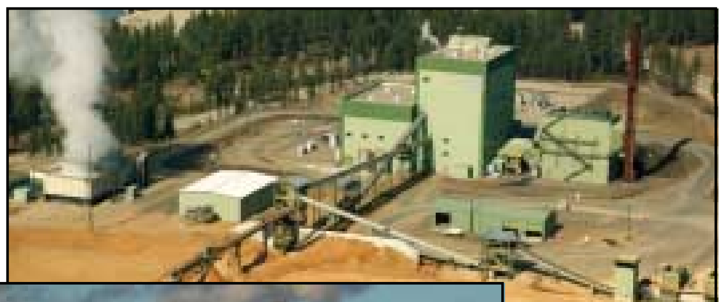
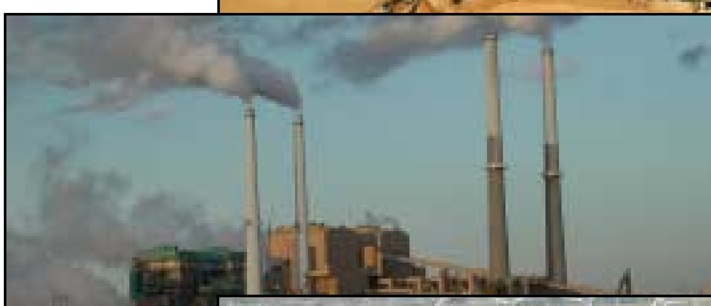
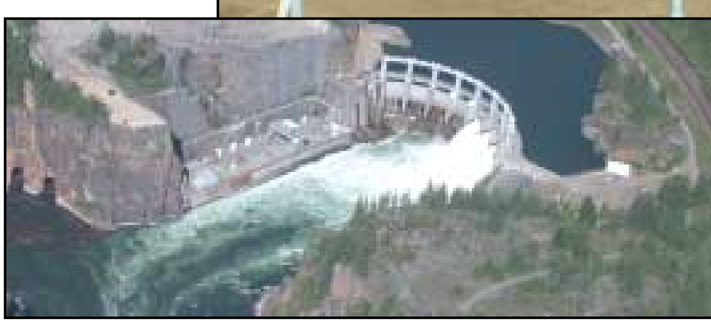
AVISTA®

Corp.







2003 IRP Technical Appendices

Table of Appendices

Appendix

A

Resource & Contract Details

Utility-Owned Resources

The Company owns and operates hydroelectric projects on both the Spokane and Clark Fork Rivers. It owns a portion of two coal-fired units located in Montana and operates three natural gas-fired projects within its service territory. The Company has a 50 percent share in a new gas-fired project located in Oregon. Finally, the Company owns and operates a large wood waste generating plant near Kettle Falls, Washington. These resources are described in further detail below.

Spokane River

The Company owns and operates six hydroelectric dams on the Spokane River. FERC licenses for the projects expire on July 31, 2007 (except for Little Falls, which is licensed by the state of Washington). A short description of each Spokane River project is provided below.

- *Monroe Street*

  Monroe Street was the Company's first generating plant, built on the Spokane River in Spokane in 1890. The plant was rebuilt in 1992 and presently has a maximum capacity of 15,000 kW and a nameplate of 14,800 kW for its single unit.

- *Post Falls*

  Post Falls, completed in 1906 in Post Falls, Idaho; was the Company's second hydroelectric plant. The original plant consisted of five units with a sixth added on December 16, 1980. The plant presently has a maximum capacity of 18,000 kW and a nameplate rating of 14,750 kW.

- *Nine Mile*

  Nine Mile, located near Nine Mile Falls, Washington; was built in 1908 by a private developer. The Company acquired the project in 1925. The four units at the facility have a combined maximum capacity of 24,500 kW and nameplate rating of 26,400 kW.

- *Little Falls*

  Little Falls was completed in 1910. Located on the Spokane River near Ford, Washington; the project has four units that total to a maximum capacity of 36,000 kW and a nameplate rating of 32,000 kW.

- *Long Lake*

  Long Lake, located just above Little Falls, was built in 1915. New runners were installed in 1999, increasing the total maximum capacity of its four units to 88,000 kW and a nameplate rating of 70,000 kW.

- *Upper Falls*

  Upper Falls is located in Spokane, and was completed in 1922. Its single unit has a maximum capacity of 10,200 kW and a nameplate rating of 10,000 kW.

Clark Fork River

The Clark Fork River Project consists of two large hydroelectric projects located in Clark Fork, Idaho, and Noxon, Montana. The two plants operate under a recently renewed FERC license that expires on March 1, 2046.

- *Cabinet Gorge*

  Cabinet Gorge began generating electricity for the Company in 1952. Two additional units were added in 1953, bringing the total to four. Two of the units have since been upgraded, increasing the maximum capacity of the plant to 246,000 kW and the nameplate rating to 245,100 kW.

- *Noxon Rapids*

  Noxon Rapids consists of four hydro units installed between September of 1959 and April of 1960. A fifth unit was installed in December of 1977. The plant presently has a maximum capacity of 527,000 kW and a nameplate rating of 466,200 kW.

Colstrip

Colstrip, located near Colstrip, Montana consists of four coal-fired steam plants. A consortium of utilities owns the project, which is operated by PPL Global. The Company owns fifteen-percent of Units 3 and 4. Unit 3 was completed in January 1984 and Unit 4 in April 1986. The Company's share of each Colstrip unit has a maximum capacity of 111,000 kW with a nameplate rating of 116,700 kW.

Rathdrum

Rathdrum is a two-unit simple-cycle gas-fired plant located near Rathdrum, Idaho; built in 1995. The plant has a maximum capacity of 176,000 kW and a nameplate rating of 166,500 kW.

Northeast

Constructed in late 1978, Northeast is a two-unit aero-derivative simple-cycle plant located in Spokane. The plant has bi-fuel capability and may burn either natural gas or fuel oil. The two generators have a combined maximum capacity of 66,800 kW and a nameplate rating of 61,800 kW.

Boulder Park

Boulder Park, located in Spokane Valley, became operational on August 1, 2002. The site has six internal combustion engines fired by natural gas. The maximum capacity and nameplate rating are 24,600 kW.

Coyote Springs 2

Coyote Springs 2 is a natural gas-fired combined-cycle combustion turbine located near Boardman, Oregon. The Company's 50 percent share equals a maximum capacity of 143,500 kW. The plant is expected to be operational in 2003.

Kettle Falls

The Kettle Falls project began operation in December 1983. The steam plant is fueled by hog fuel. It has a maximum capacity of 50,000 kW and a nameplate rating of 46,000 kW. It is located near Kettle Falls, Washington.

Kettle Falls CT

The Kettle Falls CT is a natural gas-fired combustion turbine that entered commercial service on May 31, 2002. It has a maximum capacity rating of 6,870 kW. Exhaust heat from the plant is routed through a heat recovery boiler. The steam output is then used to increase the efficiency of Kettle Falls.

Power Purchase and Sale Contracts

The Company is currently involved in several medium- to long-term power supply purchase and sale arrangements. This section provides a brief description of the various contracts in effect during the IRP timeframe. For more detailed contract information, provided on a monthly basis over the IRP timeframe, refer to Appendix F.

Bonneville Power Administration – Residential Exchange

The Company entered into a settlement agreement of the Residential Exchange Program that became effective on October 1, 2001. Over the first five-year period of the ten-year settlement the Company is receiving financial benefits intended to be the equivalent of purchasing 90 aMW at Bonneville's lowest cost-based rates. For the subsequent five-year period (beginning October 1, 2006) the Company's benefit level increases to 149 aMW. At Bonneville's option, the 149 aMW may be provided in whole or in part as financial benefits or as a physical power sale.

Bonneville Power Administration – WNP-3 Settlement

On September 17, 1985 the Company signed settlement agreements with BPA and Energy Northwest (formerly the Washington Public Power Supply System), ending its construction delay claims against both parties. The settlement provides for an exchange of energy, an agreement to reimburse the Company for certain WNP No. 3 preservation costs, and an irrevocable offer of WNP No. 3 capability for acquisition under the Regional Power Act.

The energy exchange portion of the settlement contains two basic provisions. The first provides the Company with approximately 42 aMW from BPA through 2019, subject to a contract minimum of 5.8 million MWh. The Company is obligated to pay BPA operating and maintenance costs associated with the energy exchange, determined by a formula in an amount not less than $16 per MWh or more than $29 per MWh, expressed in 1987 dollars.

The second provision of the exchange provides BPA approximately 36 aMW of return energy at a cost equal to the actual operating cost of the Company's highest-cost resource. A further discussion of this obligation, and how the Company plans to account for it, is covered under Planning Reserves below.

Mid-Columbia Contracts

During the 1950s and 1960s, various public utility districts (PUDs) in Central Washington began developing hydroelectric sites on the Columbia River. Each of these plants was very large when compared to the loads then served by the PUDs. To assist in financing these large plants, and to ensure a market for the surplus power, long-term contracts were signed with other public, municipal, and investor-owned utilities in the Northwest.

The Company entered into long-term contracts for the output from four of these projects "at cost." The contracts provide not only for electrical energy, but also for capacity and reserve capabilities. The contracts today provide approximately 190 MW of capacity and 100 aMW of average annual energy. Over the next twenty years, the Wells and Rocky Reach the contracts will expire. While the Company may be able to extend these contracts, it has no assurance today that extensions will be offered. The 2003 IRP therefore does not include energy or capacity beyond their expirations.

The Company was successful in renewing its contract with Grant PUD for power from the Priest Rapids project. The new contract term will be equal to the license term issued by FERC and will cover both the Priest Rapids and Wanapum dams. The license term is expected to be between 30 and 50 years. As part of the all-party settlement over Priest Rapids, the Company acquired an additional quantity of displacement power. Displacement power, available through September 30, 2011, is project output available due to displacement resources being used to serve Grant PUD's load,

A description of the Mid-Columbia contracts is presented in the following table.

Table A.1
Mid-Columbia Contract Quantities Summary

		2004		2009		2014		2019		2023	
Project	**Expires**	**MW**	**aMW**	**MW**	**aMW**	**MW**	**aMW**	**MW**	**aMW**	**MW**	**aMW**
Rocky Reach	10/31/11	37.7	20.5	37.7	20.5	0.0	0.0	0.0	0.0	0.0	0.0
Wells	08/31/18	28.6	9.9	28.6	9.9	28.6	9.9	0.0	0.0	0.0	0.0
Priest Rapids[1]	N/A	129.3	71.0	84.9	46.6	35.0	19.2	24.6	13.5	15.7	8.6
Total		195.6	101.5	151.2	74.0	63.6	29.1	24.6	13.5	15.7	8.6

PacifiCorp Exchange

The Company and PacifiCorp entered into a fifteen-year, 50 MW exchange contract that expires on March 31, 2004. The delivery obligation of the contract will be completed in 2003, and the Company has rights for 17,200 MWh of energy to be delivered prior to contract expiration.

Medium-Term Market Purchases

The Company has purchased 100 MW of flat (7x24) power for the period 2004 through 2010. These purchases were completed during 2001 and 2002.

Nichols Pumping Station

The Company provides energy at Colstrip to operate its share of the Nichols Pumping Station, which supplies water for the Colstrip plant. The Company's share of the Nichols Pumping Station load is approximately one aMW.

Portland General Electric

The Company provides PGE 150 MW of firm capacity under a contract expiring December 31, 2016. PGE may schedule deliveries up to its capacity limit during any ten hours of each weekday. Within 168 hours PGE returns all energy delivered under the contract.

[1] This includes the existing contracts for Priest Rapids and Wanapum, which expire in 2005 and 2009, respectively. Thereafter, the contracts are combined as the Priest Rapids Project (PRP).

Appendix

B

Retail Load Forecast

Economic Growth

A significant regional trend over the past 20 years has been the shift from an economy largely based on natural resource-based manufacturing to one based on light manufacturing and services. The decline in manufacturing employment has been driven by, among other factors, the depletion of mining reserves and timber harvests. These factors have led to the closure of several mines and sawmills throughout the region, and have had a significant impact on the forecast of retail loads.

The Company purchases employment and population forecasts from Global Insight, Inc. (formerly Data Resources, Inc.) for the following three counties, which comprise over 80 percent of the service territory:

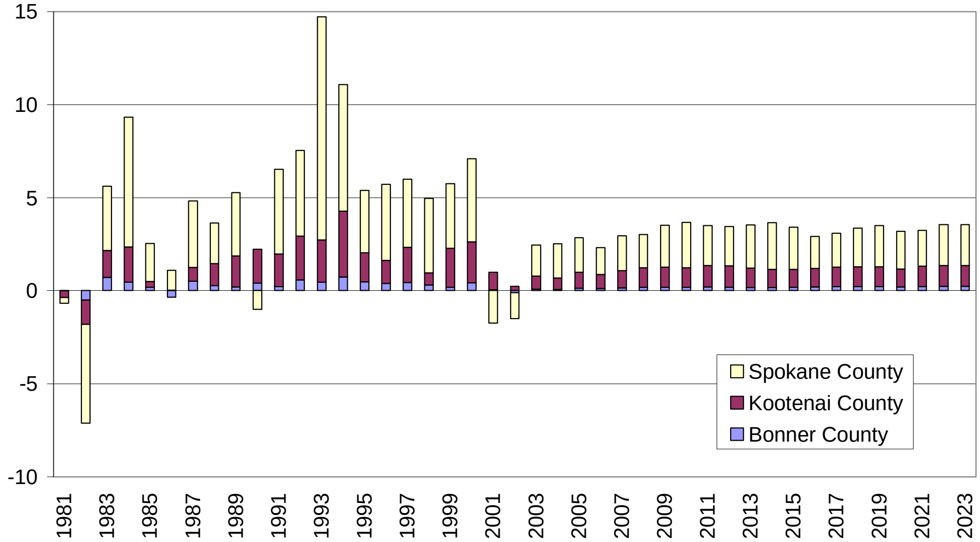
- Spokane County, Washington
- Kootenai County, Idaho
- Bonner County, Idaho

These forecasts are the basis for the Company's electric customer forecasts. The national forecast, from which these regional forecasts are based, was prepared in March 2002. The county-level estimates were completed in May 2002. With regard to growth in the Company's primary counties, the following characterizations can be made:

- Spokane County is expected to exhibit moderate, steady growth for the next twenty years.
- Kootenai County, which is the third-fasted growing county in the U.S., is expected to continue growing rapidly going forward.
- Bonner County is expected to have modest growth, although the other counties dwarf it in size.

