STRATEGY FOR UTILITY CUSTOMER LOAD REDUCTION UNDER SUBSCRIPTION POWER SALES CONTRACTS AND UTILITY CUSTOMER EXPORTS OF UNPLANNED RESOURCES UNDER SECTION 9(c) OF THE NORTHWEST POWER ACT

ADMINISTRATOR'S RECORD OF DECISION

JUNE 2001

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I. INTRODUCTION

Regional customers of the Bonneville Power Administrator (BPA) have been requested to voluntarily reduce the amount of load they have placed on BPA under their individual Subscription power sale contracts in an effort to reduce an expected dramatic rate increase in the BPA's wholesale power rates that become effective on October 1, 2001. This Utility Customer Load Reduction Strategy (Strategy) allows for an offer of contract amendment to facilitate load reductions under the pre-Subscription and Subscription power sale contracts between public body, cooperative, and federal agency[1] customers (collectively referred as "preference customers") and BPA. In reducing a portion of their BPA served loads, BPA expects some of its preference customers, as well as investor-owned utility (IOU) customers, to add unplanned resources to temporarily meet such load obligations. Therefore, this Strategy also includes a determination under section 9(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) regarding possible future exports by preference customers and IOUs of their unplanned resources.

II. BACKGROUND

BPA was created in 1937 to market electric power generated at Bonneville Dam, and to construct and operate facilities for the transmission of power. 16 U.S.C. § 832-832l (1994 & Supp. III 1997). Since that time, Congress has directed BPA to market power generated at additional facilities. *Id*. § 838f. Currently, BPA markets power generated at 30 Federal hydroelectric projects and several non-Federal projects. BPA also owns and operates approximately 80 percent of the Pacific Northwest's high-voltage transmission system. In 1974, BPA became a self-financed agency that no longer receives annual appropriations. *Id*. § 838i. BPA's rates must therefore produce sufficient revenues to repay all Federal investments in the power and transmission systems, and to carry out BPA's additional statutory objectives. *See id*. §§ 832f, 838g, 838i, and 839e(a).

[1] Federal agencies are not preference customers of BPA, but BPA dispenses with its power obligation to this group of customers under the same rate as used for its sales of federal power to qualified public body and cooperative customers.

A. BPA's Power Subscription Strategy

The concept of power subscription came from the Comprehensive Review of the Northwest energy system, convened by the governors of Idaho, Montana, Oregon, and Washington to assist the Northwest through the transition to competitive electricity markets. The goal of the review was to develop recommendations for changes in the region's electric utility industry through an open public process involving a broad cross-section of regional interests. In December 1996, after over a year of intense study, the Comprehensive Review Steering Committee released its Final Report. The Final Report recommended that BPA capture and deliver the low-cost benefits of the Federal hydropower system to Northwest energy customers through a subscription-based power sales approach. In early 1997, the governors' representatives formed a Transition Board to monitor, guide, and evaluate progress on these recommendations.

An important element of the Final Report was the formation of a Subscription Work Group. The Work Group, which generally met in Portland twice a month from March 1997 through September 1998, was open to the public. On average, 40-45 participants--representing customers, customer associations, Tribes, state governments, public interest groups, and BPA--attended. Three subgroups formed to more intensely pursue the resolution of issues involving business relationships, products and services, and implementation. BPA, its customers, and other interested parties discussed and clarified many Subscription issues. During this time, BPA and the public confirmed goals, defined issues, developed an implementation process for offering Subscription, and developed proposed product and pricing principles.

During the spring and summer of 1998, BPA conducted extensive public meetings with all interested parties regarding the development of BPA's Power Subscription Strategy. BPA developed the Power Subscription Strategy Proposal after considering the efforts of the Subscription Work Group. On September 18, 1998, BPA released its Power Subscription Strategy Proposal for public comment. Accompanying the proposal was a press release entitled "Spreading Federal Power Benefits" and a Keeping Current publication entitled "Getting Power to the People of the Northwest, BPA's Power Subscription Proposal for the 21st Century." Keeping Current (Sept. 1998). During the comment period BPA received nearly 200 responses to the proposal comprising nearly 600 pages of comments. After review and analysis of these comments, BPA published its final Power Subscription Strategy on December 21, 1998. See Power Subscription Strategy, and Power Subscription Strategy, Administrator's Record of Decision (Strategy ROD). At the same time, the Administrator published a National Environmental Policy Act (NEPA) ROD that contained an environmental analysis of the Power Subscription Strategy. This NEPA ROD was tiered to BPA's Business Plan ROD (August 15, 1995) for the Business Plan Environmental Impact Statement (DOE/EIS-0183, June 1995).

The Power Subscription Strategy describes BPA's decisions on a number of issues. These issues include the availability of Federal power, the approach BPA will use in selling power by contract with its customers, the products from which customers can choose, and frameworks for pricing and contracts. The Power Subscription Strategy discussed some issues that would not be finally decided in the Strategy. Most of these remaining issues will be decided in BPA's 2002 power rate case, although some were decided in other forums, such as the transmission rate case, which concluded recently. For example, while the Strategy documents BPA's intention to implement a rate discount for conservation and renewable resources, the final design of that discount was developed in BPA's 2002 power rate case. Other issues to be decided in the 2002 power rate case include the design and application of the Cost Recovery Adjustment Clause (CRAC), which rates apply to which sales, and the design of the Low Density Discount. Customers raised issues regarding the application of other customers' non-Federal resources to serve regional load. These resource issues involve factual determinations under section 3(d) of the Act of August 31, 1964, P.L. 88-552 (Regional Preference Act), and section 9(c) of the Northwest Power Act, 16 U.S.C. § 839f(c) (1994 & Supp. III 1997), which BPA could not address in the Power Subscription Strategy and which were not made a part of the decisions in the Subscription Strategy ROD.

B. Power Subscription Strategy Supplemental ROD

BPA's 1998 Power Subscription Strategy served to guide BPA in accomplishing its goals. After adoption of the Strategy, however, developments occurred that prompted BPA to seek, in some instances, additional comment from customers and constituents on new issues. The Strategy contemplated further public processes to implement its goals. BPA's initial proposal for the 2002 power rates, which began in August 1999, was completed on May 8, 2000 (although its was subsequently amended). BPA and its customers continued discussions on power products and power sales contract prototypes, and the Slice of System product was further defined. In a December 2, 1999 letter, BPA sought comment from customers and constituents on some of these new issues; specifically, the length of the Subscription window for power sales contract offers, the actions required of new small utilities during this window to qualify for firm power service, and new developments with respect to General Transfer Agreements. Other issues arose independently, such as new large single loads (NLSL) under the Northwest Power Act, duration of the new power sales contracts, and a new contract clause regarding corporate citizenship. BPA also undertook a comment process on the amount and allocation of power and financial benefits to provide the IOUs on behalf of their residential and small farm consumers.

C. BPA's Section 5(b)/9(c) Policy

As BPA recognized that its existing long-term power sales contracts would soon expire, BPA proposed to establish a policy to guide the agency in making determinations of the net requirements of its utility customers in order to offer Federal power under new contracts. (For the most part, existing power sales contracts expire by October 1, 2001). A net requirements policy is an important component to BPA's execution and implementation of new power sales contracts. Under section 5(b)(1) of the Northwest Power Act, BPA is obligated to offer a contract to each requesting public body, cooperative, and investor-owned utility to meet each utility's regional firm load net of the resources used by the utility to serve its firm power consumer load. 16 U.S.C. § 839c(b)(1) (1994 & Supp. III 1997). In making this determination, BPA has a corresponding duty to apply the provisions of section 9(c) of the Northwest Power Act, 16 U.S.C. § 839f(c) (1994 & Supp. III 1997), and section 3(d) of the Regional Preference Act, 16 U.S.C. § 837b(d) (1994 & Supp. III 1997).

BPA provided two opportunities for public review and comment in developing its proposed 5(b)/9(c) policy. On May 6, 1999, BPA published its initial policy proposal, entitled "Opportunity for Public Comment Regarding Bonneville Power Administration's Subscription Power Sales to Customers and Customer's Sale of Firm Resources," 64 Fed. Reg. 24,376 (1999). BPA held two public meetings to discuss this policy. The first meeting was held on May 27, 1999, in Spokane, Washington. The second meeting was held on June 2, 1999, in Portland, Oregon. On June 3, 1999, the thirty-day comment period was extended by BPA through June 30, 1999.

