel and O&M cost of approximately $15 per MWh. The City of Anaheim, California purchased capacity from San Juan Unit 4 at a cost of approximately $1,140 per kW; the fuel and O&M costs for the San Juan units is approximately $25 per MWh. Also, several publicly owned utilities in Southern California recently completed a transaction under which they acquired 200 MW from San Juan Unit 3 for a cost of approximately $930 per kW; the fuel and O&M costs for this unit are also approximately $25 per MWh.[44] If, for example, PacifiCorp had acquired capacity from the San Juan Unit 3 for $930 per kW, the annual cost would be approximately 22% to 26% more costly than the

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[42] Reference Document B.13, RMI Study, vol I at 22.

[43] *Id.*

[44] *Id.* at 20-21.

annual cost associated with the Craig and Hayden capacity (assuming a 10.5% cost of capital, a 78% annual capacity factor, and fuel and O&M costs of $25 per MWh for San Juan).

Reference Document B.4 presents the PacifiCorp spreadsheets evaluating the Colorado-Ute transaction, including the acquisition of the Craig and Hayden units. The testimony and exhibit of Gregory N. Duvall,[45] with respect to the cost-effectiveness of the Colorado-Ute Acquisition, states as follows:

> [T]he net Colorado-Ute resource has a 1992 real levelized cost of 25 mills per kilowatt hour, and a 1992 nominal levelized cost of 38 mills per kilowatt hour. . . . .
>
> This comparison [of net Colorado-Ute resource costs to the Company's avoided costs] indicates that the Colorado-Ute transaction will provide a net present value benefits of $68 million compared to avoided costs. The cost of the net Colorado-Ute resource is only 72% of the Company's avoided costs.[46]

With respect to the benefits of the Colorado-Ute Acquisition, Gregory N. Duvall's testimony concludes:

> [O]ver the next thirty years, the Colorado-Ute transactions will provide a present value net system benefit of $68 million when compared to the Company's avoided costs (adjusted to include a credit for sales for resale). This benefit increases to $84 million when 1992 is excluded due to the Company's price stability commitment.[47]

Supporting document references relating to decision criteria and analysis of project costs include:

- PacifiCorp's Petition to the Commission (B.5)
- Testimony and Exhibits of Dennis P. Steinberg in Support of Petition (B.6)
- Testimony and Exhibits of Gregory N. Duvall in Support of Petition (B.7)
- Testimony and Exhibits of Anne E. Eakin in Support of Petition (B.11)
- Commission Order Granting Petition as Amended (B.12)
- RMI Study (B.13)
- Indexed documents in Attachment V under category entitled "Other Regulatory Proceedings" (B.14)
- Asset Purchase and Power Exchange Agreement (B.1)

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[45] Reference Document B.7.

[46] Reference Document B.7 at 7..

[47] Reference Document B.7 at 2-3.

- PacifiCorp Analysis of Colorado-Ute Transaction (B.4)
- Value of Net Resource from Colorado-Ute Transactions (B.8)
- RAMPP-2 "Balanced Planning for Growth" Excerpts (A.2)
- Indexed documents in Attachment V under category entitled "Analysis of Project Costs" (B.14)

The Colorado-Ute Acquisition represents one of several major resource acquisitions the Company made since it began its integrated resource planning process. As part of its decision-making process, RAMPP-1 identified the availability of energy and capacity from existing generating resources of the Rocky Mountain and desert Southwest utilities. Purchases and Contract Rights made up a significant fraction of the RAMPP-1 New Resource Portfolio. The net cost of the Colorado-Ute Acquisition was estimated at approximately 25 mills per kWh (1992 dollars) on a 30-year real levelized basis. Therefore, PacifiCorp concluded that the Colorado-Ute Acquisition is part of the implementation of the Company's integrated resource planning process.

On February 20, 1991 the proposed asset acquisition and power supply arrangement for the Colorado-Ute transaction was presented to the PacifiCorp Board of Directors.[48] The presentation included:

- Description of Colorado-Ute transactions as compared with APS transactions (p. 1)
- Map showing location of Colorado-Ute facilities and selected transmission lines (p. 2)
- Description of Colorado-Ute bankruptcy proceedings (p. 3)
- Summary of proposed asset acquisition and power supply arrangements in the Colorado-Ute transaction (p. 4)
- Economic analysis of transaction, showing net resources purchased by PacifiCorp (100 MW, 86-MW average) and net benefits to customers of $83 million, or $3/MWh) (p. 5)
- Description of environmental aspects of transactions (p. 6)
- Description of conditions and contingencies under the transactions (pp. 7-8)
- Discussion of strategic implications of transaction (p. 9)
- Identification of next steps to consummate the transactions (p. 10)

Other supporting document references include:

- February 20, 1991 Presentation to PacifiCorp Board of Directors (B.3)
- RAMPP-1 "Planning for Stable Growth" Excerpts (A.1)
- RAMPP-2 "Balanced Planning for Growth" Excerpts (A.2)
- RMI Study (B.13)
- Indexed documents in Attachment V under category entitled "Need for Power/Resource Planning" (B.14)

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[48] Reference Document B.3.

- Indexed documents in Attachment V under category entitled "Analysis of Project Costs" (B.14)
- Indexed documents in Attachment V under category entitled "Other Regulatory Proceedings" (B.14)

3.3.4 Staff's Assessment of Prudency of Craig and Hayden Plants

Staff assessed that the load growth or demand projections resulting from the resource optimization algorithm presented in RAMPP-1 indicated that, assuming a medium-case scenario of growth in demand, remaining life of existing resources, and other constraints, the Company requires about 1,400 MW of generation resources by 2008.

The medium-case forecast in RAMPP-1 projected a need for 115 aMW of Purchases and Contract Rights by 1995. The same report also indicated that the demand for generation resource would increase to 215 aMW by 2005 and to 353 aMW by 2008.

PacifiCorp acquired 243 MW of existing coal-fired thermal resources from Craig Units 1 and 2 and Hayden Units 1 and 2. Of the total 243 MW, 176 MW was resold, leaving 67MW. At a capacity factor of 78%, the acquisitions of Craig and Hayden will provide approximately 52 aMW of net resource to PacifiCorp. With the net resources from Cholla Unit No. 4 of approximately 105 aMW, the acquisition of Craig and Hayden represent a total capacity increase of 157 aMW.

During the time PacifiCorp was planning to acquire new resources, there was no formal requirement that PacifiCorp issue an RFP. Nonetheless, the Company compared Purchases and Contract Rights with alternatives such as San Juan Unit 3 and San Juan Unit 4. The annual cost of acquiring San Juan ranged from $40-$60/MWh (levelized) while that of Craig 1 and 2 was $27-$60, resulting in approximately 22% to 26% less annual cost associated with the Craig and Hayden capacity. The net cost of Craig and Hayden was estimated at approximately 25 mills per kWh (on a 30-year real levelized basis). The Company pursued the Colorado-Ute Acquisition because it represented a new resource option that is least-cost compared to alternatives considered.

The Craig and Hayden units provided the needed load within the bounds of the estimated load demand contained in the Company's resource plan. In Staff's view, at the time the resource was acquired, the Company did not lack resources. However, the Company acquired these resource not only because they were cheap, but also because the Company was opportunistic in the sense that it is very unlikely to find projects of this nature that would prove to be useful to customers. That is why the Company sold nearly 70% of purchased capacity. The fact that there was no RFP requirement indicates that Staff is unable to determine the fairness of the acquisition process. Nonetheless, Staff believes that the Craig and Hayden units were acquired prudently in the sense that they were intended to satisfy the system-load requirement, were low-cost, and provide an added benefit through sale at a higher price.

3.4 ACQUISITION OF JAMES RIVER COGENERATION PROJECT

The James River Camas Cogeneration project (the "James River Cogeneration Project") is a 50-MW high-pressure steam-fired cogeneration facility at the James River Corporation ("James River") pulp and paper mill located in Camas, Washington. The James River Camas mill is across the Columbia River from, and electrically linked by three separate transmission lines to, PacifiCorp's Troutdale substation. PacifiCorp provides electric power and energy to James River, which creates high-pressure steam that is harnessed to generate the 50 MW of power.

On January 13, 1993, PacifiCorp and James River entered into a 20-year agreement for the development and operation of the James River Cogeneration Project. PacifiCorp owns the facility and, upon commencement of construction of the project and the related removal from service of the existing turbine generators, the Camas mill is served under the same price as contained in PaciCorp's Tariff Schedule 48T. PacifiCorp also owns the transmission facilities and recovers the revenue requirements on full capital investment and major maintenance.

The steam turbine generation unit has an estimated heat rate of 4,381 Btu/kWh, which is two times more efficient than a conventional utility thermal plant. Steam for the turbine generator is provided by existing boilers. Fuel types include natural gas, black liquor,[49] and hog fuel.[50]

The project also included necessary mill modernization upgrades. For example, it was necessary to upgrade the super-heaters in two large chemical recovery boilers to produce steam at an adequate temperature. Steam used to run paper machines was rerouted to the James River Cogeneration Project. The rerouting process entailed replacing three mechanical drive turbines with electrical drives to optimize the efficiency of the mill to allow all the high-pressure steam from the boilers to be used by the new steam turbine. Piping was upgraded, and a short natural gas pipeline was installed to connect the mill to Northwest Pipeline.

PacifiCorp financed the James River Cogeneration Project, and James River acted as construction manager and was responsible for total implementation including engineering, construction, and start-up. The budgeted capital cost for the project amounted to $59 million, which included costs of improvements and the turbine generator and related facilities. The project was scheduled to begin on or about January 11, 1993 and to be completed in late 1995.

Supporting document references regarding the acquisition of the James River Cogeneration Project include:

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[49] Black liquor is a mixture of organic and inorganic substances derived from the pulping process. It is recycled to a recovery boiler that performs the duel function of recovering chemicals and energy.

[50] Hog fuel is a shredded coarse chip of unpainted woody debris from construction and land-clearing operations.

- October 8, 1992 Letter Agreement (D.1)
- Camas Development, Construction, Operation and Steam Supply Agreement between PacifiCorp and James River Paper Company, Inc. dated as of January 13, 1993 (D.2)
- June 15, 1992 Presentation to PacifiCorp Management Council (D.7)
- July 22, 1992 Board Presentation regarding James River Camas Cogeneration Project (D.8)
- Gregory N. Duvall Testimony and Exhibits (D.10)
- Indexed documents in Attachment U under category entitled "Need for Power/Resource Planning" (D.12)
- Indexed documents in Attachment U under category entitled "Contract Negotiations" (D.12)
- Indexed documents in Attachment U under category entitled "Pre-Operation General Correspondence" (D.12)
- Indexed documents in Attachment U under category entitled "Analysis of Project Costs" (D.12)

3.4.1 Demand for James River Cogeneration Project

3.4.1.1 Results from RAMPP

The RAMPP action plans reflected a need for the Company to maintain a margin of resources above load to ensure reliable service in the event of load fluctuations, unit outages, or other unforeseen events. The RAMPP action plans specifically refer to cogeneration as a potential marketplace option.

In 1989, RAMPP-1 identified cogeneration as a potential source of new generation and identified the need to develop and test contractual arrangements with the most economical cogeneration candidates. Cogeneration at customer locations is an attractive option to meet load requirements because of the inherent total energy efficiency opportunities found at certain large industrial locations. The RAMPP-1 action plan called for the company to include up to 180 aMW of cogeneration by 1995 and up to 290 aMW of cogeneration by 2000.

In June 1992, RAMPP-2 provided that cogeneration is an essential component of strategies to meet load growth. The models included cogeneration in all plans except low load forecast. In all other cases the models added 160 aMW to 849 aMW of cogeneration by 2001. The action plan reflected a need for the Company to sign intent agreements and pursue contract negotiations with industrial customers to have up to 300 aMW of cogeneration on-line by 1997.

In April 1994, PacifiCorp completed RAMPP-3. With RAMPP-3, the Company determined that it should continue to acquire cogeneration projects. The models added significant amounts of cogeneration under conditions the Company regarded as likely, including medium load growth, medium demand-side resource amounts, and the addition of strategic renewable resources. The amount of cogeneration additions by 2001 ranged from 276 to 481 MW. At that time, the James River Cogeneration Project was under construction and was a low-cost fuel resource that contributed to a diverse resource mix compared with alternatives evaluated at that time. The expected potential energy for the project was 51 aMW.

Supporting document references regarding RAMPP results include:

- RAMPP-1 "Planning for Stable Growth" Excerpts (A.1)
- RAMPP-2 "Balanced Planning for Growth" Excerpts (A.1)
- RAMPP-3 "Positioning for Competition and Uncertainty" Excerpts (A.3)
- Indexed documents in Attachment U under category entitled "Need for Resource/Resource Planning" (A.12)
- Indexed documents in Attachment U under category entitled "Contract Negotiations" (A.12)

3.4.1.2 Impact on DSM Resources, System Optimality

PacifiCorp's integrated resource planning process includes an analysis of DSM resources in addition to supply-side resources. DSM resources include implementing conservation measures and increasing the energy efficiency of new and existing buildings. The level of demand-side resources varies with the load forecast, because estimates of potential savings depend on the forecast used, as well as on detailed end-use information. The amount of electricity that can be saved through energy efficiency measures is directly tied to the number of homes, businesses, and industries served.

For December 1995, the James River Cogeneration Project's average capacity utilization was 65% and averaged 20.8 MW. For 1996, a MW ranged from 30.7 MW in January to 45.4 MW in December, with the exception of March 1996, when the project's uptime was 14.6% and generated an average of 6.4 MW. PacifiCorp sent engineers and support people to the facility to provide training, evaluation, and efficiency improvements to address the efficiency issues.[51]

By February 1997, the James River Cogeneration Project achieved a 100% uptime and an average capability utilization of 95.3% to generate an average of 44.9 MW. In December 1997, the project generated an average of 46.9 MW.[52] Lost generation was generally attributable to load-related conditions, including scheduled boiler maintenance outages and boiler trips.

Supporting document references regarding the impact on DSM resources and system optimality include:

- RAMPP-2 "Balanced Planning for Growth" Excerpts (A.2)
- RAMPP-3 "Positioning for Competition and Uncertainty" Excerpts (A.3)
- RAMPP-4 "Flexible Choices for a Changing Market" Excerpts (A.4)

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[51] 1997 IRP Report at 21-23; Reference Document D.12, Attachment U.

[52] Reference Document D.12, Attachment U.

- RAMPP-5 "PacifiCorp Resource and Market Planning Program" Excerpts (A.6)
- 1997 IRP Report "PacifiCorp RAMPP-4 Update" Excerpts (A.7)
- Indexed documents in Attachment U under category entitled "Project Optimality/Performance" (D.12)

3.4.2 RFPs and the Resource Acquisition Process

During the time that PacifiCorp was negotiating and evaluating the James River Cogeneration Project, there was no formal requirement that PacifiCorp issue an RFP. James River solicited the Company, and negotiations were underway to complete the development agreement before PacifiCorp's RFP process began. The Company pursued the James River Cogeneration Project because it represented an unsolicited potential new resource option with low-cost potential as reported in the Company's least-cost plan. According to the presentation to PacifiCorp's Board of Directors, the cost of the output from the James River Cogeneration Project was projected to be 93% of 1991 avoided costs and 86% of 1992 avoided costs, which "[c]ompares favorably to the best resources identified through our Request for Proposal."[53]

Supporting document references regarding the RFP and acquisition process for the James River Cogeneration Project include:

- July 22, 1992 Presentation to PacifiCorp Board of Directors (D.8)
- PacifiCorp's 1991 Request for Proposals (A.8)
- RMI Study of the Acquisition of the Hermiston Co-Generation Facility by PacifiCorp Excerpts (F.10)
- RAMPP-2 "Balanced Planning for Growth" Excerpts (A.2)
- RAMPP-3 "Positioning for Competition and Uncertainty" Excerpts (A.3)

James River initially solicited PacifiCorp as part of James River's RFP process for PacifiCorp to consider participating in the evaluation of three potential cogeneration projects at three James River mill sites: Camas, Wauna, and Halsey.

The Company determined that Camas and Wauna were two viable cogeneration options, but considered Wauna as a resource opportunity, not an ownership option.

The Wauna paper mill's estimated capacity was approximately 22 MW compared to the then estimated 44 MW capacity of Camas.[54] Although Wauna was originally thought to be the more economic (less than $10/MWh, excluding incremental gas) and a simpler installation,[55] it was later determined that significant incremental gas would be required to maintain process flows. Estimates for this incremental gas were about $12 per MWh, which, when combined

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[53] Reference Document D.8 at 8.

[54] Reference Document D.11 contains documents relating to the Wauna mill alternative.

[55] Reference Document D.11 at 1.

with the capital costs of $9/MWh, made the James River Cogeneration Project (Camas) the preferred project to pursue.

The James River Cogeneration Project also compared favorably to the Company's avoided costs. As explained in the testimony and exhibits of Rodger Weaver,[56] the James River Cogeneration Project power cost savings was estimated at almost $17 million as compared to PacifiCorp's avoided costs.[57] Table 4-2 attached to Rodger Weaver's testimony compares the costs of the James River Cogeneration Project to the Company's avoided cost stream based on RAMPP-1.