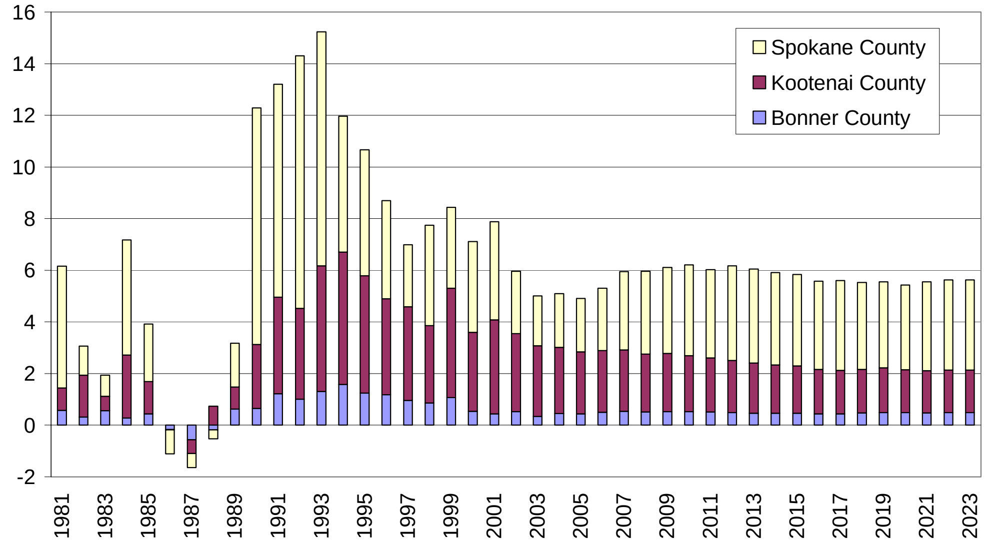
The following chart depicts historic and forecast growth patterns for employment in the above listed counties.

Chart B.1
County Employment Growth Forecast (thousands)



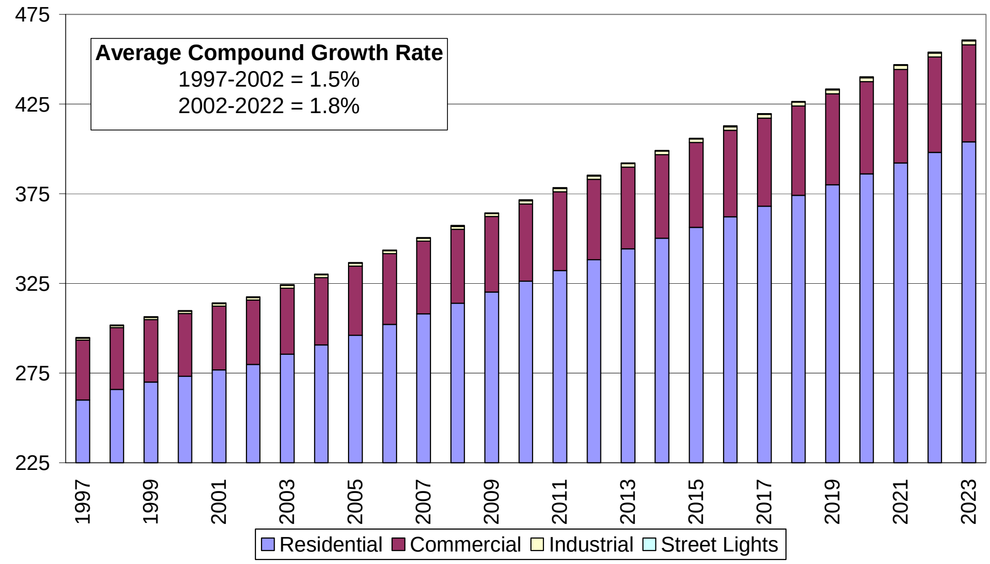
Population growth is the key component of forecasting customer growth. Though there is not a perfect correlation, population provides the fundamental demand for housing. Over the last several years, the region has seen considerable absorption of a housing surplus that was generated after the population boom of the early 1990's. Favorable low interest rates during 2002 sparked a 26.5 percent annual increase in residential permits in Spokane and Kootenai Counties, with many of those homes being connected to the Company's system. The following chart depicts historic and forecast population growth patterns in the above listed counties.

Chart B.2
County Population Growth Forecast (thousands)



Housing is also the fundamental driver of commercial customer expansion, as more retail stores, schools, and other "population-serving" business are attracted to these new markets. Over the twenty-year horizon, customer growth is estimated to average 1.8 percent per year, slightly higher than the 1.5 percent experienced over the past five years. The following chart shows the Company's customer forecast.

Chart B.3
Customer Forecast (thousands)

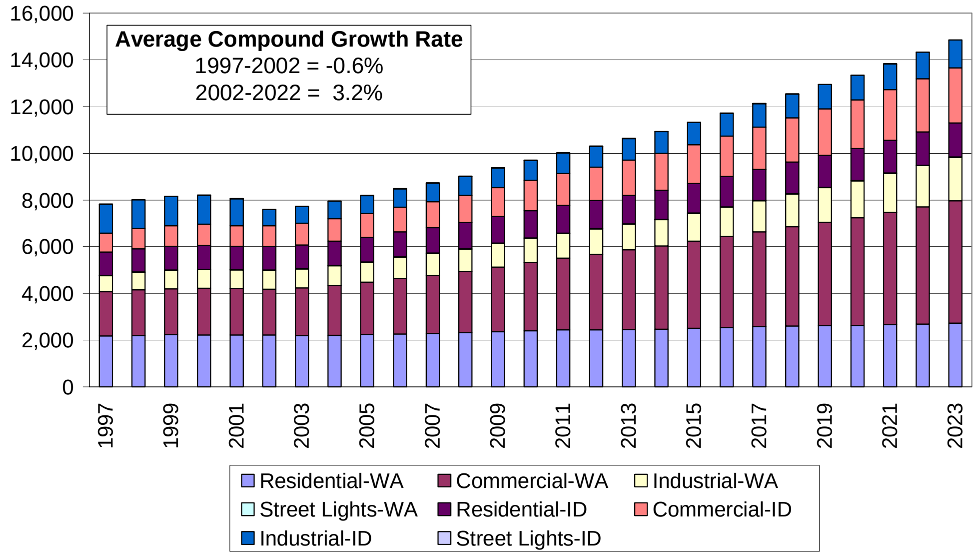


Electric Retail Sales

The energy crisis of 2001 included the implementation of widespread conservation efforts by our customers. In 2002, higher retail electric prices reinforced customer conservation efforts modestly. Due to the economic recession during 2001 and 2002, several large industrial facilities served by the Company were permanently closed, including a major employer in the aluminum industry. The forecast includes what the Company believes to be a conservative assumption—these closures will be permanent. If these facilities are purchased by new operators or restarted by existing owners, the forecast will need to be adjusted.

The twenty-year forecast assumes no additional plant closures, relative stable future retail electric prices that increase slightly below the prevailing rate of inflation, and a modestly healthy economy. Conservation acquisitions are expected to continue throughout the forecast horizon and energy efficient equipment will be installed in new construction and replace retired equipment in residences and businesses. Refer to the following chart for a depiction of the retail electric sales forecast through 2023, as well as actual sales for 1997 to 2002.

Chart B.4
Annual Retail Electric Sales
1997-2023 (in GWh)



NOTE: 1997-2002 are based on actual retail sales (not weather adjusted).

DSM in the Forecast

The system forecast used in the IRP process is the Company's expectation of the aggregate demand at the customer meter. Since DSM resource acquisition impacts the metered demand of our customers, this resource is implicitly incorporated within the forecast.

The Company can very accurately identify and separate the impact of "programmic" DSM within the forecast. Programmic DSM would include efficiency measures that the utility is directly involved in, usually those involving cash incentives grants to the customer. The Company can then disaggregate programmic DSM from the remainder of the forecast and represent that impact as a separate line item within the IRP.

The Company's DSM programs do influence usage beyond that which can be immediately identified through customer program participation. This includes our participation in regional market transformation efforts, local technology transformations, research and development activities, and general market impacts. These influences are difficult to identify and will consequently not be disaggregated from the overall forecast. Thus to some extent there will continue to be some DSM within the forecast.

Energy Load and Peak Load Forecasts

The retail sales forecast detailed above is converted into monthly energy and peak load forecasts. The peak load forecast is the expected (or average) peak demand during the respective month. Depending on weather variation, we would expect actual peak loads to exceed this estimate 50 percent of the time.

Enhancements to Forecasting Process

Consistent with the Company's two-year action plan, the forecasting models have been updated with the latest energy consumption profiles. An additional enhancement was made with the inclusion of cooling degree-days. In previous years, attempts were made to include hot weather impacts on summertime loads, but they were unsuccessful. Our customers appear to have met a threshold for usage during the air-conditioning season. The model coefficients were checked for price elasticity impacts, and the new values were incorporated into the forecast; they have not changed greatly during the last twenty years.

Appendix

C Modeling Details

Selection of the AURORA Model

In the past, the Company has utilized PROSYM, an hourly dispatching program developed by Henwood Energy Services for intra-month resource dispatch analyses. The Company's first official use of PROSYM was in support of the Clark Fork River relicensing effort in 1994. PROSYM was also used in the Company's 2001 General Rate Case in Washington. PROSYM is a resource dispatch program that relies upon inputs including retail loads, fuel prices, and wholesale electricity prices.

In late 2001, the Company decided to take a significant step forward in resource modeling and elected to obtain a new chronological dispatch model with the ability to provide an electric market price forecast based on marketplace fundamentals. To this end the Company reviewed products offered by several leading purveyors of such tools.

Early in the process, the Company determined that five basic capabilities were necessary:

1. *GUI and Usability*
   Each of the evaluated models relies upon a very large database containing all of the generation facilities, utility loads, fuel prices, and other details pertaining to the Western Electricity Coordinating Council (WECC). A graphical user interface (GUI) provides a much more efficient means to work with these large data sets.

2. *Deterministic*
   The deterministic capability of a model is signified by its ability to accurately represent resource capabilities and loads. For example, certain models are able only to allow one heat rate and capacity output for a given plant. Other models were not chronological and therefore had the potential to violate the minimum up and down requirements of some base load resources and dispatch them on an hourly basis.

3. *Scenarios*
   IRPs and other regular analyses performed by the Company necessitate the ability for developing scenarios. All of the evaluated models had some means whereby scenarios could be managed.

4. *Stochastic*
   Recent events, where market prices for natural gas and electricity have risen to points many times above their historical levels, have emphasized the necessity of being able to evaluate the risks inherent in any resource strategy.

5. *Capacity Expansion*
   Over time the west coast will require a growing pool of new resources. The ideal model was to include the capability to serve regional load growth by selecting least-cost resource alternatives from a list of hypothetical future generation facilities.

AURORA, by EPIS Inc., best met the Company's criteria. In April of 2002, Company staff, along with staff from the Idaho and Washington Commissions, began training on AURORA at EPIS headquarters in West Linn, Oregon. Evaluation and testing of AURORA continued throughout the summer of 2002. The Company also provided its state regulators with licenses to operate AURORA later in that year.

Cost of Capital for New Resources

An important assumption underlying AURORA that was not detailed in *Section 5* is the cost of capital for new resources. Depending on who backs the financing of new generation resources, capital carrying costs vary. Generally, independent power producers (IPPs) have higher capital carrying costs reflective of their riskier position in the marketplace. IPPs do not benefit, as utilities do, from an allowed rate of return on their investments. As a result, utilities generally have lower capital carrying costs. The following table provides the assumed cost of capital as input into AURORA.

Table C.1
AURORA Cost of Capital

	Municipal	IOU	IPP	Weighted
Participation	20.0%	60.0%	20.0%	
Debt Cost (After-Tax)	6.5%	5.4%	5.7%	5.7%
Debt Finance Level	100.0%	50.0%	60.0%	62.0%
Cost of Equity	N/A	10.0%	16.0%	9.2%
Weighted Cost of Capital	6.5%	8.2%	10.2%	10.0%
Weighted Average After-Tax Cost of Capital				7.0%

The weighted average after-tax cost of capital in AURORA was assumed to be seven percent based on municipal utilities, investor owned utilities (IOUs), and IPPs constructing twenty, 60, and twenty percent of the future resource additions, respectively.

Portfolio Optimization Using Linear Programming (LP) Module

One of the major challenges of the planning process is selecting an optimal portfolio of resource alternatives. Portfolio optimization for the 2003 IRP is developed using a Linear Programming Module that selects the optimal level of options and the specific timing of each option. For example, over a twenty-year horizon the optimal set of resources to meet a given set of future load requirements might be a combination of a new combustion turbine and a coal plant. The LP Module is capable of assisting in the selection of the best mix of resources, and the specific timing (i.e., year of installation) of each new resource.

As a further step, the LP Module is capable of comparing the optimal solution to other alternatives that decision-makers might consider better for more qualitative reasons (e.g., wind integration). This capability proved valuable given that a range of portfolios was found to provide a similar lowest cost solution. The LP Module is also capable of adjusting the optimal decision based on specific attributes such as lowest cost, level of risk, impact on the environmental, etc. Finally, the LP Module can ensure a specific minimum or maximum level of future resources generating capability is met (e.g., renewable portfolio standards).

Inputs to LP Module

The LP Module is dependent on various information derived from AURORA, and assumed fixed costs associated with each portfolio decision. For each Monte Carlo iteration, AURORA records three key statistics: the operating margin of the Company's existing generation portfolio assuming no incremental changes occur; the cost of serving its retail load assuming it was met entirely from the wholesale marketplace; and the operating margin of the various new resource alternatives. This data is then summed by calendar year and input into the LP Module.

In addition to AURORA output, the LP Module considers the annual fixed-cost payment stream associated with each incremental resource decision. For example, fixed costs for a new CCCT include not only capital, but also such items as fixed O&M, transmission integration, depreciation, taxes, and miscellaneous charges.

The LP Module reviews the benefit derived from each new resource and then optimizes the selection of resources given a level of future requirements. Where a new resource is selected its operating margin, as determined by AURORA, is combined with its associated fixed costs to derive the expected net impact to the Company.

Linear Programming Theory - by Robert Fourer

A Linear Program (LP) is a problem that can be expressed as follows (the so-called Standard Form):

Minimize cx
subject to Ax = b
x >= 0

where x is the vector of variables to be solved for, A is a matrix of known coefficients, and c and b are vectors of known coefficients. The expression "cx" is called the objective function, and the equations "Ax=b" are called the constraints. All these entities must have consistent dimensions, of course, and you can add "transpose" symbols to taste. The matrix A is generally not square, hence you don't solve an LP by just inverting A. Usually A has more columns than rows, and Ax=b is therefore quite likely to be under-determined, leaving great latitude in the choice of x with which to minimize cx.