After reviewing and considering the comments received on the initial policy proposal, particularly those that requested that BPA provide a second round of review and comment, BPA issued a revised policy proposal on October 28, 1999, entitled "Revised Draft Policy Proposal Regarding Subscription Power Sales to Customers and Customer's Sales of Firm Resources," 64 Fed. Reg. 58,039 (1999). BPA reviewed and considered the comments received on the revised policy. On May 24, 2000, BPA issued its final "Policy on Determining Net Requirements of Pacific Northwest Utility Customers under Sections 5(b)(1) and 9(c) of the Northwest Power Act," also called BPA's "Section 5(b)/9(c) Policy." BPA also issued a Section 5(b)/9(c) Policy Record of Decision.

D. BPA's 2002 Wholesale Power Rate Case

On August 13, 1999, BPA published a notice of BPA's 2002 Proposed Wholesale Power Rate Adjustment, Public Hearing, and Opportunities for Public Review and Comment. 64 Fed. Reg. 44,318 (1999). This began a lengthy and complex hearing process that concluded with BPA's 2002 Final Power Rate Proposal, Administrator's Record of Decision, in May 2000 (May Proposal). 16 U.S.C. § 839e(i). In July 2000, BPA filed its proposed 2002 wholesale power rates with the Federal Energy Regulatory Commission (FERC) for confirmation and approval. 16 U.S.C. § 839e(a)(2). Subsequent to that time, however, during the late spring and summer months, the West Coast power markets suffered price increases and volatility that had not been seen before. By August, it was clear that these market prices were not a short-term phenomenon. This meant that BPA's cost-based rates, which were already below the original market forecast, were even more attractive. Thus, BPA assumed that additional load would be placed on BPA, and BPA would need to purchase additional power to augment the Federal Columbia River Power System (FCRPS) supply. BPA determined that the implications for cost recovery were so serious that a stay of the rate proceeding at FERC was requested. This enabled BPA to review the events that had occurred during the summer months and to determine whether the escalating prices and increased volatility would require remedial action.

Escalating and more volatile market prices had two related effects. First, the specter of higher prices and continued unpredictability caused customers to place as much load as possible on BPA. Second, to meet this increased load obligation, BPA will need to make substantially greater power purchases at substantially higher and more uncertain prices than anticipated in the May Proposal. BPA concluded that the May Proposal, as filed with the FERC, was not adequate to deal with the added costs and financial risks that the high and volatile market prices created for BPA.

During the initial phase of the rate case, BPA's load forecast exceeded BPA's forecast of generation resources by 1,732 average megawatts (aMW). Due to escalating and volatile market prices, BPA estimated that expected loads would exceed the original rate case forecast by an additional 1,518 aMW. Inasmuch as the generating capability of FCRPS was already inadequate to meet the earlier load forecast, BPA would have to purchase power to further augment its inventory to serve these additional loads. The cost of power to serve these unanticipated loads was not included in revenue requirements.

The combination of an unanticipated increase in loads and purchase requirements, with higher and more uncertain market prices, greatly diminished the probability that rates proposed in the May Proposal would fully recover generation function costs. Absent a change to the May Proposal, Treasury Payment Probability (TPP) would be reduced to below 70 percent, a level that would fall well short of specific goals and targets. In its judgment, BPA had a serious cost recovery problem that it was obliged to address by reason of statute and Administration policy.

BPA's Amended Rate Proposal was a continuation of the WP-02 rate proceeding. It was conducted for the discrete purpose of resolving a cost recovery problem brought about by market price trends and load placement changes occurring since the record was closed in the first phase of the proceeding. During the consideration of the Amended Proposal, however, BPA concluded that it was necessary to make additional changes to ensure BPA's cost recovery. BPA then filed a Supplemental Proposal. There were three reasons BPA filed a Supplemental Proposal. First, BPA's forecast for starting rate period reserves had dropped substantially since the forecast in its Amended Proposal. Second, market prices for power during the first two years of the rate period were significantly higher than BPA had forecast in the Amended Proposal. Regardless, BPA would have prepared an update to the Amended Proposal to show the impact of these revised forecasts on BPA's proposed rates. The third reason was that, as a result of discussions with the rate case parties, BPA staff reached a Partial Stipulation and Settlement Agreement with many of those parties. Part of that agreement was that the BPA staff would reflect their understanding of the Partial Stipulation and Settlement Agreement with the Supplemental Proposal for consideration by the Administrator.

The situation has been further complicated by the second lowest runoff year on record, with current runoff forecasted at around 55 million acre feet (MAF). Water Year forecasts in BPA's May Proposal and Amended Proposal assumed average water for both this FY 2001 and for the next five years of the rate period – 102.4 MAF. The current conditions would require BPA to purchase much more power this year than expected to meet loads, at extremely high prices, and to reduce the amount of surplus energy BPA can sell this year. As BPA described in its Amended Proposal, prices in the wholesale electricity market had been extremely volatile and high. In fact, during one week in January alone, BPA purchased over $50 million in power to meet load. This was putting tremendous pressure on BPA's end-of-year reserves. End-of-year reserves translate into starting rate period reserves. In BPA's May Proposal, starting reserves were estimated to be $842 million on an expected value basis. In BPA's Amended Proposal, starting reserves expected value estimates had increased to $929 million. Then, the expected value of BPA's starting reserves estimate dropped to $309 million. There is still a significant range of uncertainty surrounding this estimation of starting reserves. This is driven by some unknown factors for the rest of this fiscal year around hydro operations related to fish requirements, run-off levels, and the volatility in market prices.

Starting reserves are a key risk mitigation tool in BPA's Supplemental Proposal. A significant drop in starting reserve levels, without other adjustments, reduces Treasury Payment Probability (TPP) for the five-year rate period. Therefore, in order to offset this decline, and maintain a TPP level within the acceptable range, adjustments to other tools need to be made.

Market prices during the rate period are higher in the first years of the rate period, ranging from $200/megawatthour (MWh) to $240/MWh for FY 2002, and then dropping during the last years of the rate period, to a range between $40/MWh and $60/MWh in FY 2006. This compares with a risk-adjusted expected price forecast in the Amended Proposal for the five-year rate period around $48/MWh, where expected prices for individual years did not vary by more than $5/MWh from the $48/MWh average.

Because BPA will be in the market purchasing power to serve load during the next five years, BPA's purchase power costs will fluctuate as market prices change. Because the potential levels of power purchases and prices are so great, BPA needs to concern itself not only with annual or rate period totals, but with the seasonal and semi-annual timing of costs and revenues. In order to maintain TPP at an allowable level, all other things being equal, the expected value for the average rate over the five years will be higher with an average flat rate than with a rate shaped to match the expected market. Therefore, BPA revised the LB CRAC so that its expected revenues closely match the shape of its augmentation costs. In summary, BPA's Supplemental Proposal suggested that BPA's customers could see much higher prices during the October 1, 2001, to September 30, 2006, rate period.

E. Administrator's Call for Rate Mitigation Efforts

In March 2001, recognizing the potential for very large adjustments to the rates due to the LB CRAC, BPA began discussions regarding load reduction and the actions being developed by BPA with customers, representatives of the Pacific Northwest States, state utility commissions, and other regional stakeholders. On April 9, 2001, the BPA acting Administrator delivered a speech to the citizens of the Pacific Northwest regarding the potential impact of BPA's proposed rate increase and possible ways to reduce the impact of the increase. In summary, the acting Administrator stated that without certain kinds of action taken by all customers, the first-year increase could be 250 percent or more, likely doubling the retail rates in many utility service areas. An increase of this magnitude would have widespread economic consequences. Thus, before BPA submits its proposed rates to FERC for its review and approval at the end of June 2001, the Administrator is encouraging the region to work together to get the rate increase down to a manageable level.

The speech described the factual crisis situation the region is faced with: historically low water combined with a tight wholesale power market and skyrocketing power prices. At the same time, California's experiment with deregulation helped to drive wholesale electricity prices to unprecedented levels. When BPA completed the execution of new Subscription power contracts last fall, BPA's contractual obligations added up to approximately 11,000 megawatts--about 3,000 megawatts more than BPA's current generating resources can provide on a firm basis. Absent significant load reduction, the only way BPA can meet its obligations is to buy the vast majority of the additional power in a wholesale power market where supplies are tight and prices are sky high.