In the Company's view, the James River Cogeneration Project is an efficient and low-cost resource that helps meet customers' needs for power. As indicated by the testimony of Rodger Weaver:

> The most obvious benefit is the acquisition of a new low-cost generation resource. This resource fits well with the Company's current resource acquisition planning in terms of timing, size, and type of resource. Its low cost when compared to the avoided cost filings derived from [RAMPP-1 and RAMPP-2] is a clear indicator of the benefit of this project. The risk reduction aspects of the business arrangements between the Company and James River discussed by Mr. Duvall augment the low-cost resource advantages. Another significant benefit is derived from the location of the project at the Company's major load center on the west side of the Cascade Mountains. Also, the agreement implementing the project gives PacifiCorp a "right of first refusal" to participate in James River's future combustion turbine generation project . . . . Since such resources constitute a significant portion of the Company's future resource acquisition planning, this option on the west side is likely to be particularly attractive.[58]

The James River Cogeneration Project also benefits customers because it is ideally situated to serve Washington customers. Again, Rodger Weaver's testimony explains this benefit:

> Installation of the 50 MW facility at James River's Camas site will provide benefits to all power users in the Willamette Valley and southwest Washington areas. These benefits are due to reduced exposure to possible transmission system voltage

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[56] Reference Document D.9.

[57] Reference Document D.9 at 4.

[58] Reference Document D.9 at 1-2.

collapse. This event could be triggered by loss of critical 500 kV lines which cross the Cascades. Like all transmission facilities, these lines are vulnerable to storms and other risk factors. While no immediate danger exists, voltage collapse of the sort described is projected to become a risk by the winter of 2002. The James River Camas cogeneration facility will reduce the region's exposure to load loss by one MW for each MW of plant size. Utilities in the affected area are planning other improvements to reduce this exposure. Reliable generation operating in the area will help defer such expenditures.[59]

PacifiCorp also negotiated the purchase price for the steam provided by James River to be computed using a steam royalty formula. The prices are about 95% of avoided costs over the 20-year contract period. In this manner, PacifiCorp can recoup the costs of the project through the royalty payment schedule.

The steps taken by the Company to mitigate risks associated with the James River Cogeneration Project also benefit PacifiCorp's retail customers.[60] The testimony and exhibits of Gregory N. Duvall describe this benefit:

> Several steps have been taken [to mitigate the risks for retail customers]. First, James River is taking the construction risk. For amounts below $64 million, the steam royalty payment reflects the actual costs of construction. In other words, the higher the construction costs, the lower the steam royalty payment.[61] In addition, James River will directly pay amounts over $64 million.
>
> Second, James River is taking the fuel risk. PacifiCorp customers are protected from increases in the cost of fuel.
> Third, as illustrated in Table 2-3, steam royalty payments are not made until all of the Company's annual costs are met. This provision includes any costs carried over from prior years. The contract specifies that James River is paid last.
>
> Finally, the Company is accorded rights to operate the generation in the event that the Camas Mill is shut down. These rights allow the Company to operate the mill's boilers and related equipment

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[59] Reference Document D.9 at 5.

[60] Reference Document D.10.

[61] The steam royalty is determined by dividing the residual cost to PacifiCorp after payment of development and capital cost. Therefore, if development and capital cost is higher, there will be less residual cost to satisfy the revenue requirement and royalty payment.

to provide steam for the steam turbine generators, access fuel supply and fuel transportation facilities, and add facilities to operate the steam turbine generator as a condensing unit.[62]

A June 15, 1992 presentation to PacifiCorp Management Council identified the following benefits associated with the James River Cogeneration Project:

- Cost-effective resource at 95% of 1991 avoided costs
- Retention of long-term customer retail load
- Rate base capital investment provides the opportunity for earnings growth
- Manageable fuel risk
- Partnership with a major customer
- Exercising RAMPP portfolio, further diversifying resource base
- High efficiency cogeneration—excellent heat rate—comparable to "green" power
- Uses proven technology
- No additional environmental permitting required
- James River is experienced power plant operator[63]

Supporting document references regarding the assessment and evaluation of alternatives to the James River Cogeneration Project include:

- Rodger Weaver Testimony and Exhibits (D.9)
- Gregory N. Duvall Testimony and Exhibits (D.10)
- June 15, 1992 Presentation to PacifiCorp Management Council (D.7)
- Camas Development, Construction, Operation and Steam Supply Agreement between PacifiCorp and James River Paper Company, Inc. dated as of January 13, 1993 (D.2)
- RAMPP-2 "Balanced Planning for Growth" Excerpts (A.2)
- RAMPP-3 "Positioning for Competition and Uncertainty" Excerpts (A.3)
- Documents related to evaluation of Wauna alternative (D.11)
- Indexed documents in Attachment U under category entitled "Board Presentations" (D.12)
- Indexed documents in Attachment U under category entitled "Alternatives" (D.12)

3.4.3 Decision-Making Process

PacifiCorp's RAMPP identified cogeneration as one of the variety of resources to provide economic new sources of power. The acquisition of the James River Cogeneration Project represents a low-cost resource as discussed in RAMPP 2. It adds new load through partnering with an existing customer, is environmentally sound and efficient, and returns the retail customer to standard industrial tariff pricing. In 1992, the James River Cogeneration

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62 Reference Document D.10 at 7-8.

63 Reference Document D.7 at 11.

Project's estimated power costs were calculated at 86% of PacifiCorp's then current avoided costs.

The James River Cogeneration Project is a low-cost resource compared to avoided-cost filings derived from RAMPP-1 and RAMPP-2. On average, the costs of the project are less than the Company's avoided costs, with increased benefits over time. A comparison of the estimated cost of output from the James River Cogeneration Project with then current estimates of avoided costs and with the avoided costs as then approved by the Oregon Public Utility Commission is presented in Table 4-2 attached to the testimony of Rodger Weaver. As noted by Rodger Weaver:

> [F]or the first five years, power from the project is more expensive than if purchased at avoided cost. From the sixth through the 20th years, the project is less expensive than capacity and energy priced at avoided cost. The present value of the savings from the project over the 20 years of the project is almost $11 million. This represents a 5% savings relative to energy purchased at avoided costs. In other words, the levelized cost per MWh of the James River Cogeneration project is 95% of a corresponding capacity and energy purchase at the Company's avoided costs.[64]

The total capital costs of the James River Cogeneration Project were estimated to be $59,162,000 during construction for the steam turbine generator. That sum represented costs of development, construction, and construction oversight and PacifiCorp's financing costs. James River was responsible for directly paying all capital costs exceeding $64 million.

Supporting document references regarding decision criteria and analysis of project costs include:

- James River Camas Cogeneration Project July 22, 1992 Presentation to Pacific Power Board (D.8)
- Rodger Weaver Testimony and Exhibits (D.9)
- Camas Development, Construction, Operation and Steam Supply Agreement between PacifiCorp and James River Paper Company, Inc. dated January 13, 1993 (D.2)
- Indexed documents in Attachment U under category entitled "Analysis of Project Costs" (D.12)
- Indexed documents in Attachment U under category entitled "Contract Negotiations" (D.12)
- Indexed documents in Attachment U under category entitled "Board Presentations" (D.12)

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[64] Reference Document D.9 at 3.

The Company evaluated and prioritized potential cogeneration projects as to timing and detail. James River, one of PacifiCorp's industrial customers, solicited the Company for a proposal to develop the James River Cogeneration Project. PacifiCorp conducted an analysis of the project and compared the costs of the potential output to the Company's avoided costs. The results of that analysis reflected that the James River Cogeneration Project would be a cost-competitive resource compared with similar projects available to the Company at that time.

The James River Cogeneration Project represents a partnership with one of the Company's largest customers in the Pacific Division. PacifiCorp determined that it was a solid project and would be built with or without its involvement. The negligible fuel risk and existing relationship with James River added to the decision to move forward with the project. Also, the steam turbine generator uses proven technology to create high-efficiency cogeneration with an excellent heat rate comparable to "green" power. And no additional environmental permitting was required. The Company considered all of these factors in addition to cost in its decision making.

On June 15, 1992 a presentation was made to PacifiCorp's Management Council regarding the James River Cogeneration Project.[65] The presentation included:

- Description of features of the transaction (p. 1)
- Description of location of the project in reference to PacifiCorp's substation (p. 2)
- Background information regarding James River (p. 3)
- History of pulp and paper tariff customers (pp. 4–5)
- Description of the project (p. 6)
- Schematic depicting the engineering of the project (p. 7)
- Summary of the assumptions regarding the project (p. 8)
- Description of the financial arrangement of the project, including royalty payments and project capital expenditures (p. 9)
- Description of projected earnings (p. 10)
- Identification of benefits and risks related to the transaction (pp. 11–12)

On July 22, 1992 a similar presentation was made to the Pacific Power Board regarding the James River Cogeneration Project.[66]

As part of the negotiation process, an engineering feasibility study of the cogeneration potential at the James River Camas mill was conducted by Harris Group Inc. PacifiCorp agreed to fund that study. Harris Group Inc. determined that installation of a new turbine generator could generate up to 46 MW.

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[65] Reference Document D.7.

[66] The presentation is included at Reference Document D.8.

PacifiCorp negotiated the project to mitigate risk and maintain a level of control over the project. The Company owns the turbine generator and transmission facilities and the ancillary switch gear and transformer. The Company also recovers revenue requirements on full capital investment and major maintenance costs. Risk is mitigated because James River is responsible to deliver high-pressure steam to the turbine and to provide for all fuel and associated risks involved in the delivery of the steam. James River also is responsible for capital cost risks and taxes. James River agreed to guarantee steam for a 95 percent capacity factor, pay all taxes, and become a full requirements retail customer.

Supporting document references regarding the decision-making process for the James River Cogeneration Project include:

- June 15, 1992 Presentation to PacifiCorp Management Council (D.7)
- July 22, 1992 Presentation to Pacific Power Board (D.8)
- RAMPP-1 "Planning for Stable Growth" Excerpts (A.1)
- RAMPP-2 "Balanced Planning for Growth" Excerpts (A.2)
- Indexed documents in Attachment U under category entitled "Need for Power/Resource Planning" (D.12)
- Indexed documents in Attachment U under category entitled "Analysis of Project Costs" (D.12)
- Indexed documents in Attachment U under category entitled "Board Presentations" (D.12)

3.4.4 Staff's Assessment of Prudency of the James River Cogeneration Project

The long-term integrated resource plan shows whether or not an investor-owned utility needs new resources to meet demand, how much it needs, and when it needs it, including the quality and type of resource needed. PacifiCorp's 1989 RAMPP report not only projected needs of additional load but also identified cogeneration as a potential source of new power. The results of technical analysis in RAMPP-1 indicated up to 180 aMW of cogeneration was needed by 1995 and up to 290 aMW of cogeneration was needed by 2000.

At the time PacifiCorp was planning to acquire cogeneration projects, there was no formal requirement that PacifiCorp issue an RFP. Thus Staff cannot determine the conduct of an RFP process pursuant to WAC 480-107-060.

The cost associated with James River was projected to be 90% of 1991 and 1992 avoided costs. Furthermore, the cost of operating James River was less than those reported by projects submitted in the 1991-92 RFPs. Moreover, the Company attempted to minimize risks associated with James River by enabling the seller to guarantee steam for a 95% capacity factor, pay all taxes, and become a full-requirements retail customer. The James River Cogeneration Project, therefore, represented a low-cost resource with an added benefit of expanding the diversity of resource mix.

The project was acquired based on system-wide need as demonstrated in the Company's least-cost plans. The cost incurred is minimal compared to valuation of power at the

Company's avoided cost. The risk that the project could pose is mitigated through sharing with the seller. Thus the project is acquired prudently to satisfy system needs and resource mix.

3.5 ACQUISITION OF HERMISTON COGENERATION PROJECT

The Hermiston project is a 470-MW natural gas-fired cogeneration facility located near Hermiston, Oregon. PacifiCorp and U.S. Generating Company, L.P. ("U.S. Generating") each own 50% of the facility and, under a 20-year Power Sales Agreement ("PSA"), PacifiCorp accepts all of the generated power from the 50% of the project that it does not own. Construction began in November 1994 and the facility began operation in July 1996. The fuel supply for the Hermiston project is provided under a long-term, fixed-price contract (with predetermined escalation).

Supporting document references related to the acquisition of the Hermiston cogeneration project include:

- Long-Term Power Sales Agreement between Hermiston Generating Company, L.P. and PacifiCorp dated October 7, 1993 (F.1)
- Option Agreement between Hermiston Generating Company, L.P. and PacifiCorp dated October 7, 1993 (F.2)
- Security Agreement between Hermiston Generating Company, L.P. and PacifiCorp dated October 7, 1993 (F.3)
- Letter of Credit Agreement between Hermiston Generating Company, L.P. and PacifiCorp dated October 7, 1993 (F.4)
- Hermiston Project Memorandum of Understanding between Hermiston Generating Company, L.P. and PacifiCorp dated August 11, 1993 (F.5)
- Hermiston Project Purchase Agreement between Hermiston Generating Company, L.P. and PacifiCorp dated December 30, 1994 (F.6)
- Indexed documents in Attachment N under category entitled "Contract Negotiation" (F.12)

3.5.1 Demand for Hermiston

3.5.1.1 Results from RAMPP

RAMPP-2 was completed in May 1992 and provided the basis for the Company's decision to acquire output from the Hermiston facility.[67] RAMPP-2 forecasted a need for additional generation by the 1996 winter season (shortages were forecast before 1996, but it was believed that short-term purchases could suffice in the interim). In response to these resource needs, RAMPP-2 recommended that the Company pursue both near- and long-term acquisition action plans. As a further refinement, RAMPP-3 showed that without Hermiston the Company would need 326 MW of new resources by the 1996-97 winter season.

[67] In April 1994, RAMPP-3 superseded RAMPP-2.

This information was continually provided to the Company's Board of Directors and, in reliance on RAMPP-2's forecasts and recommendations, the Company began to investigate and evaluate a variety of resource options.

Supporting document references related to RAMPP results include:

- RAMPP-2 Integrated Resource Plan, "Balancing Planning for Growth," June 1992 (A.2)
- RAMPP-3 Integrated Resource Plan, "Positioning for Competition and Uncertainty," April 1994 (A.3)
- Pages 4-1 through 4-3 of the RMI Study[68] (Reference Document F.10), which discuss the demonstrated need for the resource
- April 1993 presentation to the PacifiCorp Board of Directors regarding resource planning, power supply issues (F.7)
- August 18, 1993 presentation to the PacifiCorp Board of Directors (Reference Document F.8), which shows PacifiCorp's Load and Resource Balance for Winter Peaks 1990, 1993, and 1996, respectively, and includes the identification of a 326-MW deficiency in 1996. Pages 2-3 of that board presentation show the forecasted requirements and existing resources for the period 1992 through 2003 for winter and summer peaks, respectively, and demonstrate an anticipated resource deficiency.
- Indexed documents in Attachment N under category entitled "Need for Power/Resource Planning" (F.12)

3.5.1.2 Impact on DSM Resources, System Optimality

PacifiCorp's RAMPP process includes an analysis of DSM resources in addition to supply-side resources. DSM resources include implementing conservation measures and increasing the energy efficiency of new and existing buildings. The level of demand-side resources varies with the load forecast, because estimates of potential savings depend on the

[68] Reference Document F.10 is a report prepared by Resource Management International, Inc. entitled "Study of the Acquisition of the Hermiston Co-Generation Facility by PacifiCorp." This study was prepared in May 1997 for the Utah Department of Commerce, Division of Public Utilities. According to the study, the purpose was to "provide state regulatory bodies with objective evidence and analysis as to whether the Transaction was in the best interests of PacifiCorp's customers consistent with achieving overall minimum costs while maintaining long term, reliable service." Key factors included (i) a comparison of the life-cycle costs of the resource with other resource options available to PacifiCorp at the time the Hermiston decisions were made, (ii) a comparison of the action plans recommended in PacifiCorp's least-cost plans with the various aspects of the transaction, and (iii) the documentation of other risks and costs associated with the transaction. (RMI Hermiston Study at ES-1)

forecast used and on detailed end-use information. The amount of electricity that can be saved through energy efficiency measures is directly tied to the number of homes, businesses, and industries served.

Demand-side resources are not directly affected by the acquisition or development of a particular resource. At the same time, lower costs of supply-side resources affect the level of DSM. For example, RAMPP-4 added less DSM than RAMPP-3 at the medium DSM level due to two primary changes: lower system needs and lower costs of new supply-side resources that were competitive with DSM. The lower costs of new supply-side resources reduced the level of cost-effective DSM from 23 aMW in RAMPP-4 to 15.7 aMW in RAMPP-5.

As part of the initial agreement to acquire power from Hermiston, PacifiCorp obtained an option to acquire 50 percent ownership of the facility. This option could be exercised (i) at commercial operation, (ii) after 5 years, or (iii) after 20 years.

In July 1994, PacifiCorp initiated a formal evaluation of the economics of exercising its option. This analysis showed that levelized cost of ownership over the 20-year period was $43.76/MWh as compared to a levelized cost of $45.92/MWh for continued purchase of the entire output. Based on this information, the Board of Directors decided to exercise the purchase option, effective upon completion. Delaying partial ownership until commercial operation, such as the Company did here, may result in benefits associated with ownership without the risk of siting, construction, and initial financing.

In 1997, RMI determined that the price paid for PacifiCorp's 50% interest was reasonable and that PacifiCorp's customers should receive financial benefits compared to purchasing only the output.