The word "Programming" is used here in the sense of "planning"; the necessary relationship to computer programming was incidental to the choice of name. Hence the phrase "LP program" to refer to a piece of software is not a redundancy, although I tend to use the term "code" instead of "program" to avoid the possible ambiguity.

Although all linear programs can be put into the Standard Form, in practice it may not be necessary to do so. For example, although the Standard Form requires all variables to be non-negative, most good LP software allows general bounds l <= x <= u, where l and u are vectors of known lower and upper bounds. Individual elements of these bounds vectors can even be infinity and/or minus-infinity. This allows a variable to be without an explicit upper or lower bound, although of course the constraints in the A-matrix will need to put implied limits on the variable or else the problem may have no finite solution. Similarly, good software allows b1 <= Ax <= b2 for arbitrary b1, b2; the user need not hide inequality constraints by the inclusion of explicit "slack" variables, nor write Ax >= b1 and Ax <= b2 as two separate constraints. Also, LP software can handle maximization problems just as easily as minimization (in effect, the vector c is just multiplied by -1).

The importance of linear programming derives in part from its many applications (see further below) and in part from the existence of good general-purpose techniques for finding optimal solutions. These techniques take as input only an LP in the above Standard Form, and determine a solution without reference to any information concerning the LP's origins or special structure. They are fast and reliable over a substantial range of problem sizes and applications.

Two families of solution techniques are in wide use today. Both visit a progressively improving series of trial solutions, until a solution is reached that satisfies the conditions for an optimum. Simplex methods, introduced by Dantzig about 50 years ago, visit "basic" solutions computed by fixing enough of the variables at their bounds to reduce the constraints Ax = b to a square system, which can be solved for unique values of the remaining variables. Basic solutions represent extreme boundary points of the feasible region defined by Ax = b, x >= 0, and the simplex method can be viewed as moving from one such point to another along the edges of the boundary. Barrier or interior-point methods, by contrast, visit points within the interior of the feasible region. These methods derive from techniques for nonlinear programming that were developed and popularized in the 1960s by Fiacco and McCormick, but their application to linear programming dates back only to Karmarkar's innovative analysis in 1984.

The related problem of integer programming (or integer linear programming, strictly speaking) requires some or all of the variables to take integer (whole number) values. Integer programs (IPs) often have the advantage of being more realistic than LPs, but the disadvantage of being much harder to solve. The most widely used general-purpose techniques for solving IPs use the solutions to a series of LPs to manage the search for integer solutions and to prove optimality. Thus most IP software is built upon LP software, and this FAQ applies to problems of both kinds.

Linear and integer programming have proved valuable for modeling many and diverse types of problems in planning, routing, scheduling, assignment, and design. Industries that make use of LP and its extensions include transportation, energy, telecommunications, and manufacturing of many kinds. A sampling of applications can be found in many LP textbooks, in books on LP modeling systems, and among the application cases in the journal Interfaces.

Source: Robert Fourer (4er@iems.nwu.edu), "Linear Programming Frequently Asked Questions," Optimization Technology Center of Northwestern University and Argonne National Laboratory, http://www-unix.mcs.anl.gov/otc/Guide/faq/ linear-programming-faq.html (2000).

Capacity Expansion

AURORA simulates the entire WECC and develops an hourly price forecast based on user inputs. One sophisticated feature of AURORA is its ability to add new resources in a least-cost manner to serve load growth over time, referred to as "capacity expansion." AURORA develops the capacity expansion plan using a list of user-defined new resources, detailed further in *Section 4*. Older, less-efficient units are retired and new resources are added through an iterative process that identifies the optimal least-cost mix through the term of the study. Once the capacity expansion plan is complete, hourly market prices can be estimated. The Company included a $250 (in 2004 dollars) electricity price cap over the study period, which is intended to represent the continuation of price caps imposed by FERC.

The overwhelming resource preference of the capacity expansion exercise is combined-cycle combustion turbines (CCCTs). This result is consistent across the WECC. Wind plants are the second-most selected alternative, accounting for nearly seventeen percent of installed capacity by the end of the twenty-year study. Modest amounts of coal, and simple-cycle combustion turbines (SCCTs) are also selected. The following table illustrates the resource retirements and additions over various years of the IRP study. More detailed results from the study may be found in *Appendix J*.

Table C.2
Cumulative IRP Capacity Expansion Resource Summary (GW)

Year	CCCT	Coal	SCCT	Wind	Retire	Net
2004	0.00	0.00	0.00	0.00	(0.50)	(0.50)
2008	0.28	0.00	0.00	1.10	(7.48)	(6.09)
2013	16.06	2.00	0.00	11.10	(25.74)	3.43
2018	40.70	2.00	0.09	13.90	(25.81)	30.90
2023	67.30	2.00	0.83	14.00	(25.81)	58.34
	80.0%	2.4%	1.0%	16.6%		

Overall, AURORA selects 67.3 GW of new CCCT generation capacity. This equates to 80 percent of the total. Nearly 26 GW of older resources are retired over the term of the study, with a majority leaving service by 2013. Most of the resource retirements are older, inefficient natural gas- and oil-fired plants. A list of specific plants retired in the capacity expansion run may be found in *Appendix J*.

EPIS, the developers of AURORA, provided the Company with a detailed document regarding the capacity expansion process. This document has been included as *Appendix I*.

Modeling Process Diagram

Figure C.1 depicts the entire modeling process. This process utilized three spreadsheet-based models, as well as AURORA, to develop, execute, and evaluate 200 distinct iterations of Monte Carlo simulation.

The process represented in *Figure C.1* includes the following stages of analysis:

1. *Stochastic Analysis*
   The initial stage was dedicated to the development of inputs for AURORA that incorporate varying natural gas prices, WECC loads, and northwest hydroelectric generation. It utilized a spreadsheet-based model to generate 200 distinct input data sets based on random variables, and upload each data set to an Oracle database.

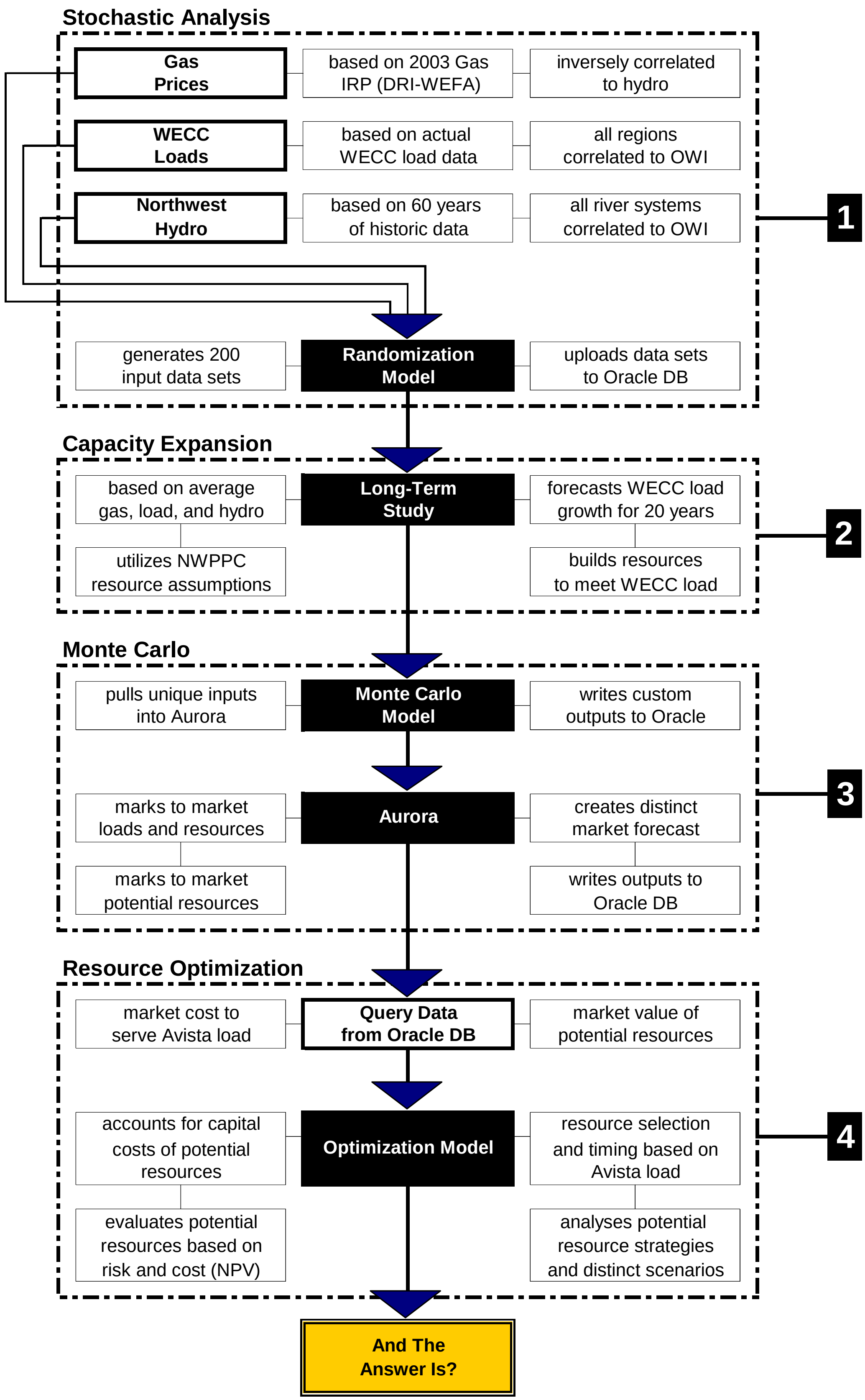
2. *Capacity Expansion*
   The second stage in the process was capacity expansion, where AURORA matched twenty years of WECC load growth with the construction of hypothetical new generation. Capacity expansion utilized average values for natural gas prices, WECC loads, and northwest hydroelectric generation; as well as resource assumptions from the NWPPC.

3. *Monte Carlo*
   The next stage incorporated the results of the stochastic analysis and capacity expansion. It used a spreadsheet-based model to select a specific input data set, run AURORA, and write the outputs to an Oracle database. This process was repeated for each of the 200 iterations, and resulted in 200 distinct output data sets.

4. *Resource Optimization*

The final stage made use of a spreadsheet-based optimization model that incorporated an LP Module to select an optimum set of resources based on Company-specific needs. This stage evaluated numerous resource strategies under several distinct scenarios to develop and assess the *Preferred Resource Strategy*.

Figure C.1
Modeling Process Diagram



Appendix

D Risk Details

Resource Risk Profiles

There are many risk factors that must be considered when evaluating prospective new resources. The most significant risk factors associated with different resources are detailed below.

Fuel Supply Risk

Some resources do not have consistent access to fuel. The best example of this may be hydro, where fuel is determined by precipitation and runoff. As a result, fuel availability can vary significantly from year to year. Fuel supply risk can be substantial, particularly when the fuel is essentially free or very low cost, as is the case with hydro. When evaluated on an hourly or daily basis, wind resources cannot be counted on to have any fuel supply. Long-term market purchases have fuel supply risk due to reduced assurance that the supplier will exist to perform over the contract term.

Fuel Price Risk

Resources that don't have long-term fixed price fuel contracts often have significant fuel cost risk. Natural gas-fired resources have the most fuel price risk, since the gas price can be volatile and is typically not fixed over a long period. Coal resources typically have a fixed price long-term supply contract with little fuel price risk. Hydro and wind resources have free fuel, so there is no fuel price risk.

Forced Outage Risk

Forced outage rates vary between resources. Resources with low operating costs present the most risk from forced outages. While hydro and wind plants generally have very low forced outage rates, coal plants have the highest forced outage rates. Forced outage risk can be significant with coal plants because the operating cost is usually low and outages, while usually short, can be much longer. Longer-term (several month) outages at a coal plant can have a significant impact on power supply costs. Forced outages at natural gas fired plants do not represent as large of a risk because the operating cost is typically high, so purchasing replacement power may not constitute a large incremental expense.

Environmental Risk

All resources contain some environmental risk. Regulation, licensing, and permitting conditions may change over time and adversely impact the cost of a resource. Examples of environmental risk include potential future carbon tax on fossil fuel-fired resources, permitting and construction delay risks for most resources, and relicensing issues with hydroelectric facilities.

Resource Characteristics

Each type of resource has its own unique characteristics. Included below are the prominent resource types and corresponding characteristics.

Combustion Turbines

Short-term dispatch capability reduces risk in that the Company can shut down a plant when its costs are higher than equivalent market purchases. High fuel cost that is correlated to electric prices increases risk. Low capital cost reduces present value cost and initial rate pressure.

Coal

Low fuel cost that is typically not correlated to electric prices is good for risk mitigation. High capital cost increases present value cost and initial rate pressure. Construction and environmental risks may be significant, but are hard to quantify.

Wind

Very low operating cost and output that is not correlated to electric prices is good for risk mitigation. High capital cost increases present value cost and initial rate pressure. There are significant concerns with system integration (i.e., control area services). Wind would be beneficial if renewable portfolio requirements were adopted. It also appears to have significant public appeal.

Market Purchases

The Company is always in the market, balancing loads and resources on an hourly, daily, monthly, and quarterly basis. The Company also, on occasion, makes medium-term (up to five year) purchases when prices appear to be lower than marketplace fundamentals. Short-term purchases (one year or less) can be low cost in surplus market conditions, but come with higher risk.

Utilizing medium-term purchases can be a low cost strategy when markets are favorable, but can have somewhat higher risk due to counter party credit issues and the need to roll the contracts over in potentially high-cost market conditions. Long-term (beyond five year) fixed price purchases are good for risk mitigation to the extent the counter party exists into the future to make deliveries. However, the risk associated with issues including credit, margin calls, and supplier reliability generally increases as the term extends. The current lack of market liquidity makes the execution of even medium term purchases difficult, and makes long-term purchases unlikely.

Cogeneration

Cogeneration resources may provide risk mitigation depending on the fuel source and contractual arrangements. Typically the Company purchases cogeneration under long-term fixed price contracts. In this case cogeneration has the same risk mitigation characteristics as a fixed price market purchase. The purchase is unit contingent so there is also supply risk. Cogeneration is an opportunity resource, meaning that if a host proposes a viable project the Company will consider it. Since the Company does not control the host sites, it is difficult to plan for the addition of cogeneration resources.