The speech called upon the region to focus on what the region and BPA can do now to minimize the size of the coming wholesale rate increase. The most immediate and direct way to decrease the size of next year's rate increase is quite simply to decrease the amount of power BPA has to buy in the market. This calls for aggressive and immediate steps from all customer groups to reduce the size of the rate increase by reducing the amount of electricity demand put on BPA. It could keep the first-year rate increase below 100 percent.

The speech called for a three-pronged approach: curtailment of power use, conservation--or more efficient use of power, and power buybacks. This needs to happen across all four states, across public and private power, and across all sectors of energy use--industrial, commercial, agricultural, and residential. The speech called on BPA's preference customers to make a contribution to the solution by requesting every utility customer to reduce its Subscription purchases from BPA by 5 to 10 percent. BPA's rate increases will spur some of this reduction, but more focused efforts are needed to achieve significant savings. BPA indicated that it would be willing to make modest incentive payments to help achieve utility reductions, but the incentive payments cannot be large or they will defeat the intended effect.

The speech also touched on the longer-term solutions that will help lead to lowering the high wholesale power supply prices currently being experienced. The fundamental problem is supply and demand being out of balance. Prompt infrastructure investments are needed in generating resources, especially gas-fired and wind-powered generation; gas pipeline capacity and storage; electric power transmission facilities; and energy conservation measures. If wholesale power prices can be brought down quickly, through infrastructure investments and other actions, then BPA's rates will come down in the future. The faster these actions can be taken, the quicker those rates can come down.

Thus, the acting Administrator asked regional customers to contribute to the mitigation of BPA's potentially high rate increases. Under the rates proposed in the 2002 Draft Supplemental Record of Decision for Wholesale Power Rate Proposal (May 2001), the Administrator proposed a rate structure that will be adjusted every six months, based on actual costs of purchasing firm power to serve BPA's firm power load. That rate adjustment (called the Load-Based Cost Recovery Adjustment Clause or LB CRAC) proposal must be submitted to the FERC at the end of June 2001, in order to have interim approval to go into effect in October of 2001, when BPA's current power rates expire. The LB CRAC adjustment calls for a determination by July 1, 2001, of the amount of power BPA must acquire to serve firm loads for the first six months of the rate period. Therefore, all actions that customers will take to reduce their subscription load must be committed to by contract before June 22, 2001, in order to be included in the first LB CRAC calculation. The acting Administrator's reasoning regarding the various strategies for achieving actual reduction in preference customer load is addressed below.

III. Actions Available to Preference Customers to Reduce Load

The acting Administrator's speech called for customers to reduce their power purchases on BPA by ten percent from October 1, 2001 through September 30, 2003. In aggregate, a ten percent load reduction equates to about 600 aMW from preference customers who are purchasing under either Subscription load-following, Slice/Block, or pre-Subscription contracts. From an operational and contractual standpoint, BPA has taken into account the fact that not all preference customers operate alike, nor purchase the same power products from BPA. With these differences in mind, BPA developed a set of actions (a toolkit) for its customer account executives to use with their customers to achieve their individual 10 percent load reduction. For example, customers wanting to take multiple actions to achieve their load reduction may enter into an "overarching" or umbrella-like agreement which will identify those specific contractual actions. The overarching agreement may alternatively contain only a single action to be taken by the customer which will achieve its load reduction.

The following comprise the toolkit of actions available to customers to achieve their ten percent load reduction.

- *Conservation*. Continue conservation/augmentation programs, including regionwide Vending Mi$er, compact fluorescent lighting, and the invitation to reduce load through conservation (IRLC).

- *Retail rate redesign.* Utility customers may, on their own, implement a redesign of their retail rates to induce more efficient use of electricity.

- *End-use consumer generation.* An end-use consumer will apply its own generation, i.e., cogeneration or emergency backup generation, to serve its own needs or to supply the consumer's serving utility.

- *Addition of utility customer generating resources*. BPA agrees by contract to allow preference and IOU customers to add and use generating resource(s) to serve their loads for the mitigation period. These are small resources or contract purchases that were unplanned prior to this time and which are being added only to replace an amount of the customer's power purchase obligation on BPA (up to the full ten percent load reduction requested by BPA). Such resources do not include larger resources or power purchase contracts that were previously planned by the customer. BPA anticipates that customers will obtain generating resources in a variety of ways, such as leases, contract purchases of output, or construction. Some customers may take such actions consistent with BPA's recently proposed Temporary Small Resource Policy. That policy is subject to a separate ROD and NEPA consideration and is not within the scope of this Strategy. As discussed in greater detail below, at the end of the rate mitigation period, BPA anticipates supplying the ten percent of load through planned power acquisitions; customers who add resources pursuant to this Strategy may then remove such resources and sell the amount of power used for the ten percent load reduction in the wholesale power market.

- *Rate mitigation replacement product*. BPA requests that all preference customers pursue an amount of load reduction, including its full service requirements customers. Full service customers generally purchase all of their power from BPA and have either no resources of their own or very small non-dispatchable resources. Such customers have small net requirement loads and do not purchase power from the volatile market. Therefore, BPA developed a rate mitigation replacement product that is available only to full service customers. Under the rate mitigation replacement product an eligible customer has two choices: (1) identify an amount of firm power, including temporary surplus firm power, to be repriced at market under the FPS rate schedule, as provided under Exhibit D of the customer's Subscription contract; or (2) identify an amount of firm power for replacement by an equivalent amount of surplus firm power priced at market under the FPS rate schedule under Exhibit C of the Subscription contract. BPA expects the total amount of the rate mitigation replacement product taken by full service customers will be small and most likely will not exceed 50 aMW. Surplus firm power will be made available either by allocating power intended for augmentation or by purchasing a minimal block of power from the market.

- *Non-load following customer rate mitigation commitment*. Customers purchasing non-load following products, such as a block of firm power, may contractually commit to reduce, by a specified amount, power from their fixed purchase obligation under contract. Under this action BPA agrees to a so-called "buy-back" of the amount of power the customer specifies for reduction.

- *Voluntary load reduction.* The customer and BPA may contract to have the customer enter into an agreement with a specific retail consumer to curtail, i.e., voluntarily reduce, its electricity consumption. Actions that can be taken include: irrigation load reduction, demand exchange, and retail industrial consumer load buydowns.

While BPA believes that much of the load reduction it seeks will result from customers taking the above actions, BPA also believes that load reduction will also come about simply by being price-induced.

IV. Contract Amendment Offers and Contingency Clause

In making available the above contract actions, BPA will include a contingency clause to allow a customer to terminate its contractual obligation to perform a selected action if certain conditions occur. The following describes the conditions for termination.

- The first condition occurs if the WP-2002 Final Supplemental Wholesale Power Rate Record of Decision (ROD) does not adopt the LB CRAC mechanism. This contingency is necessary because these contracts will be signed prior to the issuance of the Rate Case ROD.

- The second condition is a “test” that must be met to ensure that all customers are performing as expected, assuming the Administrator does adopt the LB CRAC mechanism in the Power Rate Case ROD. The test is intended to indicate whether customers are engaged in rate mitigation actions that will assure that the October rate increase does not exceed 87 percent, considering the level of the market clearing price of power.

- Third, the contingency clause provides that if the Administrator adopts the LB CRAC in the Power Rate Case ROD, and the rate mitigation efforts exceed the amount necessary to reduce market power purchases below 2,200 aMW per month, the additional load reduction will be used to reduce the level of the LB CRAC.

- Fourth, BPA added termination language to the contingency clause to address concerns raised by preference customers that their actions may result in a rate increase low enough for the economical operations of the DSIs, which would then again put upward pressure on the LB CRAC.