As a related issue, Resource Management International, Inc. also inquired as to why PacifiCorp contracted with U.S. Generating, rather than constructing PacifiCorp's own facility. This alternative had been rejected by PacifiCorp because (i) U.S. Generating was an experienced developer and operator, (ii) the Hermiston facility already had a site and cogeneration host, (iii) Hermiston was the cheapest option available at that time, and (iv) PacifiCorp did not have any experience in building such a facility. Furthermore, by purchasing one-half of a larger project, PacifiCorp benefited from economies of scale for certain infrastructure, equipment, and materials.

Supporting document references related to impact on DSM resources and system optimality for the Hermiston cogeneration project include:

- RAMPP-2 "Balanced Planning for Growth" Excerpts (A.2)
- RAMPP-3 "Positioning for Competition and Uncertainty" Excerpts (A.3)
- RAMPP-4 "Flexible Choices for a Changing Market" Excerpts (A.4)
- RAMPP-5 "PacifiCorp Resource and Market Planning Program" Excerpts (A.6)
- RAMPP-6 "Interim Report" Excerpts (A.7)

- March 1995 presentation to the PacifiCorp Board of Directors regarding exercise of option to purchase 50% of Hermiston project (F.11)
- Indexed documents in Reference Document N under category entitled "Exercise of Purchase Option" (F.12)
- PacifiCorp's formal evaluation of the economics of exercising its option to acquire a 50% undivided interest in the project is described at pages 3-9 and 3-10 of the RMI Hermiston Study (Reference Document F.10) and shows that the levelized cost of ownership over the 20-year period was $43.76/MWh as compared to a levelized cost of $45.92/MWh for continued purchase.
- Resource Management International, Inc. concluded that "[t]he price paid by PacifiCorp for a 50 percent undivided interest in Hermiston appears favorable based on the costs of similar resources. In addition, PacifiCorp's customers should receive financial benefits because of the decision to acquire a share of the Project compared to purchasing an equivalent amount of capacity from HGC." (Reference Document F.10 at ES-2)

3.5.2 RFPs and the Resource Acquisition Process

Acting on the RAMPP-2 recommendation, PacifiCorp issued an RFP in 1991 and 1992 and reviewed and considered approximately 20 resource acquisition opportunities in 1992 and 1993. Projects considered by the Company are listed in Table 3.

TABLE 3. List of Projects Considered as a Result of PacifiCorp's 1991 RFP

Name	Location/State
Enserch	Kalama, WA
Tenaska	Malin & Brooks, OR
Coburg Power	Coburg, OR
Westmoreland	Utah
Destec	Kalama, WA
KVA	Goldendale, WA
Air Products	Newberg, OR
Zurn Industries	Ferndale, WA
Exxon	Shute Creek, WY
Sithe Energy	Albany, OR
Unocal	Kennewick, WA
LG&E	Centralia, WA
Westinghouse	Satsop, WA
Makowski	Thurston County, WA
Cowlitz/Mission Energy	Longview, WA
Hermiston	Hermiston, OR

During this evaluation, many of the projects were eliminated for economic or other reasons. A November 1992 report entitled "Evaluation Process and Results of Supply Side Resources" discusses PacifiCorp's analyses of the competitive bid proposals and the bases for not selecting particular projects. The Zurn Industries project, for its part, offered a price that was sufficiently attractive to interest the Company in pursuing additional discussions. Before the completion of the RFP process, however, Zurn Industries informed the Company that it was withdrawing its proposal.

Supporting document references regarding the RFP and acquisition process include:

- PacifiCorp's 1991 Request for Proposals, Evaluation Report (A.8)
- RAMPP-2 "Balanced Planning for Growth" Excerpts (A.2)
- RAMPP-3 "Positioning for Competition and Uncertainty" Excerpts (A.3)

PacifiCorp considered numerous alternatives before proceeding with the Hermiston cogeneration facility. As noted above, PacifiCorp issued an RFP and reviewed and considered approximately 20 resource acquisition opportunities in 1992 and 1993. According to the Company, many of the projects were eliminated for economic or other reasons. A November 1992 report entitled "Evaluation Process and Results of Supply Side Resources" discusses PacifiCorp's analyses of the competitive bid proposals and the bases for not selecting particular projects.

In March 1993, the Company had the opportunity to purchase 406 MW of output from a cogeneration facility in Longview, Washington (the "Cowlitz project"). The Company pursued this opportunity and in April 1993 entered into a Memorandum of Understanding (the "MOU").

Pursuant to the MOU, PacifiCorp surveyed the market to determine whether the Cowlitz project was the least-cost option. This comparison revealed that the Hermiston project was the least-cost alternative, with the Cowlitz project being a close second. Based on this information and on the continued resource need, the Company decided to pursue both projects. As negotiations proceeded with both Hermiston and Cowlitz, each project offered additional reductions in power prices.

During this negotiation period, the Board of Directors was provided price comparisons between Hermiston, Cowlitz, the Company's filed avoided costs, a combined-cycle combustion turbine project, and projected wholesale prices. The costs for both Hermiston and Cowlitz compared very favorably with the costs of other options (costs for the Hermiston facility were 73% of PacifiCorp's then current avoided costs). Based on this information, other alternatives were eliminated, and the Company proceeded with the Hermiston and Cowlitz projects.

Because the Board of Directors determined that Hermiston was the least-cost alternative and that the project's non-economic factors compared favorably with other options, the Company decided to enter into the Hermiston PSA. The decision to accept all output and the subsequent decision to acquire 50% of the facility were intended to pursue low-cost resources as they occurred and present better opportunities compared to analytical results reported in the least-cost plan.

Supporting document references regarding the assessment and evaluation of alternatives include:

- November 1992 Report entitled "Evaluation Process and Results of Supply Side Resources" from PacifiCorp's 1991 Request for Proposals (A.8)
- August 18, 1993 presentation to the PacifiCorp Board of Directors (F.8)
- Sections 3 and 4 of the RMI Hermiston Study (F.10) discuss the process followed by PacifiCorp in evaluating alternatives during the period the decision was made to acquire the Hermiston resource. Page 4-4 of the RMI Hermiston Study identifies the generating resource proposals that were considered by PacifiCorp during 1992-93. PacifiCorp's analysis at the time showed that the estimated cost of power from the least costly of the RFP gas-fired projects was 84% of PacifiCorp's then current avoided costs, as compared with 73% of avoided costs for the estimated cost of power from Hermiston and 76% of avoided costs for the estimated power costs from the Cowlitz project. Pages 4-4 and 4-5 of the RMI Hermiston Study describe the other potential resources that were being considered in Board of Directors presentations in April 1993.
- Pages 3-11 through 3-13 of the RMI Hermiston Study (F.10) discuss the relative costs of the Hermiston, Cowlitz, and other generating projects known to PacifiCorp at the time the decision to enter into the Hermiston PSA was made. Table 3-4 on page 3-13 compares the 20-year levelized costs of Hermiston versus other projects, stated in January 1996 dollars. This table shows that the levelized costs for Hermiston were the lowest among the projects offered to PacifiCorp.
- Resource Management International, Inc. concluded that "Hermiston's estimated 20-year gross resource costs (in levelized 1996 $/MWh) were lower than those of several other projects offered to PacifiCorp at the time the decision to enter into the Hermiston power sale agreement was made." (Reference Document F.10 at ES-2.)
- Indexed documents in Attachment N under category entitled "Analyses of Alternatives" (F.12)

3.5.3 Decision-Making Process

As already indicated, PacifiCorp eliminated other alternatives (with the exception of the Cowlitz project) because the Hermiston facility was the least-cost alternative available at that time. In reaching this conclusion and in deciding to proceed with Hermiston, PacifiCorp's Board of Directors considered substantial information on cost reasonableness. Included in this information were the following:

- Hermiston's power prices were 9% lower than any prices offered in response to the 1991-92 RFP process, 27% lower than the Company's 1993 published avoided costs, and lower than PacifiCorp's system average embedded cost of generation and transmission.

- Based on the approximately 20 projects considered by PacifiCorp, Hermiston was the low-cost alternative, with low life-cycle costs in comparison to the life-cycle costs of other resource options. Subsequent comparisons with BPA's Tenaska project were very favorable for Hermiston.
- PacifiCorp opted for a long-term, fixed-price fuel supply contract rather than a market-based pricing arrangement. The Company pursued this arrangement as a means to mitigate risks related to fuel cost.
- Hermiston's gas costs were lower than other projects submitted through RFP and comparable projects such as the Tenaska/BPA cogeneration project. Similarly, the 5.5% (nominal) annual energy cost escalation rate, fixed for the first 15 years, was within the range of fuel cost escalations utilized in other projects submitted in response to the RFP issued by the Company and the Tenaska project. According to the Company, the gas contracts provide flexibility in that the gas supply, and therefore the plant, can be dispatched to match load requirements. The gas contracts also allow PacifiCorp to use a portion of the gas deliveries elsewhere on its system. In its 1997 report, Resource Management International, Inc. determined that the fuel supply contracts were reasonable.
- According to the Company, Hermiston's fuel costs were considerably lower than the projected gas prices used in RAMPP-2 and RAMPP-3, which reflected a significant benefit associated with securing a long-term gas supply at a fixed contracted price.

The benefits for PacifiCorp's Washington customers arising from the Company's acquisition of the Hermiston facility include the following:

- Initially, the customers were shielded from the risk of financing and building new generation (risks include construction cost overruns, construction delays, permitting delays, and interest rate increases).
- The projected power costs for Hermiston were below the average system cost of PacifiCorp and below the average system cost of several Western utilities.
- The Company claims that it was able to lock in long-term gas supplies at a low fixed rate and that the PSA contributes toward optimal scheduling of power output.
- The cogeneration facility uses clean fuel, which satisfies the goal of implementing environmentally sound power generation.
- In the Company's view, the acquisition of the Hermiston facility further diversified the Company's resource mix.

Supporting document references related to decision criteria and analysis of project costs for the Hermiston cogeneration project include:

- Indexed documents in Attachment N under category entitled "Analyses of Project Costs" (F.12)

- Sections 3 and 4 of the RMI Hermiston Study (Reference Document F.10) discuss the process followed by PacifiCorp to analyze the cost-effectiveness of the Hermiston resource during the period the decision was made to acquire that resource. A summary of the costs under the PSA is presented at pages 3-7 and 3-8, followed by a discussion of the ownership costs of the project on pages 3-8 through 3-11. On pages 3-11 and 3-12, the life-cycle of the Hermiston project is compared with the costs under a Power Purchase Agreement signed in July 1992 between BPA and Tenaska. Table 3-3, page 3-12, shows how much lower Hermiston's per-unit cost of delivered power was compared to the Tenaska/BPA agreement.
- Pages 4-7 through 4-10 of the RMI Hermiston Study (Reference Document F.10) discuss PacifiCorp's resource acquisition process as it relates to the Hermiston project. The Resource Management International, Inc. study shows that fuel costs for Hermiston were lower than gas prices based on RAMPP-2 and RAMPP-3. The nominal 5.5% escalation rate used in securing the long-term gas contract was lower than estimates of escalation rates by the Energy Information Administration, DRI/McGraw Hill Winter, Gas Research Institute, and other projects approved by the Oregon Public Utility Commission.
- As discussed in sections 3 and 4 of the RMI Hermiston Study (Reference Document F.10), PacifiCorp continued to evaluate the costs of the Hermiston resource following its acquisition decision. PacifiCorp entered into the PSA to purchase 100% of the Hermiston output for 20 years on October 7, 1993. A January 1994 analysis compared the gas prices under the Hermiston agreement to contract prices for natural gas for the BPA/Tenaska project. A savings of between $0.25 to $0.37/mmbtu in 1996 associated with the Hermiston fuel contracts compared with BPA/Tenaska's contracts was computed. (Reference Document F.10 at 3-7.)

As already indicated, PacifiCorp's Board of Directors determined that Hermiston was the least-cost alternative and chose to pursue both the Hermiston and Cowlitz projects. The Board of Directors considered considerable information, including a number of formal presentations, before reaching its conclusion. As relevant to Hermiston, significant presentations occurred in April, August, and November 1993.

In the April 1993 presentation, the Board of Directors reviewed the Company's power supply and resource mix and discussed several different potential resources (including Hermiston and Cowlitz). In August 1993, the Board of Directors was shown forecasts indicating capacity deficits beginning in 1995. The August presentation also included information on PacifiCorp's energy resource mix, and a determination was made to diversify the Company's resource portfolio by adding new natural gas generation.

The August presentation also involved a discussion of the identified risks associated with the Hermiston project. In the presentation, seven of these risks were determined to be the responsibility of the developer: (i) siting and permitting; (ii) construction and financing; (iii) fuel supply, transportation, and pricing; (iv) electric transmission; (v) project performance; (vi) FERC filings; and (vii) failure of steam host. Only three of the risks were determined to be the responsibility of PacifiCorp: (i) political fallout, (ii) rating agency issues, and (iii) oversupply of power.

At the November 1993 meeting, the Board of Directors was provided with extensive information about the Hermiston project. The presentation materials included an assessment of allocated risks and benefits, a comparison of resource costs and market prices, and information on non-price considerations.

As the decision-making process proceeded for both Hermiston and Cowlitz, the level of analysis became more detailed. Succeeding presentations to the Board of Directors evaluated additional levels of risk and benefits for each project, applied the RAMPP-2 planning criteria, and addressed other issues such as the risks of these projects versus the risks of wholesale purchases from BPA. Throughout this process, Hermiston and Cowlitz were the least-cost alternatives.

After August 1993, when the Board of Directors decided to pursue both the Hermiston and Cowlitz projects, the Board of Directors was provided price comparisons between (i) Hermiston, (ii) Cowlitz, (iii) the Company's avoided costs, (iv) a combined-cycle combustion turbine project, and (v) projected wholesale prices. The costs for both Hermiston and Cowlitz compared favorably with the costs of other options.[69]

Supporting document references regarding the decision-making process include:

- April 1993 presentation to PacifiCorp Board of Directors regarding power supply issues (F.7)
- August 18, 1993 presentation to the PacifiCorp Board of Directors (F.8)
- November 1993 presentation to the PacifiCorp Board of Directors (F.9)
- Indexed documents in Attachment N under category entitled "Board Presentations and Supporting Analyses" (F.12)

3.5.4 Staff's Assessment of Prudency of the Hermiston Cogeneration Project

The modeling result in RAMPP-2 showed that the Company required about 300 MW from a cogeneration plant by 1997, and peaking resources of up to 600 MW. In response to these resource needs, RAMPP-2 recommended that the Company pursue both near- and long-term acquisition plans.

PacifiCorp issued an RFP in 1991 and 1992 and reviewed and considered approximately 20 resource acquisition opportunities in 1992 and 1993. The process was a fair bidding system open to potential projects that met the criteria outlined in the RFPs. The

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[69] November 1993 Board Presentation, Reference Document I.

decision criteria were that of least cost, diversity mix requirements, and system load requirements as evaluated in RAMPP.

Price comparisons between short-listed projects (*e.g.*, Hermiston and Cowlitz), the Company's filed avoided costs, a combined-cycle combustion turbine project, and projected wholesale prices showed that power cost from Hermiston was 73% of avoided costs of PacifiCorp's then current avoided cost compared with all least-cost projects submitted through the RFP. Furthermore, Hermiston's power prices were 9% lower than any prices offered in response to the 1991-92 RFP process. Therefore, Hermiston was a low-cost project.

The Hermiston project, a 470-MW natural gas-fired cogeneration facility, was planned to be used as a base load resource. Therefore, it is important to make sure that risks related to its operation are minimized. The major source of risk is fluctuation in gas prices. As a result, the company signed a long-term, fixed-price fuel supply contract rather than a market-based pricing arrangement. The fuel costs used in the Hermiston project were about 30% lower than projected gas prices used in RAMPP-2 and RAMPP-3, with an escalation factor that was about 30% less than escalation factors in 1992. As a result of these arrangements, the project was able to save \$0.25 to \$0.37/mmbtu in 1996 compared with comparable projects such as BPA/Tenaska's.

The acquisition of Hermiston is prudent, to the extent that the following have been demonstrated: need or demand for the load, having a fair bidding procedure, satisfaction of the least-cost criteria of the resource plan, and favorable comparison to available alternatives. This conclusion is relevant so long as the acquisition of the resource is evaluated on a system-wide basis.

3.6 ACQUISITION OF WYOMING WIND PROJECT

The Foote Creek, Wyoming Wind Plant Project (the "Wyoming Wind Project") is one of the largest wind plants in the West. It is a 41.4-MW wind-powered electric generation facility located along the Foote Creek rim between Laramie and Rawlins, Wyoming. Powered by 69 wind turbines, the Wyoming Wind Project is capable of generating electricity to serve as many as 25,000 customers. The Wyoming Wind Project was completed on April 22, 1999 and provides clean, renewable electric energy while advancing the science of wind power.

The Wyoming Wind Project was developed by ToyoWest, Wyoming, LLC and is operated and maintained by SeaWest Wyoming, LLC. PacifiCorp and EWEB own the Wyoming Wind Project's generating facilities. PacifiCorp owns nearly 80% of the project, and EWEB owns the remainder.

The Wyoming Wind Project also involved construction of a 29-mile-long 230-kV radial transmission line from the Foote Creek Rim substation to PacifiCorp's miner's substation. The 230-kV transmission line and additional installed step-up transformers are capable of radial net transmission of at least 150 MW. Other wind projects at Foote Creek also use PacifiCorp's transmission lines, which results in a reduction of PacifiCorp's incurred project costs.