Demand-Side Management (DSM)

DSM resources are typically characterized by all capital cost and no operating cost. Because of this they have the risk mitigation properties similar to other high fixed, low variable cost resources. DSM can increase risk in other ways due to the difficulty in verifying energy savings.

The Company has focused its analytical efforts on understanding the impacts of commercially available and relatively low cost demand-side resource options. To this end, only those resources with a reasonable likelihood of benefiting customers were included in the analyses. The benefits and risks expected from these resources, as detailed above, were supported by the analyses performed for the IRP.

Load Correlations

The following table contains load correlations between the WECC load areas modeled in AURORA and OWI (Oregon, Washington, and North Idaho). A load area representing the Company's service territory was also included in the model, but is not included in the table below. This load area (AVA) was assumed to be 100 percent correlated to OWI.

Table D.1
Load Correlations to OWI
(Average of Weekdays)

Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AB	0.659	NotSig	0.481	NotSig	Mix	0.635	0.668	Mix	Mix	0.479	NotSig	NotSig
AZ	0.440	0.664	NotSig	Mix	(0.289)	0.666	NotSig	NotSig	NotSig	NotSig	Mix	NotSig
BC	0.918	0.838	0.825	0.733	0.617	NotSig	0.560	NotSig	0.638	0.809	0.525	0.890
CANo	NotSig	0.734	NotSig	NotSig	NotSig	0.771	Mix	0.757	0.789	NotSig	Mix	NotSig
CASo	NotSig	Mix	NotSig	NotSig	Mix	0.680	Mix	0.500	0.778	NotSig	NotSig	NotSig
CO	0.623	NotSig	0.567	Mix	Mix	NotSig	NotSig	NotSig	NotSig	0.655	0.629	0.571
IDSo	0.673	0.747	0.882	NotSig	NotSig	0.758	Mix	0.789	0.733	0.561	0.587	0.813
MT	0.894	0.773	0.755	0.651	0.405	0.599	0.786	0.648	0.752	NotSig	0.856	0.898
NVNo	Mix	NotSig	NotSig	NotSig	NotSig	NotSig	NotSig	NotSig	NotSig	Mix	0.476	NotSig
NVSo	NotSig	0.641	0.513	Mix	NotSig	0.729	Mix	NotSig	Mix	NotSig	0.461	Mix
NM	0.384	Mix	Mix	NotSig	NotSig	Mix	NotSig	Mix	NotSig	NotSig	Mix	Mix
UT	0.816	NotSig	0.669	0.697	0.610	0.698	0.703	0.604	0.611	NotSig	0.561	0.837
WY	0.765	Mix	0.641	NotSig	Mix	Mix	NotSig	NotSig	0.483	NotSig	0.522	0.633

NOTE: "NotSig" represents that relationship was not statistically significant; "Mix" represents that the relationship was not a consistent across time.

Market Uncertainty

The northwest electricity marketplace has historically been characterized by a general cooperation among participants. Various past and present consortiums of utilities, such as the NWPP, PNUCC, the inter-company pool, stand as a testament to this coordination. Unlike some other parts of the country where a lack of transmission access prevented vibrant wholesale markets, the northwest benefited from a transmission system owned substantially by BPA. This provided a means for utilities to buy and sell electricity as their needs warranted. This type of cooperation remained into the mid-1990s.

Beginning in the mid-1990s, regional cooperation was replaced with competition. Beginning with the Energy Policy Act of 1992, utilities were pushed into wholesale and, later through state deregulation attempts, retail competition. Utilities witnessed the entrance of marketing companies whose primary purpose was not to serve retail customers, but instead was to generate profits from energy trading. Many utilities responded to this competition by spinning off their own unregulated marketing arms. In 1996 the inter-company pool was abandoned and cooperation was restricted significantly due to "competitive interests."

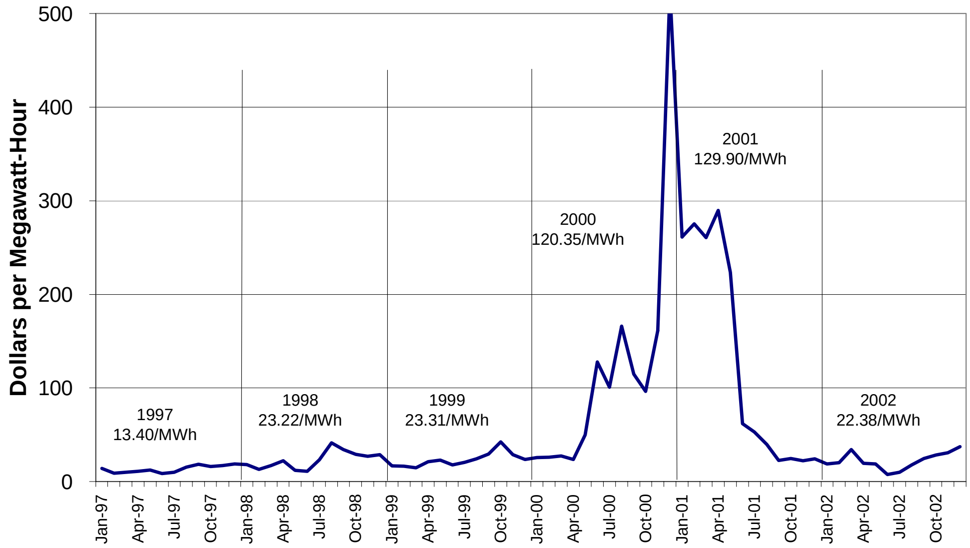
In 1996 California passed Assembly Bill 1890 opening their electricity marketplace to retail competition. The industry was abuzz with excitement. Then-Governor Pete Wilson probably summed up the general consensus of that period by stating as he signed the bill into law, "[that] this landmark legislation is a major step in our efforts to lower rates, provide consumer choice and offer reliable service, so that no one literally is left in the dark." For various reasons the results of AB1890 as implemented could not have been further from expectations.

Adding to marketplace uncertainty was a rapid erosion of the capacity surplus responsible for the more than a decade of low-cost wholesale market prices that helped drive the train of electricity deregulation. Many northwest utilities, including this Company, began to rely on the wholesale marketplace to serve their load requirements. The logic of this strategy was clear at the time and was supported by regulatory bodies through rate cases and IRPs: new resources could not be built except at twice the cost of market purchases.

Federal deregulation efforts, California's deregulation, load growth and the reliance of utilities on the marketplace to serve their retail requirements, the entrance of for-profit marketing entities, and low hydroelectric conditions came together in 2000 to create unprecedented market conditions. Wholesale prices rose from historical levels of twenty dollars per MWh to more than five hundred dollars. Utilities across the West approached or went bankrupt as they purchased power at costs as much as ten times what they were recovering from sales to their customers. Power marketers who also were planning to serve sales obligations from the spot market went out of business. Enron, the largest player in the marketplace and the entity responsible for a majority of market liquidity, declared bankruptcy and stopped trading. Customer rates were increased by tens of percentage points.

By mid-2001 electricity prices returned to historical levels in response to new generation construction and FERC-imposed price caps. The run-up and fall of electricity prices can be seen in the following chart of Mid-C average monthly prices.

Chart D.1
Mid-Columbia Market Prices 1999-2002



Wholesale market prices in 1998 and 1999 averaged $23.19 dollars per MWh. The averages in both 2000 and 2001 were more than $120 per MWh. 2002 averaged $22.38 per MWh, modestly lower than the 2000/01 period.

Liquidity, the essential ability to buy and sell in a competitive marketplace, has always challenged the west coast electricity markets. Until the energy crisis occurred, liquidity was expanding; the number of counter parties the Company could do business with was increasing. This afforded the Company greater opportunities for portfolio optimization. Since the energy crisis, the Company has witnessed a rapid decline in the number of counter parties available to it due to many marketers leaving the industry and the increasingly difficult task of acquiring the credit necessary to do business. However, the risk of price volatility remains. Utility planning must now re-double its efforts to address market price fluctuations such as those witnessed during 2000 and 2001.

Industry Restructuring

Industry restructuring to open the electric wholesale energy market to competition was initially promoted by federal legislation. The Energy Policy Act of 1992 amended provisions of the Public Utility Holding Company Act of 1935 and the Federal Power Act to remove certain barriers to a competitive wholesale market. The Energy Act expanded the authority of the FERC to issue orders requiring electric utilities to transmit power and energy to or for wholesale purchasers and sellers, and to require electric utilities to enlarge or construct additional transmission capacity for the purpose of providing these services. It also created "exempt wholesale generators," a new class of independent power plant owners that are able to sell generation only at the wholesale level. This permits public utilities and other entities to participate through subsidiaries in the development of independent electric generating plants for sales to wholesale customers without being required to register under the PUHCA.

FERC Order No. 888, issued in April 1996, requires public utilities operating under the Federal Power Act to provide access to their transmission systems to third parties pursuant to the terms and conditions of the FERC's pro-forma open access transmission tariff. FERC Order No. 889, the companion rule to Order No. 888, requires public utilities to establish an Open Access Same-Time Information System (OASIS) to provide transmission customers with information about available transmission capacity and other information by electronic means. It also requires each public utility subject to the rule to functionally separate its transmission and wholesale power merchant functions. The FERC issued its initial order accepting the non-rate terms and conditions of the Company's open access transmission tariff in November 1996. The Company filed its "Procedures for Implementing Standards of Conduct under FERC Order No. 889" with the FERC in December 1996 and adopted these Procedures effective January 1997. FERC Orders No. 888 and No. 889 have not had a material effect on the Company's operating results.

The Company is participating with nine other utilities in the western United States in the possible formation of a Regional Transmission Organization (RTO), RTO West, a non-profit organization. The potential formation of RTO West is in response to a FERC order requiring all utilities subject to FERC regulation to file a proposal to form a RTO, or a description of efforts to participate in a RTO, and any existing obstacles to RTO participation. RTO West filed its Stage 2 proposal with the FERC in March 2002 and received limited approval from the FERC of this initial plan in September 2002. Depending on regional support, RTO West could be operational in late 2005 or early 2006.

The Company and two other utilities have also taken steps toward the formation of a for-profit Independent Transmission Company, TransConnect, which would be a member of RTO West, serve portions of five states and own or lease the high voltage transmission facilities of the participating utilities. TransConnect filed its proposal with the FERC in November 2001 and received limited approval from the FERC in September 2002.

The final proposals must be approved by the FERC, the boards of directors of the filing companies and regulators in various states. The companies' decision to move forward with the formation of TransConnect or RTO West will ultimately depend on the conditions related to the formation of the entities, as well as the economics and conditions imposed in the regulatory approval process. If TransConnect were formed, it could result in the Company divesting its electric transmission assets. The formation of RTO West or TransConnect could have an impact on the Company's transmission costs. However, the Company believes that any changes to transmission costs would be reflected as an adjustment to retail rates.

On July 31, 2002, the FERC issued a Notice of Proposed Rulemaking proposing a Standard Market Design (SMD) that would significantly alter the markets for wholesale electricity and transmission and ancillary services in the United States. The new SMD would establish a generation adequacy requirement for "load-serving entities" and a standard platform for the sale of electricity and transmission services. Under the new SMD, Independent Transmission Providers would administer spot markets for wholesale power, ancillary services and transmission congestion rights, and electric utilities, including the Company, would be required to transfer control over transmission facilities to the applicable Independent Transmission

Provider. There have been significant state-level and regional concerns raised with the FERC with respect to the SMD, particularly in the western and southeastern United States. Public meetings were held during the second half of 2002 and early 2003 with an updated SMD expected to be issued during the first half of 2003. Once the final SMD is issued, a phased compliance schedule will begin. The Company is currently in the process of determining the impact the proposed SMD would have on its operations as well as how the SMD would impact the RTO West and TransConnect proposals. The Company is subject to state regulation in each of the states it operates in. State regulatory agencies are actively involved in the SMD rulemaking process.

The North American Electric Reliability Council and the WECC have undertaken initiatives to establish a series of security coordinators to oversee the reliable operation of the regional transmission system. Accordingly, the Company, in cooperation with other utilities in the Pacific Northwest, established the Pacific Northwest Security Coordinator (PNSC), which oversees daily and short-term operations of the Northwest sub-regional transmission grid and has limited authority to direct certain actions of control area operators in the case of a pending transmission system emergency. The Company executed its service agreement with the PNSC in September 1998.

DRAFT

Interoffice Memorandum

Energy Resources

DATE: April 11, 2003

TO: Clint Kalich

FROM: Ed Groce

SUBJECT: SMD Resource Adequacy

The reserve margin and planning horizon sections of FERC's SMD NOPR are summarized below at your request.

- In order to operate a transmission system reliably, adequate generation must be available to meet load. Some lead time is needed to develop adequate infrastructure for the future.

- Resource adequacy must be assessed at the regional level. Because all customers in an interconnected region are interdependent, a shortage of resources for some customers in the region can lead to a shortage for the entire region, which threatens reliable grid operations and risks sustained shortages with attendant high prices for the region.

- A requirement to assure adequate long-term resources is currently needed because spot market prices do not consistently signal the need for new infrastructure in the electric power industry. Most resources take years to develop and spot market prices alone may not signal the need to begin development of new resources in time to avert a shortage.

- Each region should take its own characteristics into account when determining the appropriate level, subject to a minimum level of resource adequacy for all regions. This determination has historically been made by load-serving entities under the oversight of the states, and FERC wants this state oversight to continue. FERC proposes that the level should be set by a Regional State Advisory Committee. States in the region should have this strong role in determining the level of resource adequacy because a higher level provides greater reliability and also incurs higher costs that affect most retail customers. State representatives are in the best position to determine on behalf of retail customers the trade-off between the cost to the customers of extra generation and demand response reserves and the difficult-to-quantify benefits to the customers of increased reliability and reduced exposure of the region to the effects of a power shortage.

- Resource adequacy reserves are often called planning reserves and are not the same as 5 and 7 percent operating reserves.

- Once the future level of supply and demand resources is determined, the region must assess whether this level is adequate. This requires a regional determination of the appropriate level of resources, for example, whether the reserve margin (if reserve margin is the region's measure of resource adequacy) should be 12, 15, 18 percent, or another level.

- FERC is concerned that the requirement be set so that the RTO can operate the system reliably and that inadequate resources could lead to poor market liquidity and even shortages with sustained high wholesale power prices. For these reasons, FERC proposes to adopt a 12 percent reserve margin as a minimum regional level for all regions with the understanding that this is low by traditional generation adequacy standards and that the Regional State Advisory Committee in each region may set this number higher for the region. FERC selected a 12 percent margin as a minimum in that it is two-thirds of the typical historical reserve margin target of 18 percent for large utilities. FERC emphasizes that most utilities historically used a reserve margin well above 12 percent.