V. Determination of Utility Customer Exports of Unplanned Resources Under Section 9 of The Northwest Power Act

As stated above, one of the actions that can be taken by a utility customer to reduce a portion of its BPA served load during the first two years of its Subscription contract is to contractually add a generating resource(s) to serve such load obligation. These resources are unplanned since neither BPA nor the customer expected to add them during the term of the Subscription contract. The addition of these unplanned resources is due to BPA’s call for its customers to reduce their load on BPA by ten percent in order to reduce the increase in BPA’s wholesale power rates. BPA otherwise is contractually obligated to serve such portion of the customer’s load. BPA has examined and analyzed several factors which lead BPA to conclude that unplanned resources added by a utility customer pursuant to this Strategy may be removed by the customer and resold in the market during the 2003 through 2006 period. BPA has also determined that during this period such resource(s) may be exported from the region consistent with section 9(c) of the Northwest Power Act. <u>See</u> Appendix, Section 9(c) Export Determination Study for Unplanned Resources (Study).

BPA has a statutory duty under Public Law 96-501, section 9(c) of the Northwest Power Act, 16 U.S.C. § 839f(c), to determine whether the export of unplanned resources by utility customers during the period FY 2002 through 2006 will result in an increase in the electric power requirements of BPA or any of its customers and whether the resource could be conserved or otherwise retained to serve regional load in the Pacific Northwest. If BPA finds that the export of a resource would result in an increase in the electric power requirements of any of its customers under BPA’s Northwest Power Act, Section 5(b) utility power sales contracts, and the resource could have been conserved or otherwise retained to serve regional loads, BPA is required to reduce its firm load obligation to deliver power and energy under the exporting utility’s power sales contract, effective on a date certain up to the amount of the export sale and for the duration of such sale. If, on the other hand, BPA finds that the export of the Pacific Northwest resource would not result in any increase in the electric power requirements of BPA for that customer or any other customer, or BPA further finds that the energy could not be reasonably conserved or otherwise retained for service to regional load by reasonable measures then BPA will not decrease its obligation to the exporting utility under its power sales contracts.

In implementing section 9(c), BPA must reasonably balance the risk between BPA becoming obligated to acquire additional resources which it otherwise would not plan to serve additional load obligations, with the customers' ability to export unplanned resources. In making this determination, BPA is taking into account the current power situation. BPA's contractual obligations to serve regional customers' load during the next rate period exceeds BPA's firm resources. See Study. In order to otherwise meet its contractual obligations BPA is faced with having to purchase power from a historically high priced and volatile market, the cost of which must be recovered in the rates BPA charges its customers. Considering the economic impact such purchases would have on BPA's rates, BPA is requesting regional customers to reduce their BPA served loads for the first two years of the rate period. Such action by its customers will result in a reduction in BPA's contractual obligation to serve and reduce the amount of high priced power costs to be included in BPA's rates.

Utility customers reducing a portion of their BPA served load by adding unplanned resources are doing so in the first one or two years of the rate period. These unplanned resources will be used as bridge resources to transition between today's expensive market and the lower cost period expected in 2003. See Study. It is both uneconomical and difficult, however, for customers to purchase and add unplanned resources in the first two years only. As a general matter, most resources that are available now to customers to meet their load reduction during the two year period are expensive and only economic or available for five year periods. See Study, Table 2. At five years such resources become more economical to operate because the customer is in a better position to recover its resource cost.

BPA expects today's resource and market conditions to change within the next two to three years with generation supply being added to the region and market prices dropping. BPA concludes that it will then have an adequate and economical power supply to meet all of its contractual obligations, including resumption of service to customer reduced load. Not only is BPA expecting the region to be in a load–resource balance in 2003, but BPA also expects the price of power available in the market to drop significantly from today's high prices.[2] Therefore, BPA has determined that future exports by a utility customer of its unplanned resource(s) will not result in any increase in the electric power requirements of BPA for that customer or any other customer. In addition, given the high cost of such unplanned resources and the expected lower cost resources and reduced market prices, BPA finds that these unplanned resources cannot be reasonably conserved or otherwise retained for service to regional load.

[2] BPA will examine the level of its rates expected for the second year, as well as the availability of cost effective power in the market. If BPA's rates and market prices are expected to be high, then BPA will request its utility customers to continue using their unplanned resources.

VI. NEPA Review

The Strategy For Utility Customer Load Reduction Under Subscription Power Sales Contracts And Utility Customer Export of Unplanned Resources Under Section 9(c) of the Northwest Power Act is consistent with BPA's Business Plan Record of Decision (ROD), signed August 15, 1995, BPA's Business Plan Environmental Impact Study (EIS), and the subsequent Power Subscription Strategy ROD, signed December 21, 1998. The Strategy ROD is a direct application of BPA's earlier decision to adopt a market-driven approach for participation in the increasingly competitive electric power market.

VII. Conclusion

Events transpiring in the wholesale power market necessitate that BPA and its customers take actions to mitigate the adverse impact such events are having on BPA and the region's economy. BPA's power supply obligations exceed the capability of BPA's system. In meeting these obligations BPA and its customers have alternatives. On the one hand, BPA and its customers can stay the course and have BPA purchase power from the high priced and volatile market. Such costs, if incurred, would need to be recovered through BPA's rates. On the other hand, BPA and its customers can work together to reduce BPA's load obligations and reduce the level of BPA's rates becoming effective October 1, 2001. BPA and its customers are agreeing to work together toward a goal to reduce by ten percent the load currently on BPA. Under this Strategy, BPA has developed actions which I believe will achieve the ten percent goal. In addition, this Strategy and the accompanying Northwest Power Act section 9(c) determination allows BPA's utility customers to add and use unplanned resources to meet their ten percent load reduction and to export such unplanned resources when subsequently removed from utility load service.

Issued in Portland, Oregon, on June 15, 2001.

/ S / Stephen J. Wright
Acting Administrator and Chief Executive Officer

APPENDIX
Section 9(c) Export Determination Study for Unplanned Resources
Fiscal Years 2002 through 2006

Background

In the fall of 2000, BPA completed its subscription process with the signing of new power sales contracts with its customers in the Pacific Northwest. These customers signed contracts that total about 11,000 aMW. BPA's system, composed of 30 hydroelectric projects, one nuclear plant, and several non-federal projects, generally produces about 8,500 aMW of electricity on a planning basis each fiscal year. Therefore, BPA will need to purchase energy in the marketplace in order to meet its contractual obligations for the entire 5-year period of this study.

During the past few months, BPA has developed a Load Reduction Strategy to mitigate the impacts of current high and volatile market power prices on the rates that it will charge its wholesale customers beginning October 1, 2001, by encouraging customers to reduce their purchases from BPA by up to 2400 aMW in the short term, until expected moderation in market prices occurs. See BPA's Load Reduction Strategy ROD. At that time, BPA will serve its entire contractual sales obligation to these customers.

As described in the Load Reduction Strategy ROD, one of the options available to public utility customers and IOUs for reducing their loads is the addition of unplanned resources - new generating units or contract resources - that can be brought on-line in a short time period. This 9(c) study shows that most of these resources burn natural gas or diesel fuel, and are higher-cost resources than the larger and more efficient generating resources that take more time to plan, permit, and site before coming on-line.

The following analysis demonstrates that it is highly likely that BPA will be able to purchase power in FY 2003 or FY 2004 and beyond at market prices that are lower than the cost of operating these unplanned higher cost resources, and therefore makes a determination that the amounts of these resources applied to loads can be exported from the region.

Federal and Regional Load Resource Balances

BPA's 1999 Pacific Northwest Loads and Resources Study (White Book), adjusted for the loads presented in the Amended Proposal for BPA's 2000 Power Rate Case, shows that BPA's expected load obligations resulting from Subscription will exceed the resource capability of the federal system in each year from FY 2002 through FY 2006 (see Table 1).