Supporting document references regarding the acquisition of the Wyoming Wind Project include:

- May 19, 2000 PacifiCorp supplemental response to WUTC Staff Data Request No. 201 (E.1)
- March 7, 1994 Amended and Restated Development Agreement among Eugene Water & Electric Board, PacifiCorp, ToyoWest Wyoming, LLC and guarantors SeaWest Power Systems, Inc. and Tomen Corporation (E.2)
- September 7, 1994 Applied Power Concepts, Inc. Certificate as to Design Specifications and Windplant Design (E.3)
- September 1997 PacifiCorp Fact Sheet, "Tapping the Power of Wind" and SeaWest fact brochures
- January 5, 1998 Project Plan Document (E.4)
- September 3, 1998 Bonneville Power Administration Wyoming Wind Project Expansion Agreement (E.5)
- October 12, 1998 Generation Control, Storage and Firm Power Supply Agreement between Eugene Water & Electric Board and PacifiCorp (E.6)
- October 15, 1998 PacifiCorp filing with FERC regarding Wyoming Wind Project (E.7)
- December 8, 1998 FERC Acceptance of Filing (E.8)
- April 26, 1999 Letter to Walt George, Bureau of Land Management from Steven M. Thompson, SeaWest Energy Land Associates, LLC, regarding Right of Way WYW-142464 Foote Creek Rim, Wyoming (E.9)
- Indexed documents in Attachment T under category entitled "Contract Negotiations" (E.11)

3.6.1 Demand for Wyoming Wind Project

3.6.1.1 Results from RAMPP

PacifiCorp recognized a need to further diversify its resource portfolio and to acquire knowledge and experience with renewable technologies that can be gained only through actual hands-on experience. PacifiCorp pursued renewables such as wind generation, although they have not compared favorably with costs of conventional types of generation. The comparison of generation resource alternatives is discussed in RAMPP reports.

PacifiCorp claims that it utilizes integrated resource planning in order to guide future supply-and-demand decisions and to determine how to meet future energy needs at the least cost to the Company and to its customers. The RAMPP action plans contain specific references to the development of renewable resources, including wind generation projects.

In 1989, RAMPP-1 cited the need to develop information on potential renewable resources in order to meet long-term requirements in a cost-effective manner. The action plan included geothermal, wind, and solar energy as potential future renewable resources. In 1992, the Company completed RAMPP-2, which included a new environmental goal that required the Company to continue to explore renewable resources as a potential energy source. RAMPP-2's action plan called for the Company to have 125 MW of wind capacity in operation by 1996-97 to help meet projected growing summer peak loads.

This same course of action was continued in 1994 with RAMPP-3, which referenced the Company's 1993 Strategic Environmental Goal to have 50 MW of renewable resources on-line by 1996. The RAMPP-3 action plan also realized the need to gain operating experience with renewable technologies. RAMPP-3 presented a specific set of steps to follow with the Wyoming and Columbia Hills wind projects (another wind project that has been discontinued by the Company) in order to determine the future feasibility and cost-effectiveness of wind generation. RAMPP-3 included the following discussion of the Wyoming Wind Project:

> PacifiCorp has also contracted with Kenetech Windpower for a 50 MW plant in Carbon County, Wyoming. Kenetech Windpower will build the plant with PacifiCorp as principal owner. The Eugene Water and Electric Board, Tri-State Generation and Transmission Association, and Public Service Company of Colorado are also considering participating. If each of these companies participates to the full level of their preliminary request, the project will become 70.5 MW. The steady winds of Wyoming offer 30 to 50 percent more energy potential than sites in the Pacific Northwest. BPA will buy 25 MW of the output and PacifiCorp and the other owners will take some of the output for their own customers. PacifiCorp will get 25 MW for its own use. The project offers opportunities for staged development: PacifiCorp could expand its involvement if the initial project is cost-effective and successful. If transmission limitations are overcome, sufficient wind towers at the Wyoming site could produce several hundred MW. The project should begin producing power in 1996.[70]

In November 1995, the Company completed RAMPP-4. While the cost of renewable resources continued to exceed the cost of coal-fired resources, in the Company's view it was important to continue to pursue low-cost activities in order to increase its knowledge about renewable resources. The Wyoming Wind Project was one such low-cost project in development. The Company also continued to explore the potential for, and the cost-effectiveness of, other wind projects.

In December 1997, the Company's RAMPP-5 focused on the coming 10 years as impacted by the changing nature of the electric industry and the influx of competition in the market. Environmental concerns such as global warming provided the stimulus to explore renewable resources. RAMPP-5 included the pursuit of cost-effective resource acquisition

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[70] RAMPP-3 at 230.

opportunities, including renewables to address customers' increasing interest in green power. The Wyoming Wind Project, then in its construction phase, represented one example of cost-effective renewable resource acquisition. RAMPP-5 included the following discussion of the Wyoming Wind Project:

> The decrease in capacity [in total wind generation] is due to the indefinite postponement of the Columbia Hills wind project. Both PGE and PacifiCorp canceled the contracts they had with Kenetech Windpower due to avian issues. Kenetech has entered Chapter 11 bankruptcy proceedings, and may sell their project assets to another entity at some time in the future. For the Wyoming project, both Public Service of Colorado and Tri-State Generation and Transmission have dropped out of the project. Tri-State's 33-member board of directors did not approve moving forward with the project. The remaining owners are Eugene Water & Electric Board, and PacifiCorp who remain committed to the project. The project size is now approximately 42 MW, reflecting a reduction due to the shares that were to be owned by PSCo and Tri-State. BPA continues to be committed to the project and will be purchasing 15.32 MW of the output. All permits have been received and construction began in August of 1997. Completion is scheduled for the fall of 1998, well ahead of the expiration of production tax credits that expire on June 30, 1999.[71]

In RAMPP-5, PacifiCorp further stated that discussions were held with other wind developers and that the Company continued to evaluate other potential wind projects. In 1996, "no proposed projects were cost effective compared to alternatives."[72]

Supporting document references regarding demand for the Wyoming Wind Project include:

- RAMPP-1 "Planning for Stable Growth," Volume 1 - Summary Report (A.1)
- RAMPP-2 "Balanced Planning for Growth" Excerpts (A.2)
- RAMPP-3 "Positioning for Competition and Uncertainty" Excerpts (A.3)
- RAMPP-4 "Flexible Choices for a Changing Market" Excerpts (A.4)
- RAMPP-5 "PacifiCorp Resource and Market Planning Program" Excerpts (A.6)
- Indexed documents in Attachment T under category entitled "Resource Planning/Need for Power" (E.11)

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[71] RAMPP-5 at 108.

[72] RAMPP-5 at 158.

3.6.1.2 Impact on DSM Resources, System Optimality

PacifiCorp's integrated resource planning process includes an analysis of DSM resources in addition to supply-side resources. DSM resources include implementing conservation measures and increasing the energy efficiency of new and existing buildings. The level of demand-side resources varies with the load forecast, because estimates of potential savings depend on the forecast used, as well as on detailed end-use information. The amount of electricity that can be saved through energy-efficiency measures is directly tied to the number of homes, businesses, and industries served.

Demand-side resources are not directly affected by the acquisition or development of a particular resource. At the same time, lower costs of supply-side resources affect the level of DSM. For example, RAMPP-4 added less DSM than RAMPP-3 at the medium DSM level due to two primary changes: lower system needs and lower costs of new supply-side resources that were competitive with DSM. The lower costs of new supply-side resources reduced the level of cost-effective DSM from 23 aMW in RAMPP-4 to 15.7 aMW in RAMPP-5.

Resource acquisition opportunities rarely involve a simple numerical comparison of one resource to another. Instead, such opportunities represent a chance to achieve potential benefit from the diverse load and resource characteristics within the region and with other regions. Generally, the RAMPP model forecasts first select demand-side resources to fill the Company's resource needs and then select the next most cost-effective resource. Adding demand-side resources reduces the remaining energy and capacity needs that must be met by other resources. Because of the Company's environmental objectives, the models also selected renewable resources.

The Wyoming Wind Project was completed in April 1999, just a few months before the RAMPP-6 interim report was completed. There, the latest-generation information reflected that the project exceeded projected MWh by 28.1% in April 1999, 15% in May 1999, and 0.1% in October 1999.[73] For summer months the actual MWh was lower than projected. The Company continues to evaluate project optimality and performance.

Supporting document references regarding the impact on DSM and system optimality of the Wyoming Wind Project include:

- RAMPP-2 "Balanced Planning for Growth" Excerpts (A.2)
- RAMPP-3 "Positioning for Competition and Uncertainty" Excerpts (A.3)
- RAMPP-4 "Flexible Choices for a Changing Market" Excerpts (A.4)
- RAMPP-5 "PacifiCorp Resource and Market Planning Program" Excerpts (A.6)
- September 1997 PacifiCorp Fact Sheet, "Tapping the Power of Wind"
- RAMPP-6 "Interim Report" Excerpts (A.7)
- Indexed documents in Attachment T under category entitled "Project Operation Performance" (E.11)

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[73] RAMPP-6 Interim Report, Appendix B at 7-18.

3.6.2 RFPs and the Resource Acquisition Process

After weighing the potential costs and benefits, the Company's senior management decided to pursue pilot renewable projects as part of the Company's environmental goal. The Company's approach was to take advantage of the opportunity to acquire renewable resources at competitive prices through negotiations with developers that approached the Company rather than through a Green RFP or Renewable Set-Aside in an open RFP. Developers were continually approaching PacifiCorp with proposals for specific projects. The Wyoming Wind Project was initiated through such a process and is expected to provide diversity of resource mix and greater knowledge in power generation from renewable technologies.

Supporting document references regarding the RFP and acquisition process as it relates to the Wyoming Wind Project include:

- PacifiCorp's 1991 Request for Proposals (A.8)
- RAMPP-2 "Balanced Planning for Growth" Excerpts (A.2)
- RAMPP-3 "Positioning for Competition and Uncertainty" Excerpts (A.3)

In addition to the Wyoming Wind Project, the Company also considered developing the Columbia Hills Wind Project. Kenetech Windpower, Inc. ("Kenetech") began to develop the Columbia Hills Wind Project and obtained the necessary permits for the project before Kenetech declared bankruptcy. The Columbia Hills project was to be jointly owned by Portland General Electric ("PGE") and PacifiCorp. Although Kenetech obtained the necessary permits, the project was determined to be unacceptable to PacifiCorp and PGE because of avian mortality concerns. PacifiCorp and PGE therefore terminated the contracts for the project but were interested in discussing a power sales arrangement with a new developer. Kenetech did not actively pursue a sale of the assets of the project because of a lack of interest in a project without utility participation.

PacifiCorp continued to evaluate other potential wind projects and to pursue agreements for cost-effective projects. In 1996, when the Wyoming Wind Project was in its development stages, there were no other comparable cost-effective proposed projects.

A growing number of customers value the environmental benefits of electricity generated by renewable energy, or "green power." In the Company's view, the Wyoming Wind Project contributes to a cleaner environment in the Pacific Northwest because wind power generation produces no air emissions. PacifiCorp's development of wind and other renewable resources is intended to satisfy the Company's goals of resource diversity, low cost, and environmental benefits as discussed in its resource plan. It is capable of serving consumer demand by providing clean and renewable energy to as many as 25,000 PacifiCorp customers. As an additional benefit, the knowledge and experience gained from the Wyoming Wind Project will assist future wind projects in the Pacific Northwest.

Supporting document references related to the assessment and evaluation of the alternatives include:

- RAMPP-3 "Positioning for Competition and Uncertainty" Excerpts (A.3)
- RAMPP-4 "Flexible Choices for a Changing Market" Excerpts (A.4)
- RAMPP-5 "PacifiCorp Resource and Market Planning Program" Excerpts (A.6)

3.6.3 Decision-Making Process

In RAMPP-1, PacifiCorp estimated a total levelized resource cost for a wind plant at 45.7 mills.[74] Capacity costs were estimated to range from $1,588 to $2,647 per installed kW.[75] Wind resources were compared with other options available to PacifiCorp as short-term and long-term options.[76]

In RAMPP-2, the levelized cost for a wind project was estimated at 48.77 mills to 61.69 mills.[77] Table 4-14 showed a cost of 55.88 mills/kWh for a 2001 in-service date.

In RAMPP-3, the cost estimates reflected the contracts with Kenetech for wind farms in Washington and Wyoming. It has also been shown that the cost of the Wyoming Wind Project (without a federal income tax credit) is 65.57 mills/kWh in 1994 dollars.[78]

The expected costs from the Columbia Hills and Foote Creek developments are reflected in RAMPP-4.[79] The total cost associated with the Wyoming Wind Project was listed at 48.40 mills (firm) and 38.78 mills (nonfirm), respectively.[80] According to RAMPP-4, the "real levelized cost of wind resources varied between about 39 and 57 mills/kWh," which included the effect of a federal tax credit of 1/5 cents per kWh for each kWh generated during the first 10 years of wind operation, if the plant is on-line by July 1, 1999.[81]

RAMPP-5 estimated a total resource cost for the Wyoming Wind Project of 64.03 mills/kWh.[82]

The RAMPP-6 interim report stated that the project began generating electricity in fall 1998.[83]

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[74] RAMPP-1, Table 40.
[75] RAMPP-1, Table 16.
[76] RAMPP-1, Tables 39 & 40.
[77] RAMPP-2, Table 3-7.
[78] RAMPP-3, Table 4-7.
[79] *See* RAMPP-4 at 82-83.
[80] Table 3-20.
[81] RAMPP-4 at 91.
[82] RAMPP-5, Table 4-19.
[83] RAMPP-6 interim report at Appendix D provides a summary of the 1997 generation information.

PacifiCorp was able to recoup some of the costs of the Wyoming Wind Project through state incentive programs. For example, Oregon's renewable incentive program allowed the Company to allocate $201,364 of its share of the project costs to the program.

Supporting document references related to the decision criteria and analysis of project costs include:

- Section 6.1 of the Amended and Restated Development Agreement (E.2)
- July 21, 1997 Bonneville Power Administration Wyoming Wind Plant Project Power Purchase Agreement and BPA Record of Decision (E.10)
- RAMPP-4 "Flexible Choices for a Changing Market" Excerpts (A.4)
- RAMPP-5 "PacifiCorp Resource and Market Planning Program" Excerpts (A.6)
- RAMPP-6 "Interim Report" Excerpts (A.7)
- Indexed documents in Attachment T under category entitled "Analysis of Project Costs" (E.12)
- Indexed documents in Attachment T under category entitled "Due Diligence" (E.12)

For a number of years, PacifiCorp has included in its strategic goals specific references to the development of environmental resource alternatives and the diversification of resources. Wind generation projects are among the specific renewable resource projects identified in the Company's RAMPP documents.

PacifiCorp has taken numerous actions that relate to the cost-effectiveness of wind resource development. PacifiCorp received substantial meteorological information from the original site developer that concluded the site was one of the best wind resources within the United States. An independent meteorologist retained as a consultant by PacifiCorp supported this conclusion. The site is estimated to have the capability of supporting 500 MW of wind generation. The characteristics of the site thus ensure maximum output from the project. Most wind generation projects within the United States have a capacity factor of approximately 30%, while the capacity factor for the PacifiCorp project is estimated at 42.6%. The average wind speed at Foote Creek rim is 24 to 26 miles per hour, while the average wind speed at most wind resource sites is below 20 miles per hour.

PacifiCorp reduced risks of the project by sharing ownership responsibilities with EWEB. The Company further minimized project risks by executing the power purchase agreement with BPA, thus assuring sale of a definitive amount of project output. Also, the addition of EWEB as an owner and BPA's commitment to purchase a portion of the project's output allowed PacifiCorp to build a larger project with a corresponding lower cost per kW than would have been the case with a smaller-scale project.

PacifiCorp conducted due diligence on SeaWest Energy Corp. ("SeaWest") (the parent of ToyoWest LLC) when it acquired the rights to develop Foote Creek rim from Kenetech. In addition, PacifiCorp hired a technical consultant to assist in the due diligence effort on the

Mitsubishi wind turbines that SeaWest identified as the most appropriate for the windy and cold Wyoming environment. PacifiCorp was able to negotiate a 10-year warranty on the turbines from the parent company, Mitsubishi Japan, which protects the Company from the risks of turbine failure.

PacifiCorp negotiated provisions with the project developer under which the project will be tested for three years after coming on-line. If the project does not meet the output standards established in the development agreement, the developer is obligated to rebate a pro rata share of the purchase price.

PacifiCorp negotiated agreements with both BPA and EWEB under which these entities pay PacifiCorp 6 mills per kWh for storage services, thereby further mitigating PacifiCorp's generation and transmission costs. This storage charge may be revised based on changes in the effective resource pool for PacifiCorp's FERC Electric Tariff, Original Volume No. 3. Construction of the project provided PacifiCorp with additional opportunities to mitigate project costs. BPA constructed three turbines at the site (Foote Creek 2) producing two MW of power. PSCo constructed 33 turbines capable of producing 25.2 MW of power on the Foote Creek rim site (Foote Creek 3). PacifiCorp executed an agreement with PSCo under which PSCo will pay PacifiCorp storage and delivery charges. BPA is in the last stages of negotiations for Foote Creek 4, which, if developed, will involve construction of additional wind turbines capable of producing approximately 16.8 MW of additional power. The PSCo and BPA payments for PacifiCorp providing transmission services from the project will defray a substantial share of PacifiCorp's incurred costs.