- The traditional state-required planning horizon was 10-12 years. The horizons were established when the industry relied on new large hydroelectric, coal, or nuclear facilities which could take 10 or more years to site and construct. Today, most new resources are planned and developed over a much shorter time frame. Because the planning horizon should be no less than the time frame for developing new resources and development times vary from region to region, the planning horizon can depend on that region's reliance on coal, gas, wind, hydropower or new demand-response technology for new supply. This argues for allowing each region to determine it's own appropriate planning horizon.

- FERC proposes to have the Regional State Advisory Committee determine the planning horizon for the region.

- FERC defines reserve margin as: The reserve for a period is the amount of resources expected to be available during the period less the forecasted peak load. The reserve margin is the ratio of the reserves to the forecasted peak load. A region may use another measure of adequacy as long as the minimum level is the arithmetic equivalent of a 12 percent reserve margin. For example, many use capacity margin, which is the ratio of the reserves to the amount of resources expected to be available during the period. A capacity margin of 10.7 percent is the same as a reserve margin of 12 percent. Some may measure adequacy with a loss-of-load probability, called LOLP, which is a statistical measure of the expected total time during a period that generation will be unavailable to meet load. The common US standard is one day in ten years, which means that the sum of the hours during a ten year period when generation is expected to be short is 24 hours. Reserve margin cannot be translated directly into LOLP without studying a particular system. For example, an area served by a few large generators is more vulnerable to a shortage caused by an outage of one or two large generators than a similar area served by many smaller generators. The area with a few large generators may need a larger reserve margin to achieve the same LOLP. A general rule-of-thumb for a large US utility system is that an LOLP of one-day-in-ten-years is achieved with a reserve margin of about 18 percent.

Appendix

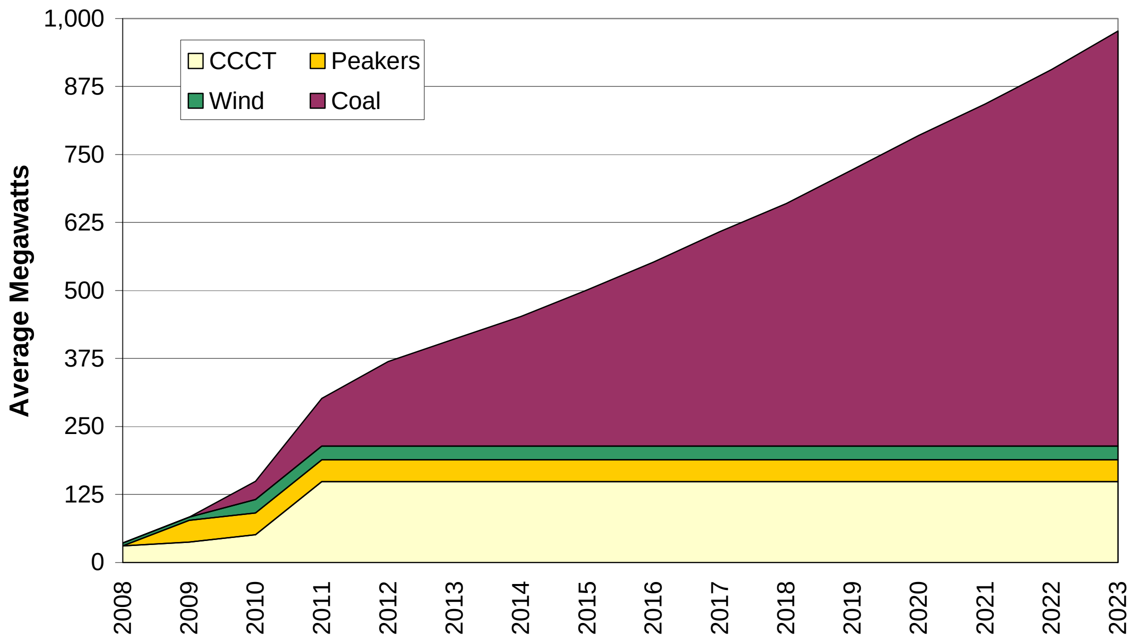
E

Detailed Results

Details of *Preferred Resource Strategy*

As discussed in *Section 7*, the *Preferred Resource Strategy* selects a mix of natural gas-fired, coal-fired, and wind generation. During the first ten years (2004-2013), varying amounts of each of these resources is selected. During the second ten years (2014-2023) of the IRP term, only coal-fired generation is constructed. Refer to the following chart for a depiction of resource selections under the *PRS*. Since no resources are added until 2008, the chart represents only 2008-2023.

Chart E.1
Preferred Resource Mix (in aMW)
2008-2023



Possibly the largest surprise in the study is the significant reliance on coal-fired generation. This is especially unexpected since AURORA selected only a modest amount of coal-fired generation during WECC capacity expansion (see *Appendix C*). Instead, AURORA relied on CCCTs for 80 percent of its new resources.

If the *Preferred Resource Strategy* had been based entirely on achieving the lowest cost, the LP Module would also have selected CCCTs instead of coal plants. The primary driver behind the construction of coal plants is the consideration of risk. Coal plants have low variable operating costs, making their level of fuel price risk much lower than CCCTs, for which two-thirds of the generation cost is fuel. Coal plants cost only a modest amount more than CCCTs, especially in the out years, yet the variability of net power supply expenses is significantly lower. This result is very intriguing, and the further study of coal plant economics has been identified as an action item. See *Section 8* for more detail.

Details of Strategy Results

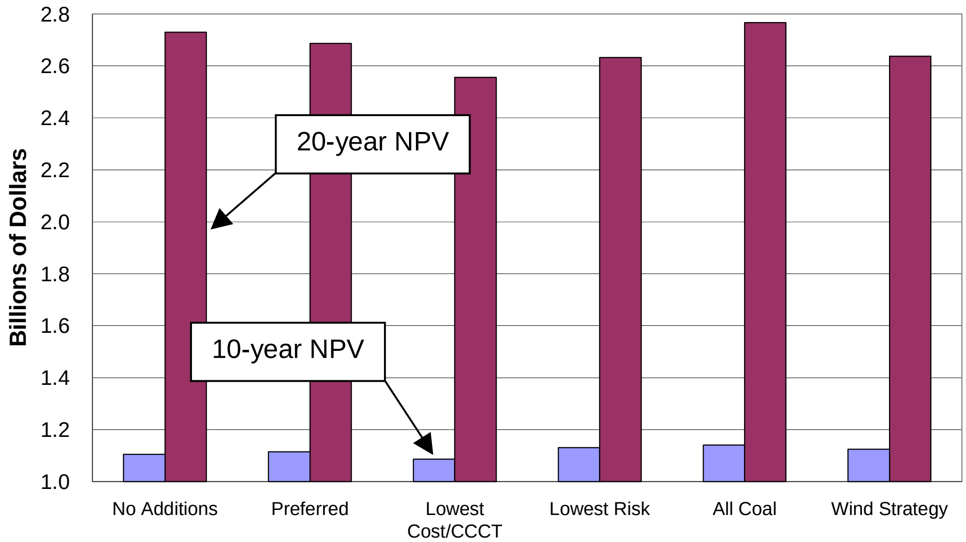
As discussed in *Section 5*, the Company analyzed several strategies in addition to the *Preferred Resource Strategy*. These strategies include *No Additions*, *Lowest Cost/CCCT*, *Lowest Risk*, *All Coal*, and *Wind Strategy*. The *PRS* was compared to each strategy on a cost, risk, capital expenditure, rate impact, market reliance, and qualitative basis. The result, as detailed below, was that the *PRS* performed very well across those criteria.

Average Expected Cost

Average expected costs across the strategies are not substantially different. During the first ten years, *No Additions* has a 0.9 percent lower average cost than the other strategies, even the *Lowest Cost* strategy. This is due to the fact that all of the strategies, with the exception of *No Additions*, must build something. Considering the Company's position in the early years of the study, it is less expensive to do nothing. Ignoring risk and focusing exclusively on lowest cost provides a modest savings of 2.5 percent over the *Preferred Resource Strategy*. Other strategies have higher costs than the *PRS* in the first ten years.

On a twenty-year basis, the *Preferred Resource Strategy* has higher costs than the *Lowest Cost* strategy. The *Lowest Risk* and *Wind Strategy* also provide a modest reduction in cost over the *PRS* over twenty years. Both *No Additions* and *All Coal* would increase costs modestly over the *Preferred Resource Strategy*. The following chart provides a comparison of costs for the various strategies.

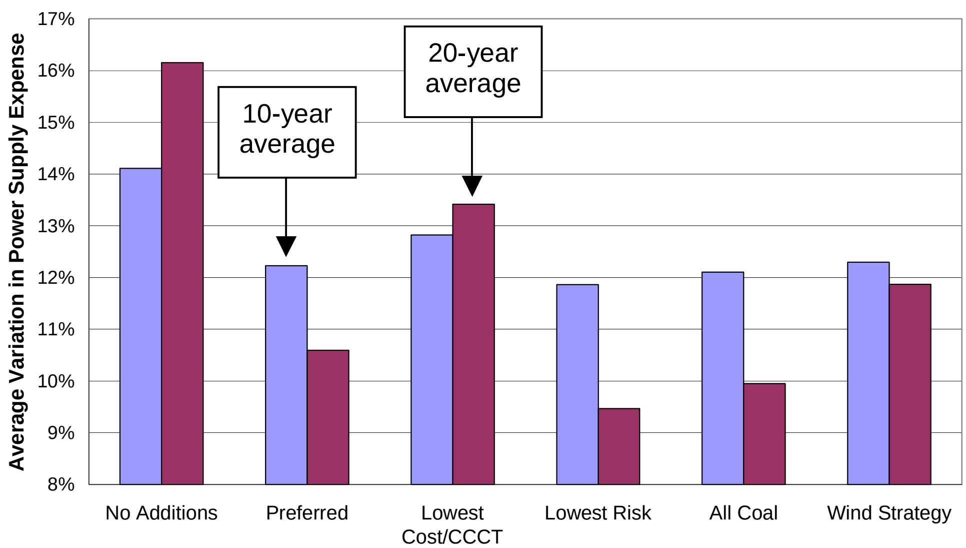
Chart E.2
Comparison of Net Power Supply Expense
2004-13 and 2004-23 Net Present Values
(in 2004 dollars)



Risk Assessment

Unlike average net power supply expense, the risk profiles for the various strategies vary substantially. To illustrate these differences, the average annual variation over the 200 iterations was evaluated for the 2004-2013 and 2004-2023 timeframes, as shown in the chart below.

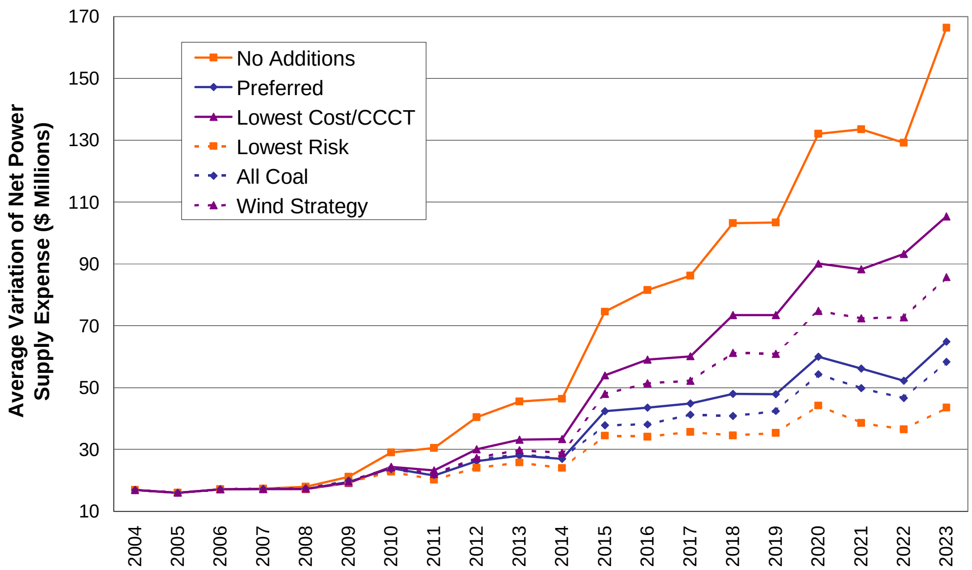
Chart E.3
Comparison of Strategy Risk Profiles
2004-13 and 2004-23 Average Annual Variation



All strategies provide a significant reduction in risk when compared to *No Additions*. Besides *No Additions*, the *Lowest Cost/CCCT* strategy is the riskiest over the first ten years. Over twenty years, the *Preferred Resource Strategy* reduces risk substantially when compared to the *No Additions*, *Lowest Cost/CCCT*, and *Wind Strategy* strategies. The *Lowest Risk* and *All Coal* strategies are only slightly less risky than the *PRS*.

Viewing risk over the timeframe of the IRP provides a more robust understanding of the impact of selecting a portfolio of resources. The following chart depicts each strategy over time.

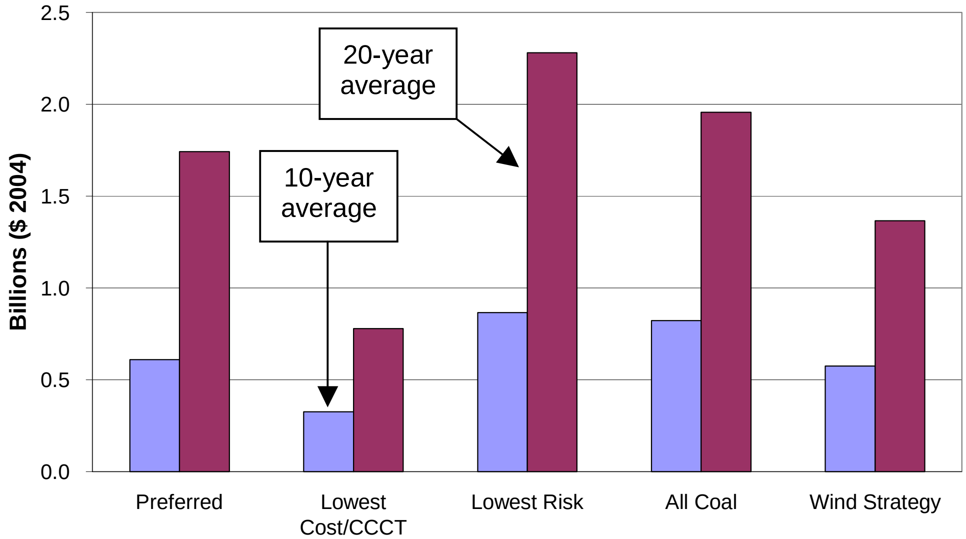
Chart E.4
Comparison of Strategy Risk Profiles
2004-2023



Capital Expenditures

The following chart depicts the capital costs of each strategy in 2004 dollars. Over the first ten years the varying strategies would require between $390 million and $1.02 billion in capital investments. The *PRS* requires $725 million, less than the *All Coal* and *Lowest Risk* strategies, but more than the *Lowest Cost/CCCT* strategies. The *Wind Strategy* is similar in cost to the *PRS*. Over 20 years the *Preferred Resource Strategy* will require $2.37 billion of capital.