Table 1
BPA and Regional Load Resource Balances
FY 2002 through FY 2006

Fiscal Year	**BPA System Load Resource Deficit**	**PNW Regional Load Resource Deficit**
FY 2002	-2120 aMW	-3539 aMW
FY 2003	-2226 aMW	-3831 aMW
FY 2004	-2144 aMW	-3821 aMW
FY 2005	-2252 aMW	-3880 aMW
FY 2006	-2383 aMW	-3806 aMW

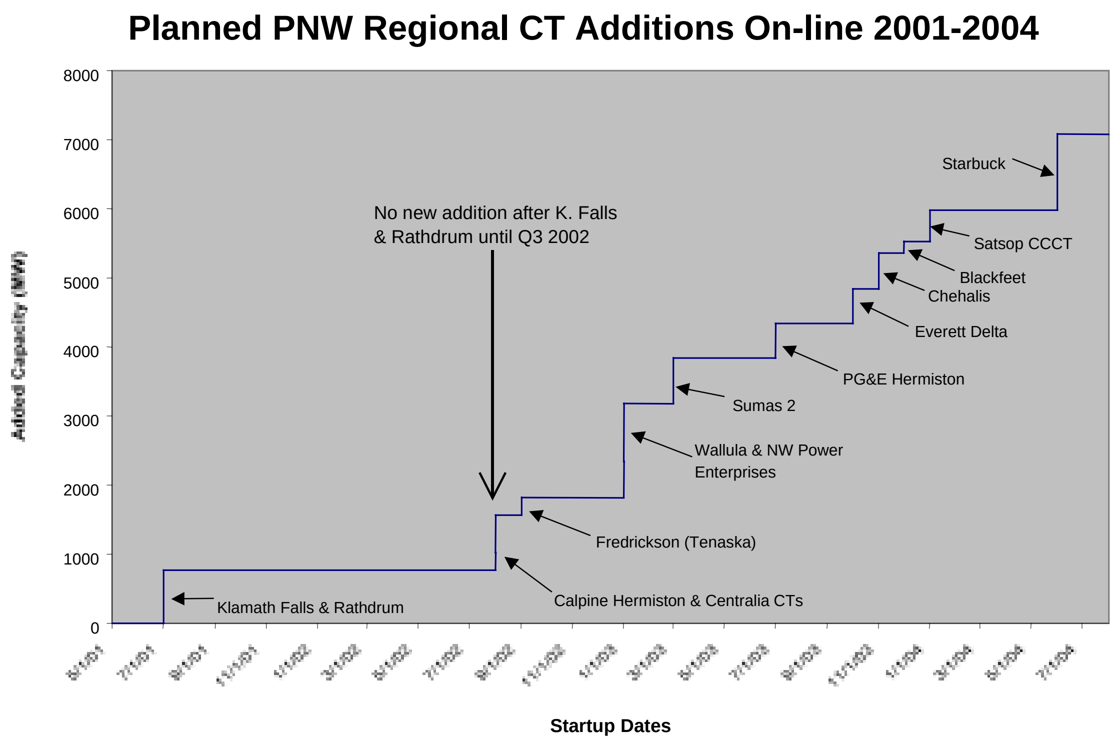
See Attachment 1 (Appendix page 7) for details.

In addition, again based on the 1999 White Book, Table 1 shows that the Pacific Northwest region is expected to be deficit as well during these same 5 years. Neither of these studies takes into account the resource additions expected to come on-line over the next few years.

Plans to build new generating resources have multiplied recently as high wholesale electricity prices have created price signals that are causing accelerated development of generating resources throughout the PNW. As a result, the regional balance of supply and demand will change dramatically beginning in 2003, when, over a 12-month period, over 5,000 aMW of natural gas-fired combined cycle combustion turbines (both utility and merchant plants) is scheduled to come on-line in the region, as shown in Figure 1.

Furthermore, this total does not include an additional 450 aMW of wind generation expected to be added by 2003. In addition, Attachment 2 (Appendix page 8) shows all expected resource additions for the PNW over the next few years, which total about 20,000 aMW. Based on these resource plans, BPA anticipates that the region will be in a load–resource balance by the beginning of FY 2004, if not before, and BPA will therefore be able to meet its firm load obligations through the purchase of output from these new resources.

Figure 1

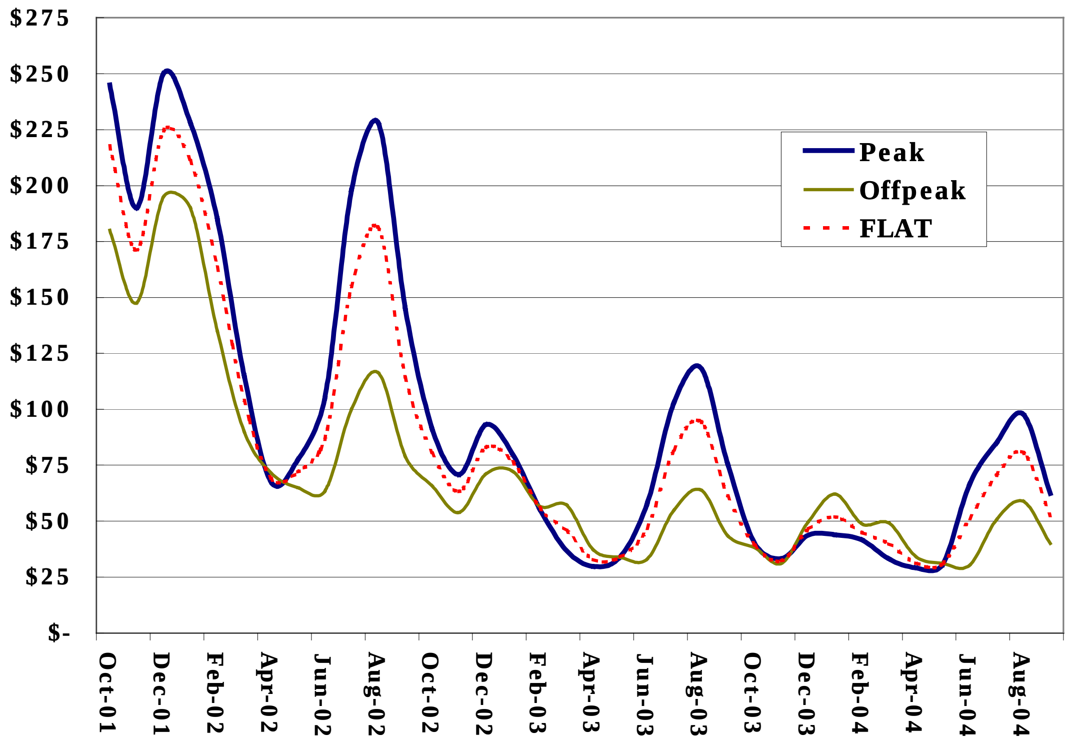


In addition, as shown in Attachment 3 (Appendix page 14), as much as 42,000 aMW of generation is planned to be on line in California by the end of this 5 year period. Since the West Coast functions as a single market much of the time, these resource additions will create downward pressure on market prices by 2003. As a result, market prices are expected to come down significantly in that same time frame as supply more closely matches demand.

Future Wholesale Market Prices

Future wholesale electricity prices are already reflecting this anticipated change in the region's supply situation. Prices that traders are quoting, as illustrated in Figure 2, show dramatic declines in FY 2003 and 2004 when the forward price drops to about $55 per MWh for the year – a dramatic decline from the average of about $150 for FY 2002**.** This forward price curve

Figure 2
Forward Price Curve FY 02 to FY 04
Based on quotes from Morgan Stanley



demonstrates a wholesale market that is "backwardated," meaning that prices are lower in the longer term than in the near term. This price pattern indicates that buyers and sellers are considering the large amount of future new generation in the region, and in California, when selling and purchasing power now for delivery in the future.

In addition, quotes that BPA's trading floor received in early June reflect further decreases in these prices from the mid-$50s per MWh to the mid-$40s. These forward prices are approaching the embedded cost of a new combined cycle combustion turbine, estimated to be between $45 and $55 for a unit with a 7000 Btu heat rate and gas prices in the range of $4 to $5/mmBtu**.**

Table 2
Projected Market Prices for Electricity
Used in BPA's 2000 Power Rate Case

Fiscal Year	Projected Market Price ($/MWh)
FY 2002	$148
FY 2003	$63
FY 2004	$46
FY 2005	$50
FY 2006	$49

Note: prices for FY 02 and FY 03 are based on market quotes while the prices for the last 3 years come from the Aurora model.

Further evidence of a backwardated market is shown in BPA's Risk Analysis Studies for the Amended Proposal and the Final Supplemental Proposal for the 2000 Power Rate Case. Table 2 shows projected market prices for flat energy dropping from $148 in FY 2002 to an average of $48 for the final 3 years of the rate period.