Supporting document references related to the decision-making process include:

- RAMPP-1 "Planning for Stable Growth," Volume 1 - Summary Report (A.1)
- RAMPP-2 "Balanced Planning for Growth" Excerpts (A.2)
- RAMPP-3 "Positioning for Competition and Uncertainty" Excerpts (A.3)
- RAMPP-4 "Flexible Choices for a Changing Market" Excerpts (A.4)

3.6.4 Staff's Assessment of Prudency of the Wyoming Wind Project

In addition to the RAMPP reports demonstrating the need for new generation resources to meet growing system demand, the reports also emphasized the need to develop information on potential renewable resources in order to meet long-term requirements in a cost-effective manner. The reports indicated geothermal, wind, and solar energy as potential renewable resources. For example, RAMPP-2 and -3 demonstrated the need to acquire 125 MW and 50MW of wind capacity and renewable resources in operation by 1996-97 and 1996, respectively, to help meet projected growing summer peak loads.

The Company thought to take advantage of the opportunity to acquire renewable resources at competitive prices through negotiations with developers that approached the Company rather than through a Green RFP or Renewable Set-Aside in an open RFP. The

Wyoming Wind Project was initiated through such a process. There was no RFP issued to acquire renewable resources during the time the Company planned to acquire Foote Creek.

The Wyoming Wind Project is one of the largest wind plants in the West. It is a 41.4-MW wind-powered electric generation facility located along the Foote Creek rim between Laramie and Rawlins, Wyoming. The project is capable of generating electricity to serve as many as 25,000 customers. As an added benefit, the knowledge and experience gained from the Wyoming Wind Project will assist future wind projects in the Pacific Northwest.

The Company's RAMPP reports estimate a total levelized resource cost for a wind plant at 46 to 66 mills/kWh. In RAMPP-4, the total cost associated with the Wyoming Wind Project was listed at 48.40 mills (firm) and 38.78 mills (nonfirm), respectively. Thus the Wyoming Wind Project can be assumed to be a low-cost resource compared to prices estimated in the RAMPP reports.

The company pursued various options to recoup investments and minimize risk. These include (i) acquiring funds from the state incentive programs, (ii) sharing ownership responsibilities with EWEB, (iii) executing the power purchase agreement with BPA, (iv) negotiating a 10-year warranty on the turbines from Mitsubishi, and (v) negotiating provisions with the project developer such that if the project does not meet the output standards established in the development agreement, the developer is obligated to rebate a pro rata share of the purchase price.

Staff believes that projects of this nature not only improve the resource mix of the Company but also present a low-cost peaking alternative. Although Staff is concerned that there was no open bidding, Staff did not find evidence that the Company foreclosed other opportunities that were comparable to this wind project. Thus Staff is of the opinion that the project was acquired prudently to satisfy system-wide resource needs.

CHAPTER IV: CONCLUSIONS AND SUMMARY

The Stipulation approved by the Commission in its Third Supplemental Order in Docket No. UE-991832 states as follows with respect to the demonstration required by the Company in its next general rate proceeding:

> The Company will be required to make an affirmative showing in the direct testimony and exhibits of its next general rate proceeding demonstrating the prudence of those resources acquired since its previous general rate case (Cause No. U-86-02) which it proposes to include in rates in such proceeding.

Through this prudence review process, the participating parties (Staff, Public Counsel, and ICNU) have had an opportunity to review the information provided by the Company that would comprise the Company's direct case in such a proceeding as it relates to the acquisition of the specified resources between its 1986 general rate case and its 1999 general rate case. The acquisitions that are the subject of this Joint Report have been subject to third-party verification and public review.

In resource planning for the future, the first question is "How much power will customers need in the future?" PacifiCorp's RAMPP forecasted a range of load-growth possibilities. In 1989, for example, the Company projected medium-load growth rate to increase at an annual rate of 1.6%. Between 1989 and 2008, load was projected to increase from 4,861 aMW to 6,557 aMW.[84] The total forecasted resource requirement was 1,398 aMW. Due in part to changes in the industry and the acquisition of resources, RAMPP-6, issued on December 31, 1999, reflects that the Company does not anticipate that it will need new resources until 2005-06 and will not need to make a decision regarding the acquisition of additional resources until 2003-04.

In summary, the Company makes use of its least-cost plan to guide decisions regarding the acquisition of resources. Projected resource acquisition for a medium-case scenario in the 1989 RAMPP report (RAMPP-1) indicated a need for about 1,398 aMW.[85] Analysis of resources acquired by 1999 indicated that the Company has satisfied approximately 80% of its projected resource requirement. Moreover, investigation of the sales (load) and customer data in 1999 compared with 1986 indicated an increase of 36% and 25%, respectively. The percentage share of new resources acquired between 1989 and 1999 (1,154 aMW) compared with projected load growth was about 24%. These empirical results indicate that the acquisition of resources seem to be in congruence with increases in load and customer growth.

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[84] RAMPP-1 at 12.

[85] *See* Table 2.

PacifiCorp utilized the least-cost plan to guide its decisions regarding the need to acquire new resources. The 1991 RFP process implemented low-cost bids while satisfying other requirements.

Craig and Hayden, Cholla Unit No. 4, James River, Hermiston, and Wyoming Wind together result in the production of 1,154 aMW to the Company's system. For each of the projects, this report discusses and provides support for the system-wide need for the resource, consideration of alternatives, reasonableness of resource costs, information and analysis presented to the Company's Board of Directors, and the process of acquisition. The Company followed the procedures outlined in the Third Supplemental Order to facilitate the prudence review. This report provides a summary of information that was used for the prudence review. Accordingly, this Joint Report satisfies the requirements of the Third Supplemental Order.

Based on a template that was provided to the Company, Staff received information on projects acquired since 1986. Pursuant to the Third Supplemental Order, Staff evaluated the information submitted in order to determine the prudency of resource acquisition. Specifically, the information presented to Staff was evaluated with respect to whether (i) resources acquired were necessary or intended to satisfy the projected demand, (ii) the resource was acquired at least-cost compared to alternatives considered or relative to own-avoided cost of production, (iii) the acquisition of the resource unduly affected the need for DSM programs, and (iv) the acquisition process was fair.

Based on the information provided, Staff believes that the resources were acquired prudently when evaluated from a system-wide basis. Staff did not investigate whether the resources were acquired to satisfy the demand of Washington customers. These resources could be subjected to investigations in future rate case proceedings that will determine whether these resources were acquired prudently to satisfy increased load growth or demand in Washington State, including consideration of the Company's commitments under merger agreements and orders, the impact of the "interjurisdictional" allocation used by the Company, and particular load-growth characteristics of the Company's Washington service territory.

CHAPTER V: REFERENCES

The following documents support this Joint Report and have been previously provided to the parties in this docket. Copies of the references are also available for inspection and copying at the Seattle offices of Stoel Rives LLP.

A. Reference Documents Relating to All Acquisitions

1. RAMPP-1 "Planning for Stable Growth"
2. RAMPP-2 "Balanced Planning for Growth"
3. RAMPP-3 "Positioning for Competition and Uncertainty"
4. RAMPP-4 "Flexible Choices for a Changing Market"
5. RAMPP-4 Update "1997 IRP Report"
6. RAMPP-5 "Resource and Market Planning Program"
7. RAMPP-6 "Interim Report"
8. PacifiCorp's 1991 Request for Proposals - November 1992 Report entitled "Evaluation Process and Results of Supply Side Resources"

B. Reference Documents Related to Cholla Unit No. 4 Acquisition

1. October 11, 1990 Letter Agreement
2. Asset Purchase and Power Exchange Agreement
3. Cholla Unit 4 Operating Agreement
4. Long-Term Power Transactions Agreement
5. Transmission Agreement
6. Operating Exchange Agreement
7. PacifiCorp Analysis of APS Transactions
8. PacifiCorp Avoided Cost Analysis of Cholla Unit 4 Acquisitions
9. September 14, 1990 Presentation to Board of Directors

10. February 20, 1991 Presentation to Board of Directors

11. Map of Proposed Transmission Arrangements

12. Arizona Corporation Commission Staff's Notice of Filing of Agreement of Settlement and Stipulation, Docket No. U-1345-90-269

13. July 11, 1991 Arizona Corporation Commission Order, Docket No. U-1345-90-269

14. RMI Evaluation of PacifiCorp's Acquisitions of Facilities from Arizona Public Service Company and Colorado-Ute Association, Volumes I and II

15. Index of remaining Cholla Unit 4 Acquisition documents

C. Reference Documents Related to Craig and Hayden Acquisitions

1. Asset Purchase and Power Exchange Agreement

2. Funding and Disbursement Agreement

3. February 20, 1991 Presentation to PacifiCorp Board of Directors

4. PacifiCorp Analysis of Colorado-Ute Transaction

5. Accounting Petition of PacifiCorp before the Washington Utilities and Transportation Commission

6. Testimony and Exhibits of Dennis P. Steinberg in Support of Accounting Petition

7. Testimony and Exhibit of Gregory N. Duvall in Support of Accounting Petition

8. Value of Net Resource from Colorado-Ute Transactions (Exhibit GND 4-1 to Duvall Testimony)

9. Comparison of 1992 Real Levelized Life Cycle Costs for Colorado-Ute Net Resource (Exhibit GND 4-2 to Duvall Testimony)

10. Load and Resource Analyses (Exhibit GND 4-3 to Duvall Testimony)

11. Testimony and Exhibits of Anne E. Eakin in Support of Accounting Petition

12. WUTC Order Granting Petition as Amended (Docket No. UE-911186(P))

13. RMI Evaluation of PacifiCorp's Acquisitions of Facilities from Arizona Public Service Company and Colorado-Ute Association, Volumes I and II

14. Index of remaining Colorado-Ute Acquisition documents

D. Reference Documents Related to James River Cogeneration Project

1. Letter of intent regarding Development Agreement from Dennis P. Steinberg, PacifiCorp, to Harry A. Barber, James River Corp., dated October 8, 1992

2. Camas Development, Construction, Operation and Steam Supply Agreement between PacifiCorp and James River Paper Co., Inc., dated January 13, 1993

3. Lease between James River Paper Co., Inc. and PacifiCorp, dated January 13, 1993

4. Transmission Facilities Purchase, Easement and License Agreement between PacifiCorp and James River Paper Co., Inc., dated January 13, 1993

5. SEC Response to PacifiCorp Request for No Action

6. Transmission Line Easement Agreement, dated January 31, 1993

7. June 15, 1992 James River Camas Cogeneration Project Presentation to PacifiCorp Management Council

8. July 22, 1992 James River Camas Cogeneration Project Presentation to Pacific Power Board

9. February 1993 Direct Testimony of Rodger Weaver before the Public Utility Commission of Oregon

10. February 1993 Direct Testimony of Gregory N. Duvall before the Public Utility Commission of Oregon

11. Documents discussing Wauna alternative, including memoranda dated June 1, 1990 and June 12, 1990

12. Index of remaining James River Cogeneration Project documents

13. General File Index of James River Cogeneration Project documents

E. Reference Documents Related to Hermiston Cogeneration Project

1. Long-Term Power Sales Agreement between Hermiston Generating Company, L.P. and PacifiCorp, dated October 7, 1993

2. Option Agreement between Hermiston Generating Company, L.P. and PacifiCorp, dated October 7, 1993

3. Security Agreement between Hermiston Generating Company, L.P. and PacifiCorp, dated October 7, 1993

4. Letter of Credit Agreement between Hermiston Generating Company, L.P. and PacifiCorp, dated October 7, 1993

5. Letter Agreement requiring Hermiston to have contracts in place by December 31, 1993 for 20 years of transportation and 15 years of natural gas supply

6. Hermiston Project Purchase Agreement between Hermiston Generating Company, L.P. and PacifiCorp, dated December 30, 1994

7. April 1993 Presentation to the PacifiCorp Board of Directors

8. August 18, 1993 Presentation to the PacifiCorp Board of Directors

9. November 1993 presentation to the PacifiCorp Board of Directors

10. RMI Study dated May 1997 entitled "Study of the Acquisition of the Hermiston Co-Generation Facility by PacifiCorp"

11. March 15, 1995 presentation to the PacifiCorp Board of Directors regarding exercise of option to purchase 50% of the Hermiston project

12. Index of remaining Hermiston-related documents

F. Reference Documents Related to Wyoming Wind Project

1. May 19, 2000 Supplemental Response of PacifiCorp to WUTC Staff Data Request No. 201

2. March 7, 1994 Amended and Restated Development Agreement among EWEB, PacifiCorp, and Toyowest Wyoming, L.L.C.

3. September 7, 1994 Certificate as to Design Specifications and Windplant Design

4. January 5, 1998 Project Plan Document

5. September 3, 1998 Wyoming Wind Project Expansion Agreement (Bonneville Power Administration)

6. October 12, 1998 Generation Control, Storage and Firm Power Supply Agreement between EWEB and PacifiCorp

7. October 15, 1998 PacifiCorp Filing at FERC re Wyoming Wind Project

8. December 8, 1998 FERC Acceptance of Filing

9. April 26, 1999 notice of transfer of title from SeaWest to PacifiCorp and EWEB

10. July 21, 1997 Power Purchase Agreement with Bonneville Power Administration and BPA Record of Decision

11. Index of remaining Wyoming Wind Project documents

12. Index of PacifiCorp files for Wyoming Wind Project documents

LIST OF APPENDICES

A. Chronology of Events Related to Resource Acquisitions

Appendix 6.A	Chronology of Events Related to Resource Acquisitions

B. Historical Information Regarding Customer Numbers, Class and Load by State, and Forecasted Customer Loads by State and Class

Appendix 6.B.1	Historical Energy Sales (Gwh) by Class
Appendix 6.B.2	Historical Average Number
Appendix 6.B.3	Forecast Energy Sales (Gwh) by Class
Appendix 6.B.4	Forecast Average Number of Customers by Class

Appendix 6.A

Appendix 6.A
Chronology of Events Related to Resource Acquisitions

Date	Event
October 13, 1989	Harris Group prepares scope and estimate for Camas project for James River
November 1, 1989	RAMPP-1 "Planning for Stable Growth" is completed
February 1, 1990	James River informs PacifiCorp of potential cogeneration projects; PacifiCorp meeting is held to discuss projects, opportunities, risks and costs affiliated with each project
March 1, 1990	NW Pipeline evaluation (James River Cogeneration Project)
March 30, 1990	Colorado-Ute files voluntary petition for Chapter 11 bankruptcy protection
May 9, 1990	PacifiCorp representatives visit James River's Wauna plant (cogeneration option) to gain familiarity with mill steam generation and mill process steam requirements
August 31, 1990	James River releases RFP for development of three potential cogeneration projects including the Camas Cogeneration Project
September 21, 1990	PacifiCorp and APS execute Asset Purchase and Power Agreement, Transmission Agreement and Long-Term Power Transactions Agreement and Cholla Unit 4 Operating Agreement
September 21, 1990	APS files application with Arizona Corporation Commission for authorization to transfer Cholla Unit 4 and related common facilities to PacifiCorp
October 5, 1990	PacifiCorp meets with James River to present PacifiCorp response to James River RFP for development of cogeneration of James River's three Pacific Northwest mills
October 19, 1990	PacifiCorp provides written response to James River RFP solicitation
October 24, 1990	PacifiCorp conducts forecast of possible natural gas prices at James River's Camas, Wauna and Halsey mills

Appendix 6.A
Chronology of Events Related to Resource Acquisitions

Date	Event
December 7, 1990	PacifiCorp files report regarding proposed acquisition of Cholla Unit 4
December 19, 1990	PacifiCorp reviews James River's concepts for 2 stages of generation, (1) steam turbine generator to be installed on completion of new hogfuel boiler and (2) gas turbine/waste heat boiler to be installed at a future date
December 24, 1990	APS files amended application with Arizona Corporation Commission for authorization to transfer Cholla Unit 4 to PacifiCorp
February 27, 1991	PacifiCorp transmits Memorandum of Understanding to James River regarding PacifiCorp's possible acquisition of development rights for all existing and future cogeneration potential at Camas mill
March 19, 1991	FERC approves agreement between PacifiCorp and APS regarding Cholla Unit 4 Acquisition
April 15, 1991	James River transmits revised Memorandum of Understanding to PacifiCorp
April 25, 1991	Electrical Systems Analysis, Inc. (ESA) letter to PacifiCorp regarding impact of James River Camas cogeneration on utility and industrial power systems
May 20, 1991	Hearing before the Arizona Corporation Commission regarding transfer of Cholla Unit 4 from APS to PacifiCorp
June 6, 1991	Meeting between PacifiCorp and James River representatives to discuss objectives and interests of PacifiCorp and James River, status of Memorandum of Understanding and agreement on funding of scope and estimate. Parties agree to proceed on a handshake and to work through Memorandum of Understanding issues
June 18, 1991	PacifiCorp meets with James River at Camas mill to develop pro forma and discuss fuel strategy