Chart E.5
Capital Costs of Strategies (in 2004 dollars)
2004-2023

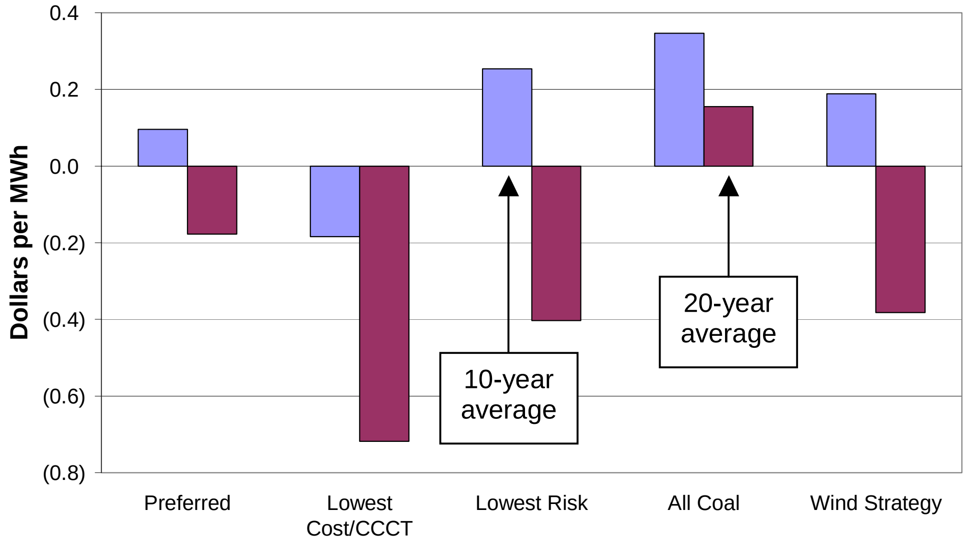


The Lowest Cost/CCCT strategy requires the smallest initial investment in new resources. The trade-off is higher future expenses for natural gas.

Rate Impacts

The following chart depicts the rate impact of each strategy due to changes in power supply costs. During the first ten years, all strategies besides *Lowest Cost/CCCT* increase rates very modestly when compared to the current embedded power supply cost of approximately $32 per MWh. In the case of the *Preferred Resource Strategy*, the increase is less than one dollar per MWh. With the exception of constructing new CCCT plants, buying from the wholesale marketplace for the first ten years of the IRP study could produce the lowest cost to customers.

Chart E.6
Rate Impacts (as Compared to *No Additions*)
2004-13 and 2004-23 Averages

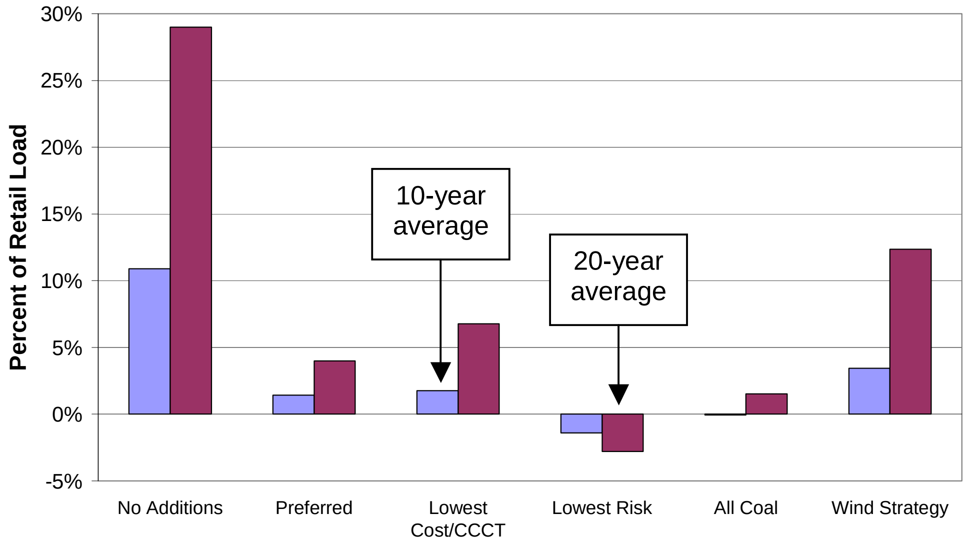


Over twenty years, all strategies besides *All Coal* are expected to reduce rate pressure when compared to a *No Additions* strategy. The *PRS* lowers costs by about $0.2 per MWh. The *Lowest Risk* and *Wind Strategy* reduce costs by between $0.2 and $0.5 dollars per MWh over twenty years compared to the *PRS*.

Reliance On the Wholesale Electricity Marketplace

As discussed earlier in this section, the Company relies on the wholesale marketplace to support surplus energy sales or meet load obligations. During any given calendar year, the Company expects that it would be selling and buying in different months, days, and hours. With the exception of *No Additions* and the *Wind Strategy*, all of the strategies rely on the market for fewer than seven percent of retail load over twenty years. The only strategy that contains a surplus of energy that must be sold into the wholesale marketplace is *Lowest Risk*. Its significant level of wind generation forces many sales, since the resource cannot be dispatched. The *Wind Strategy* does not have a substantial amount of surplus sales due to the large amount of peaking units that are oftentimes displaced. The other strategies include net purchases of electricity, primarily due to periods where it is less expensive to buy from the market than to generate. The following chart displays the market reliance of all strategies.

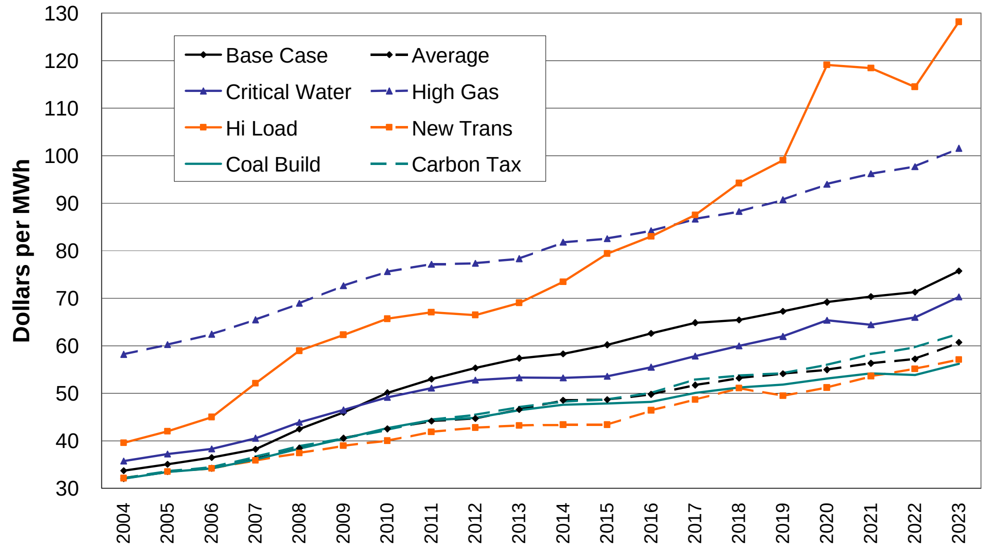
Chart E.7
Market Reliance
2004-13 and 2004-2023 Averages



Details of Scenario Results

As discussed in *Section 5*, the Company utilized several scenarios to evaluate the *Preferred Resource Strategy* and other strategies. Most of the discussion so far has been about strategies (e.g, *PRS*, *No Additions*, *All Coal*, etc.), and how they stack up under the *Base Case*. While the *Base Case* scenario incorporates the results of 200 iterations of Monte Carlo simulation, eight other scenarios were evaluated utilizing normal loads, hydroelectric generation, and natural gas prices (unless the scenario specifically designates a departure from average). These scenarios include *Average*, *Critical Water*, *High Gas*, *High Load*, *Load Loss*, *New Trans*, *Coal Build*, and *Carbon Tax*. The following chart compares average annual Northwest electricity prices under the *Base Case* with those resulting from the scenarios described above. The chart does not include the *Load Loss* scenario, as this scenario has no impact on market prices.

Chart E.8
Northwest Electricity Market Prices by Scenario
2004-2023



High Gas and *High Load* create the highest average market prices. *Critical Water* also drives prices up relative to many of the other scenarios, but to a much lesser extent. The impact of *Critical Water* is less significant in the later years, as hydro represents a smaller portion of total generation in the WECC.

An interesting result is the difference between the *Average* scenario and the *Base Case*. The average of load, hydroelectric generation, and natural gas prices in the 200 iterations that developed *Base Case* prices were used in creating the *Average* scenario, yet the average price under 200 iterations is higher than the single run using average loads, hydro, and natural gas prices.

The difference between *Base Case* and *Average* substantiates the Company's position that averages understate the true cost of serving customer loads and the value of generating resources. There are a number of reasons for this result. For example, revenues when the Company experiences above-average hydro are not adequate to compensate for when hydro generation is below average. Additionally, the Company's net position is correlated to the region, forcing it to buy at inopportune times.

Each of the scenarios, and their impacts on each portfolio strategy, is detailed below.

Critical Water

The *Critical Water* scenario assumes Northwest hydroelectric conditions equal the 1936-1937 water year. This scenario provides an estimate of how prices might change due to adverse hydroelectric generation, creating a situation where the WECC must rely more heavily on thermal generation. The table below shows the NPV of each resource strategy under *Critical Water* scenario. It also shows the difference between each resource strategy and the *Preferred Resource Strategy*.

Table E.1
Net Present Value of Resource Strategies
***Critical Water* Scenario**

	PRS	No Additions		Lowest Cost/CCCT		Lowest Risk		All Coal		Wind Strategy	
Period	**Value**	**Value**	**Diff**	**Value**	**Diff**	**Value**	**Diff**	**Value**	**Diff**	**Value**	**Diff**
2004-13	1.44	1.40	-2.4%	1.41	-2.2%	1.45	1.1%	1.46	1.5%	1.46	1.5%
2004-23	3.19	3.12	-2.0%	3.05	-4.4%	3.14	-1.4%	3.26	2.3%	3.18	-0.1%

Results under *Critical Water* are similar to the Base Case. The *No Additions* strategy cost is two percent lower than the *Preferred Resource Strategy* over twenty years. This differs from the *Base Case* where *No Additions* increases costs by 1.6 percent.

High Gas

For the *High Gas* scenario, natural gas prices were doubled. Instead of increasing from $3.95 per decatherm in 2004 to $6.75 in 2023, prices begin at $7.88 per decatherm and increase to $13.53. *Table E.2* compares the *Preferred Resource Strategy* to other considered strategies under the *High Gas* scenario.

Table E.2
Net Present Value of Strategies
***High Gas* Scenario**

	PRS	No Additions		Lowest Cost/CCCT		Lowest Risk		All Coal		Wind Strategy	
Period	**Value**	**Value**	**Diff**	**Value**	**Diff**	**Value**	**Diff**	**Value**	**Diff**	**Value**	**Diff**
2004-13	1.40	1.40	0.3%	1.44	3.0%	1.34	-4.1%	1.33	-5.3%	1.43	2.1%
2004-23	3.23	3.45	6.8%	3.59	11.0%	2.96	-8.5%	3.05	-5.5%	3.42	5.9%

High gas prices disadvantage gas-fired resources, relative to those using other fuels. The *Preferred Resource Strategy* relies on 189 aMW of gas-fired resources, while choosing coal and wind to account for 790 aMW of energy. As a result, its NPV does not change substantially from the *Base Case*. The *Lowest Cost/CCCT* strategy relies exclusively on natural gas-fired CCCTs and has costs much greater than the *PRS*.

High Load

For the *High Load* scenario, loads were increased by two standard deviations, or 12.5 percent through time. Natural gas prices are assumed to remain constant, which might not always hold true and would disadvantage gas-fired generation. WECC loads begin at 108,771 aMW in 2004, compared to 96,712 aMW in the *Base Case*. In 2023, loads are 167,371 aMW instead of 148,837 aMW. *Table E.3* compares the *Preferred Resource Strategy* to other considered strategies under the *High Load* scenario.

Table E.3
Net Present Value of Strategies
***High Load* Scenario**

	PRS	No Additions		Lowest Cost/CCCT		Lowest Risk		All Coal		Wind Strategy	
Period	**Value**	**Value**	**Diff**	**Value**	**Diff**	**Value**	**Diff**	**Value**	**Diff**	**Value**	**Diff**
2004-13	1.28	1.54	20.8%	1.26	-1.7%	1.25	-2.1%	1.30	1.7%	1.28	0.5%
2004-23	3.08	4.58	48.6%	2.99	-3.0%	2.78	-9.8%	3.15	2.3%	3.01	-2.4%

The *Preferred Resource Strategy* is modestly out-performed by the *Lowest Cost/CCCT* and *Lowest Risk* strategies during the first ten years of the IRP study. Over twenty years, the *Wind Strategy* also provides a modest benefit when compared to the *PRS*. The *No Additions* strategy is substantially higher in cost than the other strategies because the *High Load* scenario drives up the cost of serving load from the wholesale marketplace. The *PRS* provides a significant level of protection against higher loads because the portfolio contains resources that are capable of generating approximately fifteen percent more energy than in the Base Case, and it can therefore provide for increased customer requirements. On the other hand, because the *PRS* relies heavily on coal plants in the later years, the costs are higher. Coal plants are not as attractive as gas-fired plants in a high load scenario, as economic dispatch is limited due to higher fixed costs and lower variable costs.