Types and Costs of Likely Unplanned Resources

The types of unplanned resources that BPA expects its preference and IOU customers to acquire to meet their load reductions are outlined in Table 3.[3] All are resources with capacity that is less than 50 MW. With the exception of wind, their fuel sources are natural gas or diesel fuel. These resource types are the major ones that can be acquired and brought on-line in a short timeframe – which is necessary since the load reduction commitments signed in June 2001 will take effect on October 1, 2001. As illustrated in the table, these resource types are comparatively higher in cost than the prices for FY03 and beyond shown in Figure 2. Flat forward prices drop to just above $50 per MWh by the end of 2004, yet the operating costs of the above technologies range from $57 to $164. These costs all exceed the forward price significantly, except for the LM6000s. This simple CT, however, is unlikely to be able to be brought on–line in the time frame of the Load Reduction Strategy, but it was included in the table.

[3] BPA does not consider a utility with a market resource that is used to meet the utility's load reduction to be a planned resource used to serve regional firm load. BPA considers such resource use to be unplanned. See Administrator's Record of Decision, Non-Federal Participation Capacity Ownership Contracts and Section 9(c) Policy, at B-14, (July, 1994).

Table 3

Model	Technology	Average Heat Rate (BTU/kWh)	Fuel Type	Fuel Price ($/MMBTU)	Fuel Tax ($/unit)	O&M ($/MWh)	Total Fixed Costs ($/MWh)	Approx. Total Production Cost ($/MWh)
GE LM6000	Simple, aero, CT	8,300	N.Gas	5.0	0.00	3	12	57
GE Jenbacher JGC 320GS	Reciprocating	9,500	N.Gas	5.0	0.00	12	69	129
Caterpillar 3516B	Reciprocating	9,500	Diesel	8.5	0.00	23	60	164
Vestas 660kW	H-axis wind turbine	0	Wind	0.0	0	7	67	73

Notes:
Wind production costs do not include the $17/MWh federal tax credit subsidy.
Reciprocating gensets are amortized over a 24 month period at 4.5% interest.
The simple cycle CT and the wind turbines are amortized over a 30 year period at 6% interest.
A 90% operating factor is assumed for the reciprocating gensets
A 30% operating factor is assumed for the wind turbines.

Note: Information that forms the basis for the above table came from various EPRI studies, the manufacturers of this equipment, and internal BPA analysis.

Conclusion

In conclusion, analysis of loads and resources for BPA and the Pacific Northwest for the period 2001 through 2003 confirms that the current resource and market situation should moderate, with market prices more closely reflecting the underlying costs of newly built generating resources. Currently scheduled additions to the regional supply of electricity will more than off-set BPA's expected deficits as load reduction obligations terminate in 2003 and beyond.

Based on the analysis of the above factors, BPA makes the following determination pursuant to section 9(c) of the Northwest Power Act regarding the future export of unplanned resources used by preference customers and IOU customers to serve their load reduction commitments. BPA does not believe that sales of these amounts of unplanned resources outside the Pacific Northwest by utility customers will affect BPA's obligation to meet their loads nor the loads of other customers in the region. Further, based on the high costs of unplanned resources compared to the lower-cost planned resources and the backwardated market prices, BPA does not believe such unplanned resources could be retained or otherwise conserved for use in the region.

Attachment 1

Adjusted Federal Surplus/ Deficit from the 1999 White Book

1999 White Book Adjusted Federal Surplus/Deficit					
Adjusted for Augmentation through 8/1/2000					
Fiscal Year					
Energy in Megawatts	**FY 2002**	**FY 2003**	**FY 2004**	**FY 2005**	**FY 2006**
1. 1999 Federal S/D	**-1030**	**-1135**	**-1053**	**-1161**	**-1076**
Firm Load Changes ("-" indicated Load Increase)					
Additional Public Load	-1400	-1400	-1400	-1400	-1400
Additional DSI Load	-49	-49	-49	-49	-49
2. Total Load Change	**-1449**	**-1449**	**-1449**	**-1449**	**-1449**
Firm Contract Changes ("+" indicates Resource Increase)					
Other Entities to BPA Pwr Sale	358	358	358	358	142
3. Total Contract Changes	**358**	**358**	**358**	**358**	**142**
4. Total Load Resource Adjustments	**-1091**	**-1091**	**-1091**	**-1091**	**-1307**
(line 2 + 3)					
5. 1999 Adjusted Federal S/D	**-2120**	**-2226**	**-2144**	**-2252**	**-2383**
(line 1 + 4)					
Based on 1999 White Book dated 12/31/99					
Note: Adjustments included public and DSI load changes and					
purchases from other entities made before 8/1/2000.					

Attachment 2

Derived From
Northwest Power Planning Council
PLANNED GENERATING PROJECT ACTIVITY IN THE PACIFIC NORTHWEST
June 11, 2001

(see key p. 13)

Project	Project Type	Technology	Fuel	MW Capacity	On-line date
Air Liquide	TG	FO2	IC	9.6	
Arrowrock Dam	G	WAT	HY	56.0	
Ash Grove Cement	TG	FO2	IC	8.0	
Athol	TG	FO2	IC	1.6	Mar-01
B&G Farms (Adams Rd.)	TG	FO2	IC	10.0	May-01
B&G Farms (Frenchman Hills)	TG	FO2	IC	10.0	May-01
B&G Farms (Jericho)	TG	FO2	IC	12.6	May-01
Bains	TG	FO2	IC	2.5	May-01
Bear Creek	G	WAT	HY	4.0	
Beaver GT	G	NG	GT	24.5	Jul-01
Bellingham Cold Storage	TG	FO2	IC	2.0	Mar-01
Benton PUD	G	NG	GT	27.0	Nov-01
Big Hanaford	G	NG	CC	248.0	Jul-02
Blackfeet Wind	G	WND	WT	50.0	Oct-02
Boardman GT	G	NG	GT	47.0	Dec-01
Boardman Turbine Upgrade	G	COL	ST	65.0	Sep-00
Bonneville First Powerhouse R&B	XG	WAT	HY Eff		Dec-03
Boundary Runner Replacement	XG	WAT	HY Eff		Jun-03
BP Cherry Point CC	G	NG	CCCG	750.0	
BP Cherry Point GTs	G	NG	GT	73.0	
BP Cherry Point ICs	TG	FO2	IC	26.0	Mar-01
Cabinet Gorge Addition	XG	WAT	HY	60.0	
Cabinet Gorge Unit #2 Turbine Replacement	XG	WAT	HY Eff	12.0	2001
Cabinet Gorge Unit #3 Turbine Replacement	XG	WAT	HY Eff	12.0	2002
Cabinet Gorge Unit #4 Turbine Replacement	XG	WAT	HY Eff	12.0	2003
Calligan Creek	G	WAT	HY		
Calpine (Alcoa)	G	NG	GT	88.0	
Cenex	TG	FO2	IC	20.0	
Chehalis Generating Facility	G	NG	CC	520.0	
Chelan Co. PUD ICs	TG	FO2	IC	33.6	May-01
City of Albany	XS/NG	WAT	HY	0.5	
City of Anacortes	TG	FO2	IC	1.8	Dec-00
Clark Public Utilities ICs	TG	NG	IC	50.0	Jul-01
Clearwater Creek	G	WAT	HY	6.0	
CNC Containers	TG	FO2	IC	24.0	Nov-00
Coffin Butte Expansion	XG	LG	IC	2.5	
Condit (Removal)	XG	WAT	HY	(14.7)	