Appendix 6.A
Chronology of Events Related to Resource Acquisitions

Date	Event
June 19, 1991	APS, Arizona Corporation Commission Staff and PacifiCorp execute settlement and stipulation regarding transfer of Cholla Unit 4 to PacifiCorp
June 21, 1991	PacifiCorp, Public Service Company of Colorado ("PSCo") and Tri-State Generation and Transmission Association ("Tri-State") enter into Memorandum of Agreement to submit Joint Plan of Reorganization
July 10, 1991	Arizona Corporation Commission approves transfer of Cholla Unit 4 from APS to PacifiCorp
July 10, 1991	PacifiCorp presentation regarding joint cogeneration development at James River's Camas Mill
July 15, 1991	Closing for the Cholla Unit 4 Acquisition
July 15, 1991	PacifiCorp's Environmental Services Department performs environmental due diligence review of James River's Camas site
July 23, 1991	First draft development agreement for James River Cogeneration project
July 26, 1991	ESA completes mill electrical study (James River Cogeneration Project)
July 27, 1991	AH Seekamp PE recommends Harris Group as acceptable engineer for project (James River Cogeneration Project)
July 29, 1991	Initial technical meeting between PacifiCorp, James River and Harris Group representatives at James River Camas mill to discuss design criteria, concept, status, method to evaluate condensing vs. non-condensing turbine
July 31, 1991	Preliminary technical review meeting for steam turbine generator at James River Camas Mill, electrical study is completed

Appendix 6.A
Chronology of Events Related to Resource Acquisitions

Date	Event
August 1991 - January 1993	PacifiCorp and James River draft and negotiate terms of development agreement
August 21, 1991	APS Transaction Study is presented to the Public Service Commission of Utah. The study represents analysis of total revenue requirements for the Cholla Unit 4 Acquisition
September 5, 1991	PacifiCorp and James River meet to discuss financial structure for Camas Cogeneration Project, Memorandum of Understanding issues and allocation of risks
September 9, 1991	Colorado-Ute Electric Association, PSCo and Tri-State file application for transfer and acquisition of assets before the Colorado Public Utilities Commission
September 26, 1991	PacifiCorp, PSCo and Tri-State file Joint Plan of Reorganization with the United States Bankruptcy Court for the District of Colorado
October 1, 1991	PacifiCorp releases RFP for new generating resources
October 14, 1991	PacifiCorp files application before the Oregon Public Utility Commission for a declaratory ruling regarding Colorado-Ute Acquisition
October 15, 1991	PacifiCorp files application before the Idaho Public Utilities Commission, Washington Utilities and Transportation Commission, and the Public Service Commission of Utah for approvals regarding (1) valuations and (2) accounting in connection with a proposed acquisition of generating resources from Colorado-Ute Electric Association, Inc.
November 25 - 26, 1991	Hearing before the Colorado Public Utilities Commission for transfer and acquisition of Colorado-Ute assets
December 3, 1991	Utah Public Service Commission hearing regarding PacifiCorp application for approvals regarding Colorado-Ute Acquisition

Appendix 6.A
Chronology of Events Related to Resource Acquisitions

Date	Event
December 11, 1991	Public Service Commission of Wyoming holds public hearing on Tri-State's application for authority to issue certain securities regarding Colorado-Ute Acquisition
December 12, 1991	Colorado Public Utilities Commission grants joint application of Colorado-Ute Electric Association, PSCo and Tri-State for transfer and acquisition of assets
December 17, 1991	Wyoming Public Service Commission issues order confirming bench decision authorizing Tri-State to issue certain securities regarding the Colorado-Ute Acquisition
December 19, 1991	PacifiCorp, PSCo and Tri-State file Second Amended Joint Plan of Reorganization with the United States Bankruptcy Court for the District of Colorado
December 23, 1991	PacifiCorp files application with the WUTC and the Public Service Commission of Utah for authority to issue bonds and assume debt in connection with Colorado-Ute Acquisition
December 27, 1991	PacifiCorp files amended petition before the Washington Utilities and Transportation Commission regarding Colorado-Ute Acquisition
January 13, 1992	PacifiCorp files with FERC the Title Page, Notice of Filing, Power and Transmission Services Agreement and Long-Term Power Sales Agreement in connection with Colorado-Ute Acquisition
January 15, 1992	Idaho Public Utilities Commission and WUTC authorizes PacifiCorp to record acquisition costs of the Colorado-Ute Acquisition
January 15, 1992	Utah Public Service Commission issues order regarding Colorado-Ute Acquisition
January 17, 1992	FERC issues Notice of Filing by PacifiCorp regarding Colorado-Ute Acquisition

Appendix 6.A
Chronology of Events Related to Resource Acquisitions

Date	Event
January 24, 1992	Utah Public Service Commission issues order regarding application to issue bonds and assume debt in connection with the Colorado-Ute Acquisition
January 29, 1992	Oregon Public Utility Commission approves PacifiCorp's application for declaratory ruling to allow plant in service at a cost above book value
February 12, 1992	WUTC grants PacifiCorp's application to issue bonds and assume debt in connection with the Colorado-Ute Acquisition
February 19, 1992	United States Bankruptcy Court for the District of Colorado confirms Joint Plan
February 28, 1992	PacifiCorp RFP: Bids are due from participants
March 3, 1992	Asset Purchase Agreement by and among Tri-State, PSCo, PacifiCorp, Colorado-Ute Electric Association and Victor Palmieri as Trustee
March 9, 1992	PacifiCorp, PSCo, Tri-State, Platte River Power Authority and Salt River Project Agricultural Improvement and Power District execute Yampa Project Amended and Restated Participation Agreement
March 12, 1992	PacifiCorp letter to James River addresses points necessary for PacifiCorp to fund the P-2 Scope and Estimate by Harris Group regarding Camas Steam Turbine Generator project
March 30, 1992	PacifiCorp and PSCo execute Long-Term Power Sales Agreement
March 30, 1992	Phase I of PacifiCorp RFP: Resources that meet minimum resource requirements are selected
April 1, 1992	Joint Plan to acquire assets of Colorado-Ute Electric Association becomes effective
April 6, 1992	Tri-State, PSCo and PacifiCorp execute Agreement re Territorial Matters

Appendix 6.A
Chronology of Events Related to Resource Acquisitions

Date	Event
April 9, 1992	Funding and Disbursement Agreement by and among PSCo, Tri-State, PacifiCorp, Western Fuels, Victor Palmieri as Trustee, National Rural Utilities Cooperative Finance Corporation, Colowyo Coal Company, and United Bank of Denver National Association becomes effective
April 15, 1992	PSCo, PacifiCorp and Salt River Project Agricultural Improvement and Power District execute Amended and Restated Hayden Plant Participation Agreement
April 15, 1992	Tri-State and PSCo execute Nucla Station Power Purchase Agreement
April 28, 1992	Phase II of PacifiCorp RFP: Resources that meet general evaluation criteria are selected
May 29, 1992	Camas Steam Turbine Generator General Project Overview, P-2 Scope prepared by Harris Group
June 1, 1992	RAMPP-2 "Balanced Planning for Growth" is completed.
June 1, 1992	PacifiCorp and APS enter into Turbine Development Agreement to construct 150 MW of combustion turbine capacity to be owned by PacifiCorp and constructed by APS
June 11, 1992	PacifiCorp RFP: Final winners are selected
June 15, 1992	Presentation to PacifiCorp Management Council regarding Camas Cogeneration Project
July 1, 1992	PacifiCorp RFP: Contract negotiations commence with winners
July 22, 1992	Presentation to Pacific Power Board regarding James River Camas Cogeneration Project
August 3 - 6, 1992	Maximum capability evaluation is conducted on Cholla Unit 4. Conclusion is reached that Cholla Unit 4 can generate about 390 MW output

Appendix 6.A
Chronology of Events Related to Resource Acquisitions

Date	Event
August 14, 1992	PacifiCorp holds in-house review meeting to discuss project development status, ongoing activities regarding financial and environmental review, among other topics (James River Cogeneration Project)
August 14, 1992	Environmental Services Department due diligence report for James River Camas Plant transmitted to Tom Ramisch from Terry Lumapas
August 18, 1992	Draft Notice of Construction Air Permit Application for the Steam Generator project by James River Corporation
October 6, 1992	Northwest Pipeline Corporation announces possible further expansion of its transmission system (James River Cogeneration Project)
October 8, 1992	PacifiCorp and James River Corporation enter into letter agreement for the development of the Camas Cogeneration Project
November 24, 1992	Arizona Department of Environmental Quality approves 390MW rating for Cholla Unit 4
December 31, 1992	Harris Group completes Scope and Estimate for Camas Cogeneration Project steam turbine generator
Late 1992	Weyerhaeuser Company, Mission Energy Company and Cowlitz County PUD contact PacifiCorp to see if PacifiCorp has an interest in purchasing the output of a cogeneration project (the Cowlitz Cogeneration Project, sometimes referred to as the Longview Project) proposed by Weyerhaeuser and Mission to be constructed at Weyerhaeuser's Longview, Washington paper mill
January 13, 1993	PacifiCorp and James River execute Transmission Facilities Purchase, Easement and License Agreement

Appendix 6.A
Chronology of Events Related to Resource Acquisitions

Date	Event
January 13, 1993	PacifiCorp and James River enter into Camas Development, Construction, Operation and Steam Supply Agreement, a twenty year agreement for the development and operation of Camas Cogeneration Project
February 12, 1993	U.S. Generating Company contacts PacifiCorp to see if PacifiCorp has an interest in purchasing the output of a cogeneration project (the Hermiston Generating Project) proposed by U.S. Generating to be constructed near the Lamb-Weston potato processing plant at Hermiston, Oregon
March 1, 1993	Resource Management International, Inc. completes evaluation of PacifiCorp's Acquisitions of Facilities from Arizona Public Service Company and Colorado-Ute Electric Association
March 1, 1993	PacifiCorp receives unsolicited proposal from Mission Energy Company and Weyerhauser Company proposed Cowlitz Cogeneration Project
April 1, 1993	Board of Director presentation entitled "An Overview of PacifiCorp's Power Supply," which analyzed potential new resource additions, including the Hermiston project
April 1, 1993	PacifiCorp and APS execute Combustion Turbines Construction Agreement for construction of two 75 MW simple cycle combustion turbines
April 1, 1993	James River Cogeneration Project Summary progress report - project proceeding on schedule and within authorized $51,000,000 budget
April 1, 1993	PacifiCorp Board receives Overview of PacifiCorp's Power Supply and evaluation of RAMPP-2 recommendations

Appendix 6.A
Chronology of Events Related to Resource Acquisitions

Date	Event
April 5, 1993	PacifiCorp, Weyerhaeuser, Mission Energy and Cowlitz PUD sign the Cowlitz Project Agreement under which PacifiCorp would purchase the output of the project contingent upon certain conditions, e.g., successful negotiation of a power sale agreement and Board of Directors approval
May 6, 1993	U.S. Generating Company provides PacifiCorp a formal proposal for the purchase of the output from the Hermiston Generating Project
August 1, 1993	PacifiCorp forecasts capacity deficit in 1995 and 1996 summer and winter seasons; recognizes that change in the makeup of its resource portfolio is needed, including an increase in level of gas-fired resources
August 11, 1993	PacifiCorp and Hermiston Generating Company execute the Hermiston Project Memorandum of Understanding under which PacifiCorp would purchase the output of the project contingent upon certain conditions, e.g., successful negotiation of a power sale agreement and Board of Directors approval
August 18, 1993	PacifiCorp's Board of Directors authorizes the acquisition of power from both the Cowlitz Cogeneration Project and the Hermiston Generating Project contingent upon the successful negotiation of definitive project agreements and subsequent Board approval
Fall 1993	Intensive discussions between PacifiCorp and the Cowlitz Cogeneration Project sponsors wind down due to the inability to negotiate a power sale agreement under the terms of the April 5, 1993 agreement satisfactory to all parties. Discussions continued on a less frequent basis but eventually ended without an agreement
September 10, 1993	PacifiCorp discusses with the Regional Advisory Group new power supply opportunities, including Hermiston and Cowlitz
September 30, 1993	PacifiCorp and APS execute letter agreements regarding transmission for Cholla Unit 4 upgrade

Appendix 6.A
Chronology of Events Related to Resource Acquisitions

Date	Event
October 1, 1993	PacifiCorp and APS execute Amendment No. 1 to Transmission Agreement
October 7, 1993	PacifiCorp and Hermiston Generating Company execute the Long-Term Power Sale Agreement (PSA) under which PacifiCorp will purchase 100% of the output for a twenty year term with an option for an additional ten year term. The parties also executed the Option Agreement which gave PacifiCorp the option to acquire a 50 percent undivided interest in the project
November 17, 1993	PacifiCorp's Board of Directors approve the agreements executed on October 7, 1993 regarding PacifiCorp's acquisition of the output from the Hermiston Generating Project
January 7, 1994	Wind Energy Resource Assessment of the Wyoming Wind Project is conducted for PacifiCorp
February 7, 1994	Technical evaluation of proposed turbines for Wyoming Wind Project is completed by W.A. Vachon & Associates, Inc. for PacifiCorp
March 2, 1994	PacifiCorp and APS execute Reciprocal Transmission Service Agreement for 30 MW of transmission service from Cholla to Four Corners for the delivery of increased Cholla Unit 4 output
March 7, 1994	EWEB, PacifiCorp and Toyowest Wyoming, L.L.C execute Development Agreement and Operations and Maintenance Agreement
March 21, 1994	Second Amendment to Cholla Unit 4 Operating Agreement
April 1, 1994	RAMPP-3 "Positioning for Competition and Uncertainty" is completed. Action plan includes gaining experience with renewables such as the Wyoming Wind Project
April 14, 1994	RAMPP-3 submitted to state utility commissions
May 1, 1994	PacifiCorp determines that gas contracts satisfy the requirements of Section 15.4 of the PSA

Appendix 6.A
Chronology of Events Related to Resource Acquisitions

Date	Event
July 1, 1994	PacifiCorp initiates a formal evaluation of the economics of exercising its option to acquire a 50% undivided interest in the Hermiston project
August 22, 1994	EWEB and PacifiCorp enter into Letter of Agreement for generation control and storage subject to FERC approval
August 31, 1994	EWEB and PacifiCorp execute Second Amended and Restated Ownership Agreement
September 7, 1994	Applied Power Concepts, Inc. delivers design specifications and windplant design certificate, noting that specifications are consistent with an expected 30-year useful life span (Wyoming Wind Project)
November 21, 1994	Financial closing for Hermiston Generating Company; Section 15.3 of PSA becomes effective
December 21, 1994	PacifiCorp notifies Hermiston Generating Company that it will exercise its option to acquire a 50% interest in the project as of the contract operation date
December 22, 1994	Geotechnical Engineering report for the Wyoming Wind Project is completed
December 30, 1994	PacifiCorp and Hermiston Generating Company execute the Hermiston Project Purchase Agreement
December 31, 1994	Sensitivity Study regarding wind turbine maintenance costs is completed (Wyoming Wind Project)
January 1, 1995	Bureau of Land Management issues draft environmental impact statement for the Wyoming Wind Project
January 1, 1995	The State of Wyoming issues easements for the Wyoming Wind Project
March 6, 1995	PacifiCorp and APS execute letter agreement related to deferral of in-service date for the PacifiCorp combustion turbines and the payment by PacifiCorp of the management fee to APS

Appendix 6.A
Chronology of Events Related to Resource Acquisitions

Date	Event
March 7, 1995	PacifiCorp and APS execute letter agreement related to wheeling services for PacifiCorp's combustion turbine
April 5, 1995	PacifiCorp and APS execute Restated Transmission Agreement
April 5, 1995	PacifiCorp and APS execute Amendment No. 1 to the Long-Term Power Transaction Agreement and Asset Purchase and Power Exchange Agreement
April 20, 1995	Wind Resource Assessment of Wyoming Wind Project is updated
May 5, 1995	PacifiCorp, APS and Western Area Power Administration execute Transmission Service Agreement for WAPA to provide up to 250 MW of long term, firm transmission service between Glen Canyon and Pinnacle Peak
May 16, 1995	PacifiCorp's Board of Directors approve the purchase agreement exercising the option to acquire a 50% interest in the Hermiston project
August 1, 1995	Bureau of Land Management issues final environmental impact statement for the Wyoming Wind Project
October 2, 1995	Bureau of Land Management receives comments on the final EIS until this date
November 1, 1995	RAMPP-4 "Flexible Choices for a Changing Market" is completed.
November 1, 1995	Third Amendment to Cholla Unit 4 Operating Agreement
December 13, 1995	PacifiCorp and APS execute Amendment No. 3 to the Cholla Unit 4 Operating Agreement to change the method for allocating administrative and general Fossil Generation Administration
December 1995	James River Cogeneration Project goes on line
March 4, 1996	Wind Energy Resource Assessment for Wyoming Wind Project is updated

Appendix 6.A
Chronology of Events Related to Resource Acquisitions

Date	Event
April 15, 1996	APS gives notice to PacifiCorp of its intent to increase firm capacity purchase by 205 MW by summer season 1999 and to convert 205 MW to exchange capacity
May - December 1996	Kenetech files Chapter 11 bankruptcy; SeaWest purchases assets of proposed Wyoming Wind Project
July 1, 1996	Hermiston commercial operation date
Fall 1996	Contract negotiations between SeaWest and PacifiCorp regarding Wyoming Wind Project are held
December 1, 1996	RAMPP-4 Update "1997 IRP Report" is issued
February 20, 1997	Mitsubishi extends warranty on turbines from 3 to 7 years (Wyoming Wind Project)
February 28, 1997	Applied Power Concepts, Inc. reviews Mitsubishi turbines for PacifiCorp
April - July 1997	PacifiCorp works on project and development rights and pre-construction planning and engineering for Wyoming Wind Project
June 3, 1997	PacifiCorp announces invitation for bid on the Wyoming Wind Project
July 10, 1997	Pre-bid meeting is held
July 14, 1997	PacifiCorp tenders contract to S.E., Inc. for Wyoming Wind Project for the Miners to Foote Creek 230 KV transmission line
July 21, 1997	PacifiCorp and Eugene Water & Electric Board and Bonneville Power Administration (BPA) execute Power Purchase Agreement for the Wyoming Wind Project
July 22, 1997	BPA issues Record of Decision for the Wyoming Wind Project Power Purchase Agreement