Load Loss

Losing 300 aMW of system load will lower the Company's net power supply expense by 70 percent on a NPV basis between 2004 and 2013 under the *Preferred Resource Strategy*. The reduction over twenty years is 49 percent. Costs are reduced substantially due to the Company selling significant amounts of low-cost generation into the wholesale marketplace. With reduced loads, the Company does not require new resources until 2012, a full four years further out than in the *Base Case*. The following chart shows the reduction in required additions of generation under the *Load Loss* scenario.

Table E.4
Resource Build
***Base Case* and *Load Loss* Scenarios**

Period	Scenario	CCCT	SCCT	Wind	Coal	Total
First 10 Years	*Base Case*	149	40	25	197	411
	Load Loss	111	0	0	0	111
Full 20 Years	*Base Case*	149	40	25	763	977
	Load Loss	111	0	25	541	677

By reducing load, the Company's position changes substantially over the IRP timeframe as shown in the energy and capacity charts below. Capacity obligations were reduced on a percentage basis equivalent to the 300 aMW load reduction.

Table E.5
Loads and Resources Energy Forecast (aMW)
***Load Loss* Scenario**
2004-2008, 2013, 2018, 2023

	2004	2005	2006	2007	2008	2013	2018	2023
Obligations								
Retail Load	985	1,014	1,051	1,083	1,120	1,326	1,569	1,860
80% Conf. Interval	189	189	189	189	189	189	189	153
Total Obligations	*1,174*	*1,203*	*1,240*	*1,272*	*1,309*	*1,515*	*1,758*	*2,013*
Existing Resources								
Hydro	550	545	530	530	529	477	471	458
Net Contracts	156	157	175	177	177	58	59	12
Base Thermal	223	230	223	223	230	230	230	230
Gas Dispatch	158	156	158	158	156	158	158	156
Gas Peaking Units	181	181	181	181	181	181	181	181
Total Existing Resources	*1,268*	*1,269*	*1,267*	*1,269*	*1,273*	*1,104*	*1,099*	*1,037*
PRS Resource Additions								
Wind	0	0	0	0	0	(0)	25	25
Base Thermal	0	0	0	0	0	0	224	541
Gas Dispatch	0	0	0	0	0	111	111	111
Gas Peaking Units	0	0	0	0	0	0	0	0
Total PRS Resources	*0*	*0*	*0*	*0*	*0*	*111*	*360*	*677*
Net Position	**394**	**366**	**327**	**297**	**264**	**0**	**1**	**1**

Table E.6
Loads and Resources Capacity Forecast (MW)
***Load Loss* Scenario**
2004-2008, 2013, 2018, 2023

	2004	2005	2006	2007	2008	2013	2018	2023
Obligations								
Retail Load	1,022	1,067	1,122	1,169	1,224	1,534	1,900	2,332
Operating Reserves	107	107	105	105	105	108	126	150
Total Obligations	*1,129*	*1,174*	*1,226*	*1,274*	*1,329*	*1,642*	*2,026*	*2,482*
Existing Resources								
Hydro	1,177	1,177	1,135	1,134	1,133	1,043	1,035	998
Net Contracts	70	19	43	45	45	-73	78	-2
Base Thermal	272	272	272	272	272	272	272	272
Gas Dispatch	176	176	176	176	176	176	176	176
Gas Peaking Units	236	236	236	236	236	236	236	236
Total Existing Resources	*1,931*	*1,880*	*1,862*	*1,863*	*1,862*	*1,654*	*1,797*	*1,680*
PRS Resource Additions								
Wind	0	0	0	0	0	0	0	0
Base Thermal	0	0	0	0	0	0	260	628
Gas Dispatch	0	0	0	0	0	117	117	117
Gas Peaking Units	0	0	0	0	0	0	0	0
Total PRS Resources	*0*	*0*	*0*	*0*	*0*	*117*	*376*	*745*
Net Position	**802**	**706**	**636**	**589**	**533**	**129**	**148**	**-57**
Reserve Margin	*88.9%*	*76.2%*	*66.0%*	*59.4%*	*52.1%*	*15.5%*	*14.4%*	*4.0%*

The loss of 300 aMW of retail load exposes the Company to a similar level of annual power supply risk on a total cost basis. The comparison can be found in *Chart E.9.*

Chart E.9
Variation of Power Supply Expense From Expected Value Over 200 Iterations
2004-2023

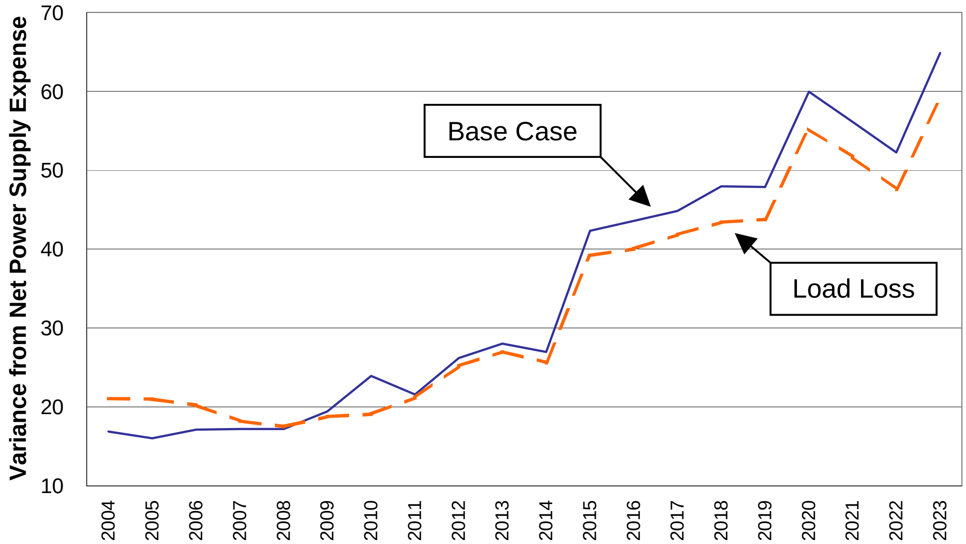


Table E.7
Net Present Value of Strategies
***Load Loss* Scenario**

	PRS	No Additions		Lowest Cost/CCCT		Lowest Risk		All Coal		Wind Strategy	
Period	**Value**	**Value**	**Diff**	**Value**	**Diff**	**Value**	**Diff**	**Value**	**Diff**	**Value**	**Diff**
2004-13	0.37	0.38	2.5%	0.37	0.0%	0.38	0.9%	0.40	6.7%	0.38	1.6%
2004-23	1.35	1.72	27.2%	1.28	-5.0%	1.36	0.3%	1.46	7.9%	1.33	-1.4%

Besides *No Additions*, only the *All Coal* strategy would be substantially more expensive between 2004 and 2013 than the *PRS*. Over twenty years the *Lowest Cost/CCCT* and *Wind Strategy* are modestly better than the *PRS*.

New Transmission

A lack of coal development is often attributed to a lack of transmission. Coal plants included in the various strategies all included an investment in transmission to approximate the development of new lines to move energy from their remote locations. The *New Transmission* scenario assumed four new 3,000 MW transmission lines were built as follows:

- Montana to the Northwest
- Wyoming to Southern Idaho
- Wyoming to Utah
- Utah to Southern California

The following table details the capacity expansion build in AURORA with the additional transfer capabilities.

Table E.8
Capacity Expansion Resource Summary (GW)
***New Trans* Scenario**

Year	CCCT	Coal	SCCT	Wind	Retire	Net
2004	0.00	0.00	0.00	0.00	(0.51)	(0.50)
2008	0.00	3.20	0.00	0.30	(7.52)	(4.01)
2013	5.60	14.40	0.00	8.50	(27.06)	1.45
2018	40.98	16.00	0.09	11.30	(35.70)	32.68
2023	68.14	16.40	0.18	13.00	(35.80)	61.94
	69.7%	16.8%	0.2%	13.3%		

The significant difference in the study is that 14.4 GW of additional coal-fired generation plants are constructed once the transmission lines are built to retire an additional 10 GW of less-efficient gas- and oil-fired plants. The impact on market prices with the new capacity expansion run was surprisingly modest; market prices in the Northwest were on average about 4.5 percent lower.

Table E.9 compares the *Preferred Resource Strategy* to other considered strategies.

Table E.9
Net Present Value of Strategies
***New Trans* Scenario**

	PRS	No Additions		Lowest Cost/CCCT		Lowest Risk		All Coal		Wind Strategy	
Period	**Value**	**Value**	**Diff**	**Value**	**Diff**	**Value**	**Diff**	**Value**	**Diff**	**Value**	**Diff**
2004-13	1.11	1.01	-9.1%	1.08	-2.8%	1.14	2.7%	1.14	2.4%	1.12	1.1%
2004-23	2.63	2.21	-15.9%	2.49	-5.6%	2.66	1.0%	2.72	3.2%	2.58	-1.9%

Where significant additional transmission capability is constructed out of Montana and Wyoming to the Northwest, Southern Idaho, and Southern California, the Company's *Preferred Resources Strategy* out-performs the *Lowest Risk* and *All Coal* strategies modestly. The *No Additions* strategy provides the greatest savings as spot market prices are held down in many periods by lower-cost coal-fired plants.

Coal Build

In the *Coal Build* scenario, all of the CCCT plants constructed in the AURORA capacity expansion run were replaced by coal plants. Northwest market prices were modestly lower when coal plants were used in lieu of CCCTs. The following table presents the net present value of the various strategies under the *Coal Build* scenario.

Table E.10
Net Present Value of Strategies
***Coal Build* Scenario**

	PRS	No Additions		Lowest Cost/CCCT		Lowest Risk		All Coal		Wind Strategy	
Period	**Value**	**Value**	**Diff**	**Value**	**Diff**	**Value**	**Diff**	**Value**	**Diff**	**Value**	**Diff**
2004-13	1.11	1.02	-8.1%	1.08	-2.8%	1.13	2.5%	1.13	2.3%	1.12	1.3%
2004-23	2.62	2.29	-12.7%	2.48	-5.5%	2.63	0.4%	2.70	3.1%	2.59	-1.4%

Because coal plants have low variable costs, the price volatility under a coal-build scenario is much lower than under the *Base Case*. Under such conditions, strategies based on building no additional resources or focusing on investments with low capital costs (CCCTs) tend to outperform the *Preferred Resource Strategy*.

Carbon Tax

CO_2 taxes disadvantage carbon-emitting resources, such as CCCT and coal plants. For the IRP, Northwest Power Planning Council (NWPPC) carbon tax assumptions were used, with prices increasing from $1.32 in 2004 to about $11 in 2023. The Company applied these charges to all CO_2 emissions in the WECC. Coal plants, with their higher carbon emission levels per MWh, are disadvantaged when compared to CCCT plants, which emit significant levels of carbon, but about half of coal plants. This can best be seen by reviewing the differences between the *Lowest Cost/CCCT* and the *All Coal* strategies in the following table.

Table E.11
Net Present Value of Strategies
***Carbon Tax* Scenario**

	PRS	No Additions		Lowest Cost/CCCT		Lowest Risk		All Coal		Wind Strategy	
Period	**Value**	**Value**	**Diff**	**Value**	**Diff**	**Value**	**Diff**	**Value**	**Diff**	**Value**	**Diff**
2004-13	1.14	1.04	-8.2%	1.10	-3.3%	1.16	1.8%	1.17	3.2%	1.15	0.8%
2004-23	2.78	2.39	-14.2%	2.55	-8.5%	2.69	-3.3%	2.91	4.6%	2.67	-4.0%

The *Lowest Cost/CCCT* build, relying entirely on CCCT plants, is 3.3 percent lower in cost than the *PRS* over the first ten years of the IRP timeframe. Over twenty years, the gap increases to 8.5 percent. This cost savings stems from the reliance of the *PRS* on coal plants. A comparison of the *Lowest Cost/CCCT* strategy to the *All Coal* strategy further illustrates this difference, with a spread of 6.5 percent during the first ten years and 13.1 percent over twenty years.

Appendix

F Load and Resource Tables

This appendix contains the following tables and charts depicting loads and resources for energy and capacity:

- Table F.1 – Annual Loads and Resources Energy Forecast – 2004-2023
- Tables F.2-F.21 – Monthly Loads and Resources Energy Forecast – 2004-2023
- Charts F.1-F.5 – Loads and Resources Monthly Energy Position – 2004, 2008, 2013, 2018, and 2023
- Table F.1 – Annual Loads and Resources Capacity Forecast – 2004-2023
- Tables F.2-F.21 – Monthly Loads and Resources Capacity Forecast – 2004-2023
- Chart F.6 – 2002 Hourly System Load Shapes by Quarter

Table F.1
Annual Loads & Resources Energy Forecast
2004-2023 (in aMW)

Last Updated 12/12/2002	**Notes**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
REQUIREMENTS																					
System Load	1	(985)	(1,014)	(1,051)	(1,083)	(1,120)	(1,165)	(1,207)	(1,248)	(1,285)	(1,326)	(1,364)	(1,414)	(1,465)	(1,517)	(1,569)	(1,620)	(1,671)	(1,731)	(1,793)	(1,860)
Contracts Out	2	(7)	(7)	(6)	(6)	(6)	(5)	(4)	(4)	(3)	(3)	(3)	(3)	(3)	(3)	(2)	(2)	(2)	(2)	(1)	(1)
Total Requirements		(992)	(1,021)	(1,057)	(1,089)	(1,126)	(1,171)	(1,211)	(1,251)	(1,288)	(1,329)	(1,367)	(1,417)	(1,468)	(1,520)	(1,572)	(1,622)	(1,672)	(1,732)	(1,795)	(1,862)
RESOURCES																					
Hydro	3	550	545	530	530	529	524	499	496	477	477	476	475	474	473	471	462	461	460	459	458
Contracts In	4	163	164	181	183	183	183	182	76	61	61	61	61	61	61	61	42	13	13	13	13
Base Load Thermals	5	223	230	223	223	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230
Gas Dispatch Units	6	158	156	158	158	156	158	158	156	158	158	156	158	158	156	158	158	156	158	158	156
Total Resources		1,094	1,095	1,092	1,094	1,098	1,095	1,069	958	926	926	922	924	923	920	920	892	860	862	861	857
Surplus (Deficit)		**102**	**74**	**35**	**5**	**(28)**	**(75)**	**(142)**	**(294)**	**(361)**	**(403)**	**(444)**	**(493)**	**(544)**	**(600)**	**(652)**	**(730)**	**(813)**	**(871)**	**(934)**	**(1,005)**