Project	Project Type	Technology	Fuel	MW Capacity	On-line date
Condon	G	WND	WT	49.8	Jun-02
Connell's Prairie (White River Project)	G	WAT	HY	14.0	
CONOCO	TG	FO2	IC	19.0	
Cowlitz Co. PUD GTs	TG	NG	GT	13.5	Jul-01
Cowlitz Co. PUD ICs Ph 1	TG	NG	IC	6.0	Jun-01
Cowlitz Co. PUD ICs Ph 2	TG	NG	IC	15.0	Oct-01
Cowlitz Co. PUD ICs Ph 3	TG	NG	IC	14.0	Nov-01
Cowlitz Cogeneration	G	NG	CCCG		
Coyote Springs 1 Upgrades	XG	NG	CC	5.0	Jun-01
Coyote Springs 2	G	NG	CC	280.0	Jun-02
Crossroads Conduit	G	WAT	HY		
Decker Coal	TG	FO2	IC	6.4	
Dworshak (Clearwater Hatchery)	G	WAT	HY	2.9	Jul-00
Elwha (Removal)	XG	WAT	HY	(12.0)	
Energy Northwest ICs	TG	FO2	IC		
Equilon GTs	G	NG	GT	38.5	
Equilon ICs	TG	FO2	IC	37.5	
Everett Delta 1	G	NG	CC	245.0	
Everett Delta 2	G	NG	CC	245.0	
Exxon Ph 1	TG	NG/RG	GT	20.0	
Exxon Ph 2	TG	NG/RG	GT	10.0	
Faraday Rehabilitation	XG	WAT	HY Eff	1.7	
Foote Creek Rim IV	G	WND	WT	16.8	Oct-00
Fourmile Hill	G	GST	GE	49.9	10/1/04
Franklin/Grays Harbor CTs	G	NG	GT	44.0	Dec-01
Frederickson (Westcoast)	G	NG	CC	249.0	Sep-02
Fredonia Addition	G	NG	GT	106.0	Aug-01
Garnet Energy Facility	G	NG	CC	273.0	2004
Georgia-Pacific (Bellingham) GTs	G	NG	GT	20.0	
Georgia-Pacific (Bellingham) ICs	TG	FO2	IC	19.2	Jan-01
Gillihan	G	WAT	HY	0.0	
Gilmer	TG	FO2	IC	6.0	
Glines Canyon Removal	XG	WAT	HY		
GNA GT 1-4	G	NG	GT	190.0	Feb-02
Goldendale Energy Center	G	NG	CC	248.0	Jul-02
Gorge Companion Tunnel	XG	WAT	HY Eff	20.0	
Grand Coulee 1 - 18 Runner Repl.	XG	WAT	HY Eff	0.0	Dec-07
Grant Co. PUD ICs	TG	FO2	IC	32.0	Jun-01
Grays Harbor Co. PUD ICs	G	FO2	IC	12.0	Jul-01
Grizzly	G	NG	CC	980.0	
Gunkel Orchards	TG	FO2	IC	3.2	May-01
H.W. Hill Expansion	G	NG	IC	10.5	
Hancock Creek	G	WAT	HY		
Hermiston Power Project 1 & 2	G	NG	CCCG	536.0	Jun-02
Holnam Cement	TG	FO2	IC	6.0	
Ice Harbor R&B	XG	WAT	HY Eff		

Project	Project Type	Technology	Fuel	MW Capacity	On-line date
Idaho Power ICs	TG	FO2	IC	40.0	Jun-01
Kettle Falls Upgrade	XG	NG	GT	6.0	
Klamath Cogeneration Project	G	NG	CCCG	484.0	Jul-01
Klamath GTs	TG	NG	GT	100.0	Nov-01
Kootenai Power Project	G	NG	CC	1300.0	
Lammars	TG	FO2	IC	0.7	
Libby Addition	XG	WAT	HY		
Little Falls Runner Replacement	XG	WAT	HY Eff	0.3	
Lloyd	TG	FO2	IC	0.8	
Long Lake 3 Turbine Replacement	XG	WAT	HY Eff	4.0	Dec-00
Long Lake Addition	XG	WAT	HY	60.0	
Longview Power Station	G	NG	CC	245.0	
Lorz	TG	FO2	IC		
Louisiana Pacific (Missoula)	TG	NG	IC	13.5	
Lower Baker Runner Replacement	XG	WAT	HY Eff	2.0	Jul-01
Maiden Wind Project	G	WND	WT	150.0	Oct-02
Marsh Valley	G	WAT	HY	1.7	
Medite MDF	G	NG	GTCG	6.0	
Mercer Ranch	G	NG	CC	850.0	
Mint Farm	G	NG	CC	249.0	
Miranson (Entiat)	TG	FO2	IC	9.8	
Miranson (Mansfield)	TG	FO2	IC	9.8	
Morrow Power	G	NG	GT	25.0	
Mountain Home (IPC)	G	NG	GT	90.0	Nov-01
Mountain Home (Power Development)	G	NG	GT	90.0	
Nine Canyon	G	WND	WT	50.0	
North Fork Runner Replacement	XG	WAT	HY	3.0	Q3 2001
North Umpqua Project Upgrade	XG	WAT	HY Eff	4.5	
Northeast Washington Mobile Power	TG	FO2	IC		
Northwest Aluminum Wind	G	WND	WT	4.5	Jan-02
Northwest Geothermal Co.	G	GST	GE	30.0	
Northwest Regional Power (Dallesport)	TG	FO2	IC	3.0	
Northwest Regional Power (Hanford)	TG	FO2	IC	28.8	Jun-01
Northwest Regional Power (John Day)	TG	FO2	IC	32.8	May-01
Northwest Regional Power (Rainier)	G	FO2	IC	24.0	
Northwest Regional Power (Rock Island) Ph 1	TG	FO2	IC	32.8	
Northwest Regional Power (Rock Island) Ph 2	G	NG	GT		
Northwest Regional Power (Roosevelt Landfill) Ph 1	TG	FO2	IC	16.0	
Northwest Regional Power (Roosevelt Landfill) Ph 2		NG	GT	15.0	
Northwest Regional Power Facility	G	NG	CC	838.0	
Noxon Rapids 5 Runner Rep & Rewind	XG	WAT	HY Eff	10.0	2005
Noxon Rapids Unit 1 Turbine Replacement	XG	WAT	HY Eff	10.0	
Noxon Rapids Unit 3 Turbine Replacement	XG	WAT	HY Eff	10.0	
Noxon Rapids Unit 4 Turbine Replacement	XG	WAT	HY Eff	10.0	
Okanogan Co. PUD Ph 1	TG	FO2	IC	6.6	

Project	Project Type	Technology	Fuel	MW Capacity	On-line date
Okanogan Co. PUD Ph 2	G	FO2	IC	26.0	Jul-01
Okanogan Power Ph 1	TG	FO2	IC	0.8	Jun-01
Okanogan Power Ph 2	TG	FO2	IC	8.2	
Okanogan Power Ph 3	TG	NG/PG	GT	10.0	
Oregon Energy	G	NG	CCCG	141.0	
Pierce Power	TG	NG	GT	160.0	Sep-01
Pinesdale	G	WAT	HY	0.2	
Ponderay Newsprint	TG	FO2	IC	5.7	Mar-01
Pope & Talbot	G	NG	GTCG	80.0	Mar-02
Port Westward	G	NG	CC	650.0	
Praxair	TG	FO2	IC	5.4	
Priest Rapids Pool Raise	XG	WAT	HY Eff	10.0	
Rail Energy of Montana (Butte)	TG	FO2	IC	9.3	
Rail Energy of Montana (Sappington)	TG	FO2	IC	9.3	
Rail Energy of Montana (Trident)	TG	FO2	IC	9.3	
Rathdrum Power	G	NG	CC	270.0	Aug-01
Reardan	G	FO2	IC	35.0	
Renton Wastewater Fuel Cell	G	WG	FC	1.0	Q3 2002
Rim Rock	TG	FO2	IC	2.5	
Rim View	G	WAT	HY	0.3	Oct-00
River Mill Rehabilitation	XG	WAT	HY Eff	0.6	
Rock Island (New Turbines)	XG	WAT	HY	43.5	
Rocky Reach Powerhouse Rehabilitation	XG	WAT	HY	27.4	Dec-01
Round Butte Runner Replacement	XG	WAT	HY	20.0	2003
Sahko	G	WAT	HY	0.5	
Salt River	G	WAT	HY	1.1	
Satsop	G	NG	CC	630.0	
SDS Lumber ICs	TG	FO2	IC	7.5	
SDS Lumber ST	G	NG/FO/WW	ST	3.5	Jul-01
Seattle City Light ICs	TG	NG	IC	50.0	
Sedro-Wooley Energy Center	G	NG	GT	82.6	Aug-01
Silver Bow	G	NG	CC	500.0	
Simpson Paper	TG	FO2	IC	19.7	
Simpson Ridge	G	WND	WT	375.0	
Skagit Reservoir Optimization	XG	WAT	HY Eff	0.0	Dec-01
Snoqualmie Falls Upgrade	XG	WAT	HY Eff		
SP Newsprint	G	NG	CCCG	119.0	
Springfield	G	NG		9.5	Jul-01
Springfield ICs	TG	FO2	IC	26.7	Apr-01
Starbuck	G	NG	CC	1200.0	
Stateline Phase 1	G	WND	WT	175.0	Dec-01
Stateline Phase 2	G	WND	WT	125.0	Q1 2002
Stone Container	TG	FO2	IC	10.5	
Sullivan Rehabilitation	XG	WAT	HY Eff	1.2	
Sullivan Creek	G	WAT	HY	11.0	
Sumas Energy 2	G	NG	CC	660.0	