Appendix 6.A
Chronology of Events Related to Resource Acquisitions

Date	Event
August – September 1997	PacifiCorp obtains bids and selects contractors for Wyoming Wind Project
Fall 1997	Construction on the Wyoming Wind Project commences
September 26, 1997	Groundbreaking ceremony for Wyoming Wind Project
October 1, 1997	SeaWest prepares Plan of Development for the Wyoming Wind Project
December 1, 1997	RAMPP-5 "PacifiCorp Resource and Market Planning Program" is completed
December 23, 1997	FERC Electric Tariff (First Revised Vol. No. 12 of PacifiCorp) is issued
January 1, 1998	FERC Electric Tariff (First Revised Vol. No. 12 of PacifiCorp) becomes effective
January 5, 1998	PacifiCorp issues Project Plan Document for the Wyoming Wind Project, which includes scope of work and construction plan
February 4, 1998	Wind Adjusted Output Test for Wyoming Wind (Foote Creek) Project
May 22, 1998	Final report by Western EcoSystems Technology, Inc. on wildlife monitoring studies for the Wyoming Wind Project
May 28, 1998	Wind Adjusted Output Test for Wyoming Wind (Foote Creek) Project
August 17, 1998	Report on Anemometry Installations to Support the Wind Adjusted Output Test at the Foote Creek Rim Wind Farm
September 3, 1998	Bonneville Power Administration requests to purchase additional output of Wyoming Wind Project

Appendix 6.A
Chronology of Events Related to Resource Acquisitions

Date	Event
September 11, 1998	SeaWest provides final construction report to Applied Power Concepts, Inc.
September 30, 1998	Final carcass search protocol is completed by Western EcoSystems Technology, Inc. (Wyoming Wind Project)
October 12, 1998	Eugene Water & Electric Board and PacifiCorp execute the Generation Control, Storage and Firm Power Supply Agreement for the Wyoming Wind Project
October 15, 1998	PacifiCorp files with FERC the Power Purchase Agreement between BPA and PacifiCorp and unexecuted Generation Control, Storage and Firm Power Supply Agreement between EWEB and PacifiCorp, in order to provide for generation services needed to permit Bonneville and EWEB to participate in the Wyoming Wind Project
December 3, 1998	Applied Power Concepts, Inc. submits preliminary review of MH1 test data (Wyoming Wind Project)
December 8, 1998	FERC accepts filing of PacifiCorp's tariff regarding the Power Purchase Agreement with BPA and the Generation Control, Storage and Firm Power Supply Agreement between EWEB and PacifiCorp
December 16, 1998	Application to assign right of way grant for Foote Creek Rim Wind Energy Project from ToyoWest Wyoming, LLC to PacifiCorp, Eugene Water & Electric Board and SeaWest Energy Land Associates, LLC
January 20, 1999	SeaWest Energy Corporation receives decision that the US Department of the Interior approved the application to assign the right of way for Foote Creek Rim Wind Energy Project from ToyoWest Wyoming, LLC to PacifiCorp, Eugene Water & Electric Board and SeaWest Energy Land Associates, LLC

Appendix 6.A
Chronology of Events Related to Resource Acquisitions

Date	Event
March 29, 1999	Service agreement for long term firm transmission service on direct assignment facilities between PacifiCorp Transmission Function and PacifiCorp Merchant Function is executed
April 20, 1999	Applied Power Concepts, Inc. conducts final construction audit for Wyoming Wind Project
April 20, 1999	PacifiCorp Transmission Function and PacifiCorp Merchant Function execute Generation Interconnection Agreement
April 21, 1999	Wind Energy Subleases between SeaWest Energy Land Associates, LLC and Eugene Water Electric Board and PacifiCorp
April 22, 1999	Title of the Wyoming Wind Project is formally transferred to PacifiCorp and EWEB; wind turbines numbered 1-69 go on-line; project is completed and commercial operation begins
June 1, 1999	Wyoming Wind (Foote Creek) projects II and III begin delivering energy to BPA and PSCO
August 11, 1999	PacifiCorp and APS execute letter agreement concerning purchase power and delivery of exchange obligations
December 31, 1999	RAMPP-6 "Interim Report" is completed.

Appendix 6.B.1

Appendix 6.B.1
Historical Energy Sales (Gwh) By Class

STATE	YEAR	RES	COM	IND	PSL	OSP	INT	IRR	Total
OR	1980	4,371	2,670	3,254	36	1	11	302	10,644
	1981	4,276	2,761	3,156	35	1	10	306	10,545
	1982	4,413	2,827	2,971	34	2	11	200	10,456
	1983	4,158	2,685	3,246	32	2	9	240	10,372
	1984	4,160	2,743	3,408	31	0	8	251	10,601
	1985	4,205	2,849	3,478	31	0	2	264	10,830
	1986	3,950	2,860	3,574	31	0	13	259	10,687
	1987	4,006	2,978	3,751	32	0	13	278	11,057
	1988	4,169	3,059	3,861	31	0	12	253	11,384
	1989	4,360	3,181	3,881	31	0	13	271	11,738
	1990	4,479	3,303	3,867	31	0	13	285	11,978
	1991	4,561	3,375	3,819	31	0	14	299	12,099
	1992	4,460	3,456	3,870	31	0	14	326	12,156
	1993	4,849	3,566	4,042	33	0	11	261	12,762
	1994	4,789	3,664	4,303	32	0	13	335	13,137
	1995	4,758	3,795	4,216	31	0	0	288	13,088
	1996	4,978	3,916	4,000	35	0	0	358	13,288
	1997	4,963	4,030	4,202	36	0	15	335	13,581
	1998	5,142	4,210	4,649	44	0	0	257	14,303
	1999	5,087	4,237	3,997	41	0	0	331	13,694
	2000	5,182	4,420	4,061	42	0	0	351	14,055
WA	1980	1,312	738	533	10	0	0	142	2,735
	1981	1,246	758	563	10	0	0	151	2,727
	1982	1,332	791	552	10	0	0	140	2,825
	1983	1,237	789	609	9	0	0	129	2,771
	1984	1,332	813	668	7	0	0	130	2,950
	1985	1,370	842	698	7	0	0	148	3,065
	1986	1,259	841	723	7	0	0	132	2,961
	1987	1,238	895	734	7	0	0	139	3,014
	1988	1,255	923	748	7	0	0	138	3,072
	1989	1,296	964	777	7	0	0	133	3,179
	1990	1,315	989	799	8	0	0	146	3,256
	1991	1,361	1,007	834	7	0	0	145	3,354
	1992	1,362	1,057	932	8	0	0	160	3,518
	1993	1,484	1,101	929	8	0	0	141	3,662
	1994	1,418	1,157	958	8	0	0	177	3,717
	1995	1,429	1,148	978	8	0	0	129	3,692
	1996	1,504	1,194	977	8	0	0	144	3,828
	1997	1,524	1,237	1,045	9	0	0	141	3,956

Appendix 6.B.1
Historical Energy Sales (Gwh) By Class

STATE	YEAR	RES	COM	IND	PSL	OSP	INT	IRR	Total
	1998	1,469	1,321	1,082	9	0	0	157	4,038
	1999	1,431	1,333	1,063	9	0	0	162	3,998
	2000	1,478	1,356	1,064	9	0	0	152	4,059
MT	1980	258	138	139	3	0	0	1	541
	1981	252	142	137	3	0	0	1	535
	1982	260	155	131	3	0	1	2	551
	1983	247	155	159	3	0	1	0	564
	1984	266	168	160	2	0	1	1	597
	1985	281	180	161	2	0	1	3	628
	1986	255	180	170	2	0	0	2	610
	1987	252	186	168	2	0	0	2	611
	1988	257	193	189	2	0	0	3	643
	1989	281	200	198	2	0	0	2	683
	1990	285	204	204	2	0	0	2	696
	1991	296	213	197	2	0	0	2	710
	1992	294	221	178	2	0	0	2	698
	1993	333	237	188	2	0	0	1	761
	1994	320	244	206	2	0	0	3	775
	1995	335	250	216	2	0	0	2	805
	1996	362	270	276	2	0	0	2	912
	1997	361	271	311	2	0	0	1	946
	1998	257	219	257	2	0	0	2	737
	1999	0	0	0	0	0	0	0	0
	2000	0	0	0	0	0	0	0	0
WY	1980	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1981	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1982	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1983	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1984	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1985	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1986	753	872	4,849	13	0	16	15	6,518
	1987	725	861	5,404	13	0	10	13	7,027
	1988	742	882	5,652	13	0	1	17	7,307
	1989	752	873	6,027	13	0	0	16	7,681
	1990	753	889	6,414	13	0	0	14	8,082
	1991	779	913	6,175	13	0	0	11	7,890
	1992	763	918	6,104	13	0	0	14	7,811
	1993	816	947	6,059	13	0	0	11	7,845
	1994	802	991	5,844	13	0	0	16	7,665

Appendix 6.B.1
Historical Energy Sales (Gwh) By Class

STATE	YEAR	RES	COM	IND	PSL	OSP	INT	IRR	Total
	1995	822	1,010	5,198	13	0	0	11	7,054
	1996	854	1,055	5,187	13	10	0	15	7,133
	1997	856	1,007	5,442	14	60	0	12	7,390
	1998	840	1,002	5,283	13	61	0	14	7,213
	1999	831	1,027	5,313	14	53	0	13	7,250
	2000	862	1,081	5,394	13	63	0	16	7,429
CA	1980	343	164	97	4	0	0	94	702
	1981	337	166	87	3	0	0	103	695
	1982	352	172	69	2	0	0	86	682
	1983	330	167	81	2	0	0	84	665
	1984	322	169	104	3	0	0	95	693
	1985	311	167	98	3	0	0	97	677
	1986	295	164	105	2	0	0	86	653
	1987	303	172	101	2	0	0	82	660
	1988	315	180	107	2	0	0	84	689
	1989	331	191	101	2	0	0	79	705
	1990	336	210	97	2	0	0	83	728
	1991	348	217	86	2	0	0	83	737
	1992	337	218	74	3	0	0	85	717
	1993	363	224	82	3	0	0	75	746
	1994	360	230	81	2	0	0	90	764
	1995	354	229	78	2	0	0	73	737
	1996	346	220	63	2	0	0	32	662
	1997	337	220	54	2	0	0	28	642
	1998	374	246	72	3	0	0	67	762
	1999	367	246	67	2	0	0	97	779
	2000	368	255	67	2	0	0	92	785
UT	1980	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1981	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1982	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1983	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1984	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1985	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1986	3,005	2,832	3,925	47	542	0	86	10,437
	1987	3,009	2,958	4,138	44	550	0	87	10,787
	1988	3,153	3,153	4,796	44	542	0	88	11,776
	1989	3,126	3,160	5,098	42	586	0	117	12,128
	1990	3,207	3,269	5,208	43	527	0	143	12,398
	1991	3,358	3,435	5,353	44	532	0	116	12,839

Appendix 6.B.1
Historical Energy Sales (Gwh) By Class

STATE	YEAR	RES	COM	IND	PSL	OSP	INT	IRR	Total
	1992	3,380	3,596	5,773	45	487	0	147	13,428
	1993	3,528	3,731	5,690	47	483	0	122	13,601
	1994	3,777	4,064	5,887	49	501	0	159	14,438
	1995	3,778	4,143	6,378	51	482	0	114	14,946
	1996	4,138	4,509	6,821	56	511	1	133	16,168
	1997	4,279	4,841	6,809	52	500	11	109	16,602
	1998	4,340	5,034	6,841	58	460	0	111	16,844
	1999	4,747	5,549	6,890	58	469	0	134	17,846
	2000	4,912	6,051	7,149	70	502	0	175	18,859
ID	1980	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1981	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1982	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1983	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1984	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1985	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1986	583	222	1,229	2	0	0	398	2,434
	1987	568	218	1,497	2	0	0	396	2,682
	1988	600	235	1,644	2	0	0	549	3,029
	1989	619	234	1,686	3	0	0	490	3,032
	1990	616	241	1,688	2	0	0	554	3,101
	1991	651	255	1,746	3	0	0	456	3,112
	1992	635	268	1,689	3	0	0	589	3,182
	1993	683	279	1,683	2	0	0	387	3,036
	1994	661	295	1,620	2	0	0	625	3,204
	1995	555	223	1,651	2	0	0	416	2,846
	1996	571	241	1,682	2	0	0	567	3,063
	1997	581	263	1,722	2	0	0	434	3,002
	1998	547	267	1,744	2	0	0	430	2,989
	1999	569	285	1,715	2	0	0	467	3,038
	2000	574	308	1,629	2	0	0	601	3,114

Appendix 6.B.2

Appendix 6.B.2
Historical Average Number of Customers By Class

STATE	YEAR	RES	COM	IND	PSL	OSP	INT	IRR	Total
OR	1980	337,476	47,490	965	267	3	7	3,701	389,909
	1981	342,072	48,723	1,011	290	3	7	3,631	395,737
	1982	342,594	49,323	1,052	314	3	7	3,822	397,115
	1983	345,344	49,729	1,081	327	2	7	3,510	400,000
	1984	338,503	49,042	1,103	319	1	5	3,379	392,352
	1985	339,070	49,686	1,135	330	2	1	3,743	393,967
	1986	340,832	50,446	1,194	332	2	1	3,593	396,400
	1987	342,105	51,058	1,366	338	2	2	3,788	398,659
	1988	345,626	51,795	1,588	339	2	2	3,597	402,949
	1989	350,373	52,413	1,885	349	0	2	3,587	408,609
	1990	355,885	53,361	1,973	352	0	2	3,722	415,295
	1991	361,859	54,183	2,030	356	0	2	3,630	422,060
	1992	367,651	55,530	2,095	364	0	2	3,867	429,509
	1993	373,847	56,592	2,177	365	0	1	3,501	436,483
	1994	381,428	57,729	2,260	362	0	1	3,904	445,684
	1995	389,090	59,328	2,345	367	0	0	3,674	454,804
	1996	384,865	62,636	2,420	511	0	0	5,721	456,153
	1997	396,959	64,637	2,305	548	0	0	9,373	473,822
	1998	402,203	65,220	2,250	562	0	0	8,401	478,636
	1999	408,929	66,127	2,183	580	0	0	8,366	486,185
	2000	415,730	67,524	2,149	602	0	0	8,355	494,360
WA	1980	80,827	10,838	372	105	0	0	2,852	94,994
	1981	81,702	11,083	391	113	0	0	2,928	96,217
	1982	82,217	11,287	408	121	0	0	2,935	96,968
	1983	83,293	11,417	418	119	0	0	2,929	98,176
	1984	84,674	11,630	419	115	0	0	2,907	99,745
	1985	85,636	11,970	380	118	0	0	3,079	101,183
	1986	85,949	12,161	367	119	0	0	2,700	101,296
	1987	86,250	12,252	424	124	0	0	2,698	101,748
	1988	87,038	12,440	488	123	0	0	2,741	102,830
	1989	87,453	12,613	523	121	0	0	2,622	103,332
	1990	88,035	12,786	599	123	0	0	2,781	104,324
	1991	88,827	12,991	643	128	0	0	2,728	105,317
	1992	90,015	13,329	661	139	0	0	2,774	106,918
	1993	91,291	13,612	693	147	0	0	2,593	108,336
	1994	92,866	13,915	734	155	0	0	2,840	110,510
	1995	94,018	14,199	780	166	0	0	2,630	111,793
	1996	93,999	15,052	796	194	0	0	3,462	113,503
	1997	93,360	14,880	738	206	0	0	5,429	114,613

Appendix 6.B.2
Historical Average Number of Customers By Class

STATE	YEAR	RES	COM	IND	PSL	OSP	INT	IRR	Total
	1998	94,430	15,096	722	214	0	0	5,463	115,925
	1999	95,271	15,330	710	227	0	0	5,466	117,004
	2000	96,088	15,637	700	244	0	0	5,431	118,100
MT	1980	20,897	3,564	47	13	0	2	32	24,555
	1981	21,327	3,679	51	16	0	2	31	25,106
	1982	21,672	3,800	55	15	0	2	41	25,585
	1983	22,110	3,970	62	18	0	2	3	26,165
	1984	22,735	4,089	67	19	0	2	37	26,949
	1985	23,252	4,124	69	20	0	2	47	27,514
	1986	23,629	4,281	67	26	0	1	44	28,048
	1987	23,761	4,365	67	32	0	0	46	28,271
	1988	23,924	4,451	89	34	0	0	48	28,546
	1989	24,252	4,473	146	38	0	0	44	28,953
	1990	24,528	4,539	164	43	0	0	43	29,317
	1991	24,871	4,604	166	43	0	0	43	29,727
	1992	25,518	4,696	162	41	0	0	49	30,466
	1993	26,269	4,832	174	42	0	0	36	31,353
	1994	27,065	5,003	179	42	0	0	48	32,337
	1995	27,825	5,172	181	43	0	0	44	33,265
	1996	28,275	5,545	181	49	0	0	81	34,131
	1997	28,200	5,673	170	58	0	0	130	34,231
	1998	28,585	5,808	165	66	0	0	131	34,755
	1999	19,301	3,924	42	43	0	0	88	23,398
	2000	19,301	3,924	42	43	0	0	88	23,398
WY	1980	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1981	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1982	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1983	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1984	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1985	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1986	93,366	17,681	1,883	154	0	3	314	113,401
	1987	91,473	17,675	1,817	143	0	3	324	111,435
	1988	91,387	17,611	1,999	156	0	3	307	111,463
	1989	90,969	17,352	2,382	167	0	0	306	111,176
	1990	90,929	17,420	2,473	160	0	0	317	111,299
	1991	91,306	17,610	2,508	165	0	0	307	111,896
	1992	91,749	17,833	2,525	166	0	0	313	112,586
	1993	92,215	18,092	2,470	170	0	0	307	113,254
	1994	93,181	18,341	2,518	169	0	0	313	114,522