CONTINGENCY PLANNING																					
Confidence Interval	*7*	*(153)*	*(153)*	*(153)*	*(153)*	*(153)*	*(153)*	*(153)*	*(153)*	*(153)*	*(153)*	*(153)*	*(153)*	*(153)*	*(153)*	*(153)*	*(153)*	*(153)*	*(153)*	*(153)*	*(153)*
WNP-3 Obligation	*8*	*(36)*	*(36)*	*(36)*	*(36)*	*(36)*	*(36)*	*(36)*	*(36)*	*(36)*	*(36)*	*(36)*	*(36)*	*(36)*	*(36)*	*(36)*	*(20)*	-	-	-	-
Peaking Units	*9*	*181*	*181*	*181*	*181*	*181*	*181*	*181*	*181*	*181*	*181*	*181*	*181*	*181*	*181*	*181*	*181*	*181*	*181*	*181*	*181*
Surplus (Deficit) net position		***94***	***66***	***27***	***(3)***	***(36)***	***(83)***	***(149)***	***(302)***	***(369)***	***(411)***	***(452)***	***(501)***	***(552)***	***(608)***	***(660)***	***(722)***	***(785)***	***(843)***	***(906)***	***(977)***

Notes:

1. Load estimates are from the 2003 load forecast (08-27-2002) including the forecast for net Potlatch load.
2. Includes PacifiCorp Exchange Delivery, Nichols Pumping, and Canadian Entitlement Return contracts. Does not include WNP-3 Obligation.
3. Average (60-year) hydro generation for system hydro (Clark Fork and Spokane River projects) and contract hydro (mid-Columbia) based on NWPP 2000-01 Headwater Benefits Study.
   Contract hydro numbers reflect the Priest Rapids and Wanapum contract extensions beginning in 2005.
4. Includes small power contracts, Upriver, Black Creek, market purchases of 100 MW flat for 2004-2010. PacifiCorp Exchange Return, and WNP-3 Receipt. BPA Residential Exchange is zero, assumes contract monetization.
5. Includes Colstrip and Kettle Falls.
6. Includes Coyote Springs, Boulder Park, and Kettle Falls CT.
7. The confidence interval represents the 12-month average of reserve energy necessary to ensure nomore than a 10 percent probability of loads exceeding, and/or hydro underperforming, during a given month.
8. Represents highest level of potential obligation to BPA generally exercised under low hydro conditions.
9. Includes Northeast and Rathdrum, numbers reflect "full availability" adjusted for forced outage and maintenance.

Table F.2
Monthly Loads & Resources Energy Forecast – 2004 (in aMW)

December 12, 2002 Version

Year 2004	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS													
Average Load	**939**	1,052	1,026	1,001	889	848	845	909	901	834	879	1,001	1,077
Potlatch Load	***46***	*46*	*46*	*46*	*46*	*46*	*46*	*46*	*46*	*46*	*46*	*46*	*46*
TOTAL LOADS	**985**	**1,098**	**1,072**	**1,047**	**936**	**895**	**891**	**955**	**947**	**880**	**925**	**1,047**	**1,123**
CONTRACT RIGHTS													
Black Creek Hydro	**1**	0	0	0	0	0	0	0	11	0	0	0	0
Market Purchases	**100**	100	100	100	100	100	100	100	100	100	100	100	100
Pacificorp Exchange Return	**2**	12	13	0	0	0	0	0	0	0	0	0	0
PGE Capacity Return	**48**	48	47	48	48	50	48	46	50	44	50	48	44
Small Power	**3**	3	3	4	5	4	4	4	2	2	2	3	3
Upriver	**9**	12	12	13	12	11	12	6	3	4	6	8	11
WNP-3	**48**	116	112	57	57	0	0	0	0	0	0	116	116
TOTAL CONTRACT RIGHTS	**211**	**291**	**287**	**223**	**222**	**165**	**164**	**157**	**166**	**149**	**158**	**275**	**274**
CONTRACT OBLIGATIONS													
Canadian Entitlement	**6**	6	6	6	6	6	6	6	6	6	6	6	6
Nichols Pumping net of PGE	**1**	1	1	1	1	1	1	1	1	1	1	1	1
PGE Capacity	**48**	48	47	48	48	50	48	46	50	44	50	48	44
TOTAL CONTRACT OBLIGATIONS	**55**	**56**	**55**	**56**	**55**	**58**	**55**	**54**	**58**	**51**	**58**	**55**	**52**
NET CONTRACT POSITION	**156**	**236**	**233**	**167**	**167**	**108**	**108**	**103**	**109**	**98**	**100**	**219**	**223**
HYDRO RESOURCES (Average Water)													
Spokane River	**123**	128	149	156	159	159	150	101	60	76	94	107	143
Clark Fork	**325**	247	261	227	357	603	644	394	297	147	150	262	313
Mid-Columbia	**101**	143	119	99	83	91	112	98	103	84	85	85	114
Sub-Total	**550**	518	529	482	599	853	906	593	460	306	329	454	570
THERMAL RESOURCES (Full Capability)													
Boulder Park	**25**	25	25	25	25	25	25	25	25	25	25	25	25
Colstrip	**222**	222	222	222	222	222	222	222	222	222	222	222	222
Coyote Springs 2	**132**	134	134	133	133	131	129	127	127	131	133	134	134
Coyote Springs 2 duct burner	**10**	10	10	10	10	10	10	10	10	10	10	10	10
Kettle Falls	**47**	47	47	47	47	47	47	47	47	47	47	47	47
Kettle Falls CT	**7**	7	7	7	7	7	7	7	7	7	7	7	7
Northeast	**53**	56	56	55	53	52	51	50	50	52	53	55	56
Rathdrum	**150**	157	156	153	150	147	145	142	143	146	150	154	156
Sub-Total	**645**	658	655	651	646	642	637	631	631	639	646	653	657
TOTAL RESOURCES	**1,195**	**1,175**	**1,184**	**1,133**	**1,245**	**1,495**	**1,543**	**1,224**	**1,091**	**945**	**975**	**1,107**	**1,227**
MAINTENANCE AND FORCED OUTAGE													
Boulder Park	**2**	1	1	4	4	1	1	1	1	1	1	1	1
Colstrip	**42**	31	31	31	31	120	72	31	31	31	31	31	31
Coyote Springs 2	**11**	7	7	7	7	63	6	6	6	7	7	7	7
Coyote Springs 2 duct burner	**1**	0	0	1	1	5	1	1	1	1	1	1	0
Kettle Falls	**5**	3	3	3	3	23	3	3	3	3	3	3	3
Kettle Falls CT	**1**	1	1	1	1	3	1	1	1	1	1	1	1
Northeast	**3**	3	3	3	3	3	3	3	3	3	3	3	3
Rathdrum	**20**	16	16	15	15	45	45	14	14	15	15	15	16
TOTAL MAINT AND FORCED OUTAGE	**84**	**61**	**61**	**64**	**63**	**263**	**131**	**59**	**59**	**60**	**60**	**61**	**61**
NET POSITION	**Annual**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Conditions	**282**	**252**	**283**	**189**	**414**	**446**	**629**	**313**	**193**	**104**	**91**	**218**	**266**
80% Confidence Interval	**129**	**61**	**109**	**21**	**238**	**277**	**445**	**45**	**92**	**28**	**3**	**106**	**137**
WNP-3 Obligation	**36**	48	48	48	48	0	48	0	0	48	48	48	48
WNP-3 Adjusted 80% CI Position	**94**	13	61	(26)	191	277	397	45	92	(20)	(45)	58	89

Table F.3
Monthly Loads & Resources Energy Forecast – 2005 (in aMW)

December 12, 2002 Version

Year 2005	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS													
Average Load	**969**	1,088	1,059	1,033	919	875	872	936	929	863	906	1,030	1,115
Potlatch Load	*46*	*46*	*46*	*46*	*46*	*46*	*46*	*46*	*46*	*46*	*46*	*46*	*46*
TOTAL LOADS	**1,014**	**1,134**	**1,105**	**1,079**	**965**	**921**	**918**	**982**	**975**	**909**	**952**	**1,076**	**1,161**
CONTRACT RIGHTS													
Black Creek Hydro	**1**	0	0	0	0	0	0	0	11	0	0	0	0
Grant Displacement	**3**	0	0	0	0	0	0	0	0	0	0	20	20
Market Purchases	**100**	100	100	100	100	100	100	100	100	100	100	100	100
PGE Capacity Return	**48**	48	49	48	48	50	48	46	50	44	50	48	44
Small Power	**3**	3	3	4	5	4	4	4	2	2	2	3	3
Upriver	**9**	12	13	13	12	11	12	6	3	4	6	8	11
WNP-3	**48**	116	116	57	57	0	0	0	0	0	0	116	116
TOTAL CONTRACT RIGHTS	**212**	**280**	**281**	**223**	**222**	**165**	**164**	**157**	**166**	**149**	**158**	**295**	**295**
CONTRACT OBLIGATIONS													
Canadian Entitlement	**6**	6	6	6	6	6	6	6	6	6	6	4	4
Nichols Pumping net of PGE	**1**	1	1	1	1	1	1	1	1	1	1	1	1
PGE Capacity	**48**	48	49	48	48	50	48	46	50	44	50	48	44
TOTAL CONTRACT OBLIGATIONS	**55**	**56**	**56**	**56**	**55**	**58**	**55**	**54**	**58**	**51**	**58**	**53**	**50**
NET CONTRACT POSITION	**157**	**224**	**224**	**167**	**167**	**108**	**108**	**103**	**109**	**98**	**100**	**241**	**245**
HYDRO RESOURCES (Average Water)													
Spokane River	**123**	128	149	156	159	159	150	101	60	76	94	107	143
Clark Fork	**325**	247	261	227	357	603	644	394	297	147	150	262	313
Mid-Columbia	**97**	143	119	99	83	91	112	98	103	84	85	61	82
Sub-Total	**545**	518	529	482	599	853	906	593	460	306	329	429	539
THERMAL RESOURCES (Full Capability)													
Boulder Park	**25**	25	25	25	25	25	25	25	25	25	25	25	25
Colstrip	**222**	222	222	222	222	222	222	222	222	222	222	222	222
Coyote Springs 2	**132**	134	134	133	133	131	129	127	127	131	133	134	134
Coyote Springs 2 duct burner	**10**	10	10	10	10	10	10	10	10	10	10	10	10
Kettle Falls	**47**	47	47	47	47	47	47	47	47	47	47	47	47
Kettle Falls CT	**7**	7	7	7	7	7	7	7	7	7	7	7	7
Northeast	**53**	56	56	55	53	52	51	50	50	52	53	55	56
Rathdrum	**150**	157	156	153	150	147	145	142	143	146	150	154	156
Sub-Total	**645**	658	655	651	646	642	637	631	631	639	646	653	657
TOTAL RESOURCES	**1,191**	**1,175**	**1,184**	**1,133**	**1,245**	**1,495**	**1,543**	**1,224**	**1,091**	**945**	**975**	**1,082**	**1,195**
MAINTENANCE AND FORCED OUTAGE													
Boulder Park	**2**	1	1	4	4	1	1	1	1	1	1	1	1
Colstrip	**34**	31	31	31	31	74	31	31	31	31	31	31	31
Coyote Springs 2	**14**	7	102	7	7	7	6	6	6	7	7	7	7
Coyote Springs 2 duct burner	**1**	0	8	1	1	1	1	1	1	1	1	1	0
Kettle Falls	**5**	3	3	3	3	23	3	3	3	3	3	3	3
Kettle Falls CT	**1**	1	1	1	1	3	1	1	1	1	1	1	1
Northeast	**3**	3	3	3	3	3	3	3	3	3	3	3	3
Rathdrum	**20**	16	16	15	15	45	45	14	14	15	15	15	16
TOTAL MAINT AND FORCED OUTAGE	**79**	**61**	**163**	**64**	**63**	**156**	**90**	**59**	**59**	**60**	**60**	**61**	**61**
NET POSITION	**Annual**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Conditions	**254**	**204**	**140**	**158**	**385**	**526**	**643**	**286**	**165**	**75**	**63**	**187**	**218**
80% Confidence Interval	**101**	**13**	**(35)**	**(10)**	**209**	**357**	**460**	**18**	**63**	**(1)**	**(25)**	**75**	**89**
WNP-3 Obligation	**36**	48	48	48	48	0	48	0	0	48	48	48	48
WNP-3 Adjusted 80% CI Position	**66**	(34)	(82)	(58)	162	357	412	18	63	(49)	(72)	27	41

Table F.4
Monthly Loads & Resources Energy Forecast – 2006 (in aMW)

December 12, 2002 Version

Year 2006	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS													
Average Load	**1,006**	1,132	1,100	1,072	955	908	905	969	964	898	940	1,065	1,162
Potlatch Load	***46***	*46*	*46*	*46*	*46*	*46*	*46*	*46*	*46*	*46*	*46*	*46*	*46*
TOTAL LOADS	**1,051**	**1,178**	**1,146**	**1,118**	**1,000**	**954**	**951**	**1,015**	**1,010**	**944**	**986**	**1,111**	**1,207**
CONTRACT RIGHTS													
Black Creek Hydro	**1**	0	0	0	0	0	0	0	11	0	0	0	0
Grant Displacement	**20**	20	20	20	20	20	20	20	20	20	20	20	20
Market Purchases	**100**	100	100	100	100	100	100	100	100	100	100	100	100
PGE Capacity Return	**48**	48	49	48	48	50	48	46	50	44	50	48	44
Small Power	**3**	3	3	4	5	4	4	4	2	2	2	3	3
Upriver	**9**	12	13	13	12	11	12	6	3	4	6	8	11
WNP-3	**48**	116	116	57	57	0	0	0	0	0	0	116	116
TOTAL CONTRACT RIGHTS	**229**	**300**	**301**	**243**	**243**	**186**	**184**	**177**	**187**	**170**	**178**	**295**	**295**
CONTRACT OBLIGATIONS													
Canadian Entitlement	**5**	5	5	5	5	5	5	5	5	5	5	5	5
Nichols Pumping net of PGE	**1**	1	1	1	1	1	1	1	1	1	1	1	1
PGE Capacity	**48**	48	49	48	48	50	48	46	50	44	50	48	44
TOTAL CONTRACT OBLIGATIONS	**54**	**54**	**55**	**54**	**54**	**56**	**54**	**52**	**56**	**49**	**56**	**54**	**50**
NET CONTRACT POSITION	**176**	**246**	**246**	**189**	**189**	**130**	**130**	**125**	**131**	**120**	**122**	**241**	**245**
HYDRO RESOURCES (Average Water)													
Spokane River	**123**	128	149	156	159	159	150	101	60	76	94	107	143
Clark