Project	Project Type	Technology	Fuel	MW Capacity	On-line date
Summit/Westward	G	NG	CC	520.0	
Tacoma Power IC Expansion	TG	FO2	IC	21.3	
Tacoma Power ICs	TG	FO2	IC	52.5	Jan-01
Taplett (Entiat)	TG	FO2	IC		
Taplett (Wenatchee)	TG	FO2	IC	3.2	
Tesoro Ph 1	TG	FO2	IC	21.6	
Tesoro Ph 2	TG	NG	IC	24.0	
The Dalles 1 - 14 R & B	XG	WAT	HY Eff		
The Dalles 1-14 SS Excitors	XG	WAT	HY Eff		2003
Tiber Dam	G	WAT	HY	7.5	
Tieton	G	WAT	HY		
Titan	TG	FO2	IC	15.0	Jul-01
U.S. Electric Cherry Point	G	COL		249.0	
Umatilla	G	NG	CC	500.0	
Umatilla Generating Project 1 & 2	G	NG	CC	550.0	
Upper Falls Rehabilitation	XG	WAT	HY Eff		
Valley Electric (Black Sands)	TG	NG/FO2	IC	15.0	
Valley Electric (Quincy)	TG	NG/FO2	IC	44.0	
Valley Electric (Wheeler)	TG	NG/FO2	IC	44.0	
Wallula	G	NG	CC	1300.0	
Wanapum 11 & 12	XG	WAT	HY Eff	133.1	
Wanapum Runner Replacement	XG	WAT	HY Eff		
Warm Creek	G	WAT	HY	3.6	
Wells (Governors)	XG	WAT	HY		May-00
West Linn Paper	G	NG	CCCG	94.0	
Willamette Industries (Albany/Millersburg)	G	NG	CCCG	45.0	
WNP-1 Solar	G	Solar	PV	0.1	10/1/01
WNP-2 Upgrade 3	XG	UR	NB Eff		
Youngs Creek	G	WAT	HY	8.3	
Zosel Lumber	G	WD	STCG	3.2	
TOTAL INSTALLED CAPACITY				**20138**	

Key to Attachment 2

ABBREVIATIONS KEY USED IN PROJECT DATABASE

Project Type

TG	Temp Generation (permitted for 24 months or less
G	New permanent power plant
XG	Refurbishment, expansion or retirement of existing plant

Technology

FO2	Distillate Fuel Oil
WAT	Water
NG	Natural Gas
WND	Wind
COL	Coal
LG	Landfill Gas
NG/RG	Natural Gas/Refinery Gas
GST	Geothermal Fluid
NG/PG	Natural Gas/Propane
WG	Wastewater Treatment Plant Gas
NG/FO/WW	Natural gas/fuel oil/waste water
NG/FO2	Natural gas/fuel oil
UR	Uranium

Fuel

IC	Reciprocating Engine
HY	Hydropower
GT	Gas Turbine
CC	Combined-Cycle Combustion Turbine
WT	Wind Turbine
ST	Boiler Steam Turbine
HY Eff	Hydropower Efficiency Improvements
CCCG	Combined-Cycle Combustion Turbine Cogeneration
GTCG	Geothermal Cogeneration
GE	Geothermal Plant
PV	Photovoltaic
NB Eff	Boiling Water Reactor Efficiency Improvements
STCG	Boiler Steam Turbine Cogeneration

Attachment 3
Sited California Generation Projects - On Line 2001-2007
(source: Industrial Information Research)

Facility	Technology	Output (MW)	Est Online Date
GRAND TOTAL		**42,013**	
FY 01			
Mountain View Power Partners	Wind	50	4/1/01
Procter & Gamble		44	4/1/01
South Point		545	5/1/01
Desert Basin Generating		500	6/1/01
Griffith Energy Project	CCCT	520	7/1/01
Los Medanos (Pittsburg) Facility	CCCT	500	7/1/01
Sutter Power	CCCT	500	7/1/01
CEC Renewables Estimate I		168	7/1/01
SMUD McClellan Upgrade		22	7/1/01
Cal-ISO Peaking Facilities		500	7/1/01
Huntington Beach Modern.		450	7/1/01
West Phoenix (Phase 1)	CCCT	120	8/1/01
Sunrise Power Phase I	Simple	320	8/1/01
LADWP CT Projects		300	8/1/01
United Golden Gate Peaking	Combustion	51	8/1/01
La Paloma Phase I	CCCT	521	11/1/01
CEC Renewables Estimate II		510	12/31/01
TOTAL FOR FY 01		**5,621**	
FY 02			
Kyrene (Oasis)	CCCT	250	2/1/02
La Paloma Phase II	CCCT	522	3/1/02
Sundance Energy Project		600	6/1/02
Moss Landing	CCCT	1060	6/1/02
Redhawk 1	CCCT	530	7/1/02
Redhawk 2	CCCT	530	7/1/02
Delta Energy Center	CCCT	880	7/1/02
Arlington Valley		550	8/1/02
Caithness Big Sandy (Phase I)	CCCT	500	11/1/02
Gila River	CCCT	2000	12/1/02
TOTAL FOR FY 02		**7,422**	
FY 03			
Pastoria	CCCT	750	1/1/03
Pastoria 2	CCCT	250	1/1/03
Redondo Beach		700	1/1/03
Three Mountain	CCCT	500	2/1/03
Hanford Energy Park	CCCT	99	2/1/03
Mesquite Power		1000	3/1/03
Elk Hills	CCCT	500	3/1/03
Metcalf Energy Center	CCCT	600	3/1/03
Midway-Sunset	CCCT	500	3/1/03
Blythe	CCCT	520	4/1/03
Mountainview		1056	5/1/03

Contra Costa	CCCT	530	5/1/03
West Phoenix (Phase 2)	CCCT	500	6/1/03
Otay Mesa	CCCT	510	6/1/03
High Desert	CCCT	720	7/1/03
Sunrise Power Phase II	CCCT	240	8/1/03
Harquahala Generating Station	CCCT	1040	9/1/03
Potrero	Combustion	540	9/1/03
Morro Bay	CCCT	1200	10/1/03
Fourmile Hill		50	12/1/03
Teayawa Energy Center		600	12/1/03
Valley	CCCT	250	12/1/03
TOTAL FOR FY 03		**12,655**	
FY 04			
Antelope	CCCT	1000	2/1/04
Caithness Big Sandy (Phase II)	CCCT	220	3/1/04
Rio Linda/Elverta	CCCT	560	4/1/04
South City	CCCT	550	4/1/04
Gila Bend	CCCT	750	6/1/04
East Altamont		1100	6/1/04
United Golden Gate CC	CCCT	520	6/1/04
Magnolia Modernization		310	6/1/04
El Segundo		280	7/1/04
Roseville		750	7/1/04
SMUD CCCT Cycle	CCCT	1000	7/1/04
Maxwell		600	7/1/04
Russell City Energy Center	CCCT	600	10/1/04
Springerville Generation I		380	12/1/04
Long Beach District		500	12/1/04
TOTAL FOR FY 04		**9,120**	
FY 05			
La Paz	CCCT	1080	8/1/05
Santan	CCCT	825	12/1/05
Springerville Generation II		380	12/1/05
TOTAL FOR FY 05		**2,285**	
FY 06			
Redhawk 3	CCCT	530	6/1/06
TOTAL FOR FY 06		**530**	
FY 07			
White Tank Mountain	Pump Storage	1250	1/1/07
Toltec Power Station		2000	1/1/07
Mobile		600	1/1/07
Redhawk 4	CCCT	530	12/1/07
TOTAL FOR FY 07		**4,380**	