Appendix 6.B.2
Historical Average Number of Customers By Class

STATE	YEAR	RES	COM	IND	PSL	OSP	INT	IRR	Total
	1995	94,206	18,685	2,529	171	0	0	316	115,907
	1996	94,830	19,549	2,545	260	0	0	349	117,533
	1997	94,865	19,355	2,476	320	0	0	491	117,507
	1998	95,754	19,525	2,442	327	0	0	495	118,543
	1999	96,300	19,740	2,378	324	0	0	508	119,250
	2000	97,121	20,147	2,339	319	0	0	520	120,446
CA	1980	25,429	5,224	165	54	0	0	647	31,519
	1981	26,293	5,430	166	50	0	0	784	32,723
	1982	26,819	5,585	164	57	0	0	764	33,389
	1983	27,276	5,617	159	69	0	0	758	33,879
	1984	27,833	5,717	158	75	0	0	815	34,598
	1985	28,080	5,777	159	78	0	0	861	34,955
	1986	28,446	5,834	152	74	0	0	807	35,313
	1987	28,704	5,901	144	78	0	0	810	35,637
	1988	29,147	5,995	152	87	0	0	820	36,201
	1989	29,809	6,122	161	88	0	0	764	36,944
	1990	30,546	6,209	152	76	0	0	809	37,792
	1991	31,054	6,287	153	76	0	0	817	38,387
	1992	31,491	6,198	147	72	0	0	832	38,740
	1993	31,872	6,420	156	75	0	0	793	39,316
	1994	32,184	6,476	160	74	0	0	878	39,772
	1995	32,463	6,470	172	81	0	0	790	39,976
	1996	31,140	6,409	172	103	0	0	545	38,369
	1997	30,173	6,111	154	116	0	0	859	37,413
	1998	32,280	6,939	164	126	0	0	1,765	41,274
	1999	32,435	6,981	154	134	0	0	1,770	41,474
	2000	32,693	7,028	153	138	0	0	1,778	41,790
UT	1980	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1981	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1982	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1983	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1984	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1985	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1986	410,123	38,151	6,839	1,614	48	3	688	457,466
	1987	418,414	39,332	6,313	1,669	47	3	728	466,506
	1988	422,321	40,147	5,727	1,722	46	3	701	470,667
	1989	428,784	41,210	5,807	1,728	48	3	812	478,392
	1990	435,641	41,694	6,611	1,831	48	3	904	486,732
	1991	443,049	42,250	7,671	1,951	42	3	890	495,856

Appendix 6.B.2
Historical Average Number of Customers By Class

STATE	YEAR	RES	COM	IND	PSL	OSP	INT	IRR	Total
	1992	451,387	43,170	8,557	2,144	28	3	983	506,272
	1993	461,575	44,353	9,631	2,373	21	4	955	518,912
	1994	473,668	45,837	10,849	2,528	19	3	1,048	533,952
	1995	487,754	47,314	11,084	2,728	20	3	1,021	549,924
	1996	503,471	49,758	11,939	2,806	25	2	1,144	569,145
	1997	527,642	51,517	8,229	2,828	27	0	1,558	591,801
	1998	546,898	53,444	6,722	2,986	27	0	1,957	612,034
	1999	563,259	56,141	6,390	3,152	28	0	1,998	630,968
	2000	576,776	58,912	6,177	2,766	28	0	2,069	646,728
ID	1980	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1981	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1982	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1983	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1984	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1985	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	1986	41,856	6,026	859	86	0	0	1,110	49,937
	1987	42,088	6,096	837	91	0	0	1,434	50,546
	1988	42,396	6,133	857	91	0	0	1,443	50,920
	1989	42,814	6,119	904	95	0	0	1,546	51,478
	1990	43,273	6,184	992	95	0	0	1,739	52,283
	1991	44,079	6,365	996	108	0	0	1,616	53,164
	1992	44,987	6,533	1,012	108	0	0	1,996	54,636
	1993	46,113	6,701	1,028	106	0	0	1,876	55,824
	1994	47,143	6,916	1,048	106	0	0	2,103	57,316
	1995	41,383	6,134	1,024	105	0	0	1,871	50,517
	1996	40,123	5,574	946	102	0	0	2,051	48,796
	1997	40,891	5,681	932	116	0	0	3,607	51,227
	1998	41,727	5,819	910	122	0	0	4,420	52,998
	1999	42,878	5,996	897	135	0	0	4,420	54,326
	2000	43,887	6,172	883	150	0	0	4,450	55,542

Appendix 6.B.3

Appendix 6.B.3
Forecast Energy Sales (Gwh) By Class

ZONE	YEAR	RES	COM	IND	PSL	OSP	INT	IRR	Total
OR	2001	5,248	4,442	4,077	39	0	0	294	14,099
	2002	5,318	4,523	4,086	40	0	0	292	14,258
	2003	5,391	4,621	4,172	41	0	0	293	14,517
	2004	5,454	4,704	4,266	41	0	0	294	14,759
	2005	5,511	4,777	4,340	42	0	0	295	14,965
	2006	5,563	4,844	4,390	42	0	0	297	15,136
	2007	5,613	4,908	4,453	43	0	0	298	15,315
	2008	5,665	4,973	4,542	44	0	0	301	15,524
	2009	5,718	5,041	4,620	44	0	0	302	15,726
	2010	5,771	5,110	4,673	45	0	0	304	15,903
	2011	5,823	5,181	4,720	46	0	0	306	16,076
	2012	5,962	5,257	4,807	46	0	0	307	16,379
	2013	6,110	5,342	4,915	46	0	0	308	16,722
	2014	6,269	5,440	5,049	46	0	0	310	17,114
	2015	6,444	5,545	5,207	47	0	0	311	17,554
	2016	6,627	5,652	5,359	47	0	0	312	17,997
	2017	6,826	5,771	5,517	47	0	0	313	18,474
	2018	7,031	5,889	5,664	47	0	0	315	18,945
	2019	7,136	6,030	5,766	48	0	0	316	19,295
	2020	7,243	6,174	5,869	48	0	0	317	19,651
WA	2001	1,465	1,360	1,040	9	0	0	147	4,021
	2002	1,477	1,390	1,039	10	0	0	147	4,063
	2003	1,492	1,414	1,059	10	0	0	148	4,124
	2004	1,511	1,435	1,080	10	0	0	148	4,186
	2005	1,532	1,456	1,102	11	0	0	149	4,250
	2006	1,554	1,476	1,124	11	0	0	150	4,315
	2007	1,575	1,497	1,146	11	0	0	151	4,380
	2008	1,597	1,517	1,164	12	0	0	152	4,443
	2009	1,620	1,538	1,185	12	0	0	154	4,509
	2010	1,643	1,560	1,208	12	0	0	155	4,578
	2011	1,666	1,582	1,233	13	0	0	156	4,649
	2012	1,712	1,604	1,250	13	0	0	157	4,736
	2013	1,762	1,627	1,266	13	0	0	158	4,825
	2014	1,811	1,652	1,290	13	0	0	159	4,924
	2015	1,867	1,679	1,312	13	0	0	159	5,030
	2016	1,922	1,706	1,334	13	0	0	159	5,134
	2017	1,982	1,734	1,361	13	0	0	160	5,250
	2018	2,041	1,761	1,388	13	0	0	160	5,364
	2019	2,073	1,806	1,432	13	0	0	160	5,485
	2020	2,105	1,853	1,478	13	0	0	160	5,609

Appendix 6.B.3
Forecast Energy Sales (Gwh) By Class

ZONE	YEAR	RES	COM	IND	PSL	OSP	INT	IRR	Total
WY	2001	850	1,073	5,181	13	58	0	13	8,252
	2002	861	1,102	5,133	13	58	0	12	8,156
	2003	869	1,118	5,187	13	58	0	12	8,223
	2004	877	1,129	5,268	14	58	0	12	8,327
	2005	886	1,140	5,346	14	58	0	13	8,428
	2006	894	1,150	5,418	14	58	0	13	8,520
	2007	902	1,161	5,486	14	58	0	13	8,608
	2008	911	1,171	5,558	14	58	0	13	8,700
	2009	919	1,182	5,633	14	58	0	13	8,795
	2010	928	1,193	5,707	14	58	0	13	8,890
	2011	943	1,222	5,781	15	58	0	13	9,011
	2012	954	1,233	5,889	15	58	0	13	9,156
	2013	965	1,245	5,997	15	58	0	13	9,298
	2014	976	1,256	6,062	15	58	0	13	9,397
	2015	988	1,268	6,139	15	58	0	13	9,511
	2016	1,000	1,280	6,213	15	58	0	13	9,610
	2017	1,012	1,292	6,294	15	58	0	13	9,724
	2018	1,025	1,304	6,385	15	58	0	13	9,850
	2019	1,036	1,332	6,488	15	58	0	13	9,993
	2020	1,047	1,361	6,187	16	58	0	13	9,327
CA	2001	365	250	69	3	0	0	84	770
	2002	370	251	70	3	0	0	83	777
	2003	378	258	70	3	0	0	80	788
	2004	386	265	71	3	0	0	81	807
	2005	395	272	72	3	0	0	83	824
	2006	403	279	72	3	0	0	84	842
	2007	412	287	73	3	0	0	86	860
	2008	420	294	73	3	0	0	87	877
	2009	429	302	74	3	0	0	89	896
	2010	438	310	74	3	0	0	90	916
	2011	443	312	75	3	0	0	91	924
	2012	449	317	75	3	0	0	91	936
	2013	456	321	76	3	0	0	92	947
	2014	463	324	76	3	0	0	92	958
	2015	470	328	77	3	0	0	93	970
	2016	477	327	77	3	0	0	93	977
	2017	484	329	78	3	0	0	93	987
	2018	491	331	78	3	0	0	94	997
	2019	496	334	78	3	0	0	94	1,006
	2020	501	337	79	3	0	0	94	1,015
UT	2001	4,814	6,387	7,067	54	475	0	120	18,917

Appendix 6.B.3
Forecast Energy Sales (Gwh) By Class

ZONE	YEAR	RES	COM	IND	PSL	OSP	INT	IRR	Total
	2002	4,895	6,203	7,177	52	478	0	121	18,927
	2003	5,016	6,246	7,477	53	485	0	122	19,398
	2004	5,144	6,438	7,745	54	492	0	122	19,994
	2005	5,265	6,626	7,996	54	499	0	122	20,562
	2006	5,362	6,813	8,253	55	506	0	122	21,111
	2007	5,459	7,010	8,512	56	514	0	122	21,672
	2008	5,553	7,212	8,788	57	521	0	122	22,253
	2009	5,655	7,419	9,071	58	528	0	122	22,853
	2010	5,754	7,628	9,364	59	536	0	122	23,463
	2011	5,852	7,843	9,666	60	544	0	122	24,087
	2012	6,082	8,051	9,871	60	551	0	123	24,737
	2013	6,314	8,254	10,044	61	558	0	123	25,354
	2014	6,542	8,447	10,284	62	564	0	123	26,023
	2015	6,781	8,633	10,469	63	569	0	123	26,639
	2016	7,027	8,815	10,681	64	576	0	123	27,286
	2017	7,244	8,960	11,010	65	581	0	123	27,983
	2018	7,539	9,163	11,366	66	588	0	123	28,845
	2019	7,766	9,527	11,813	67	595	0	124	29,892
	2020	7,999	9,906	12,277	68	602	0	125	30,977
ID	2001	590	296	1,723	2	0	0	505	3,117
	2002	616	304	1,732	2	0	0	503	3,157
	2003	626	312	1,735	2	0	0	506	3,181
	2004	634	318	1,739	2	0	0	508	3,202
	2005	644	325	1,742	2	0	0	511	3,224
	2006	654	332	1,746	2	0	0	513	3,247
	2007	664	338	1,749	2	0	0	516	3,270
	2008	674	345	1,753	2	0	0	518	3,293
	2009	685	352	1,756	2	0	0	521	3,316
	2010	696	359	1,760	2	0	0	524	3,341
	2011	707	367	1,763	2	0	0	526	3,365
	2012	729	373	1,767	2	0	0	529	3,400
	2013	753	380	1,770	2	0	0	532	3,437
	2014	779	387	1,774	2	0	0	534	3,476
	2015	806	394	1,777	2	0	0	537	3,517
	2016	834	401	1,781	2	0	0	540	3,558
	2017	873	407	1,785	2	0	0	542	3,609
	2018	901	413	1,788	2	0	0	545	3,649
	2019	917	425	1,792	2	0	0	547	3,682
	2020	933	436	1,795	2	0	0	549	3,716

Appendix 6.B.4

Appendix 6.B.4
Forecast Average Number of Customers by Class

STATE	RES	COM	IND	PSL	OSP	INT	IRR	Total
OR	422,331	69,030	2,197	0	0	0	8,318	501,876
	429,360	70,553	2,250	0	0	0	8,310	510,473
	435,197	72,081	2,308	0	0	0	8,333	517,919
	440,310	73,374	2,360	0	0	0	8,366	524,410
	444,846	74,513	2,401	0	0	0	8,399	530,159
	448,983	75,566	2,429	0	0	0	8,442	535,420
	453,068	76,557	2,463	0	0	0	8,493	540,581
	457,259	77,568	2,513	0	0	0	8,552	545,892
	461,546	78,628	2,556	0	0	0	8,605	551,335
	465,781	79,714	2,586	0	0	0	8,653	556,734
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
WA	96,835	15,916	703	0	0	0	5,431	118,885
	97,738	16,271	707	0	0	0	5,437	120,153
	98,789	16,552	719	0	0	0	5,459	121,519
	100,047	16,800	733	0	0	0	5,486	123,066
	101,426	17,040	747	0	0	0	5,513	124,726
	102,853	17,280	762	0	0	0	5,553	126,448
	104,249	17,516	777	0	0	0	5,595	128,137
	105,748	17,757	789	0	0	0	5,636	129,930
	107,255	18,003	804	0	0	0	5,675	131,737
	108,767	18,256	819	0	0	0	5,719	133,561
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
WY	98,009	20,573	2,362	0	0	0	532	121,476

Appendix 6.B.4
Forecast Average Number of Customers by Class

	98,936	21,126	2,369	0	0	0	529	122,960
	99,866	21,429	2,404	0	0	0	529	124,228
	100,821	21,640	2,440	0	0	0	531	125,432
	101,781	21,842	2,475	0	0	0	534	126,632
	102,733	22,041	2,505	0	0	0	536	127,815
	103,673	22,240	2,535	0	0	0	538	128,986
	104,647	22,440	2,567	0	0	0	540	130,194
	105,631	22,644	2,599	0	0	0	542	131,416
	106,614	22,851	2,631	0	0	0	544	132,640
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CA	33,013	7,053	178	0	0	0	1,771	42,015
	33,356	7,077	209	0	0	0	1,746	42,388
	34,079	7,257	213	0	0	0	1,693	43,242
	34,851	7,467	215	0	0	0	1,700	44,233
	35,599	7,669	216	0	0	0	1,731	45,215
	36,351	7,873	218	0	0	0	1,762	46,204
	37,116	8,077	220	0	0	0	1,794	47,207
	37,873	8,284	222	0	0	0	1,825	48,204
	38,687	8,500	223	0	0	0	1,858	49,268
	39,511	8,724	225	0	0	0	1,892	50,352
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
UT	588,597	61,398	6,228	0	7	0	2,060	658,290
	599,749	64,357	6,424	0	0	0	2,072	672,602
	614,555	66,555	6,707	0	0	0	2,079	689,896

Appendix 6.B.4
Forecast Average Number of Customers by Class

	630,222	68,597	6,948	0	0	0	2,081	707,848
	645,028	70,603	7,172	0	0	0	2,083	724,886
	657,000	72,599	7,403	0	0	0	2,085	739,087
	668,827	74,699	7,635	0	0	0	2,087	753,248
	680,363	76,852	7,883	0	0	0	2,089	767,187
	692,832	79,058	8,137	0	0	0	2,091	782,118
	704,972	81,291	8,399	0	0	0	2,093	796,755
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
ID	44,744	6,349	895	0	0	0	4,430	56,418
	45,693	6,508	901	0	0	0	4,417	57,519
	46,388	6,663	905	0	0	0	4,430	58,386
	47,044	6,806	907	0	0	0	4,452	59,209
	47,746	6,948	909	0	0	0	4,474	60,077
	48,485	7,094	911	0	0	0	4,497	60,987
	49,230	7,232	913	0	0	0	4,519	61,894
	50,017	7,372	915	0	0	0	4,542	62,846
	50,804	7,519	917	0	0	0	4,565	63,805
	51,597	7,675	919	0	0	0	4,588	64,779
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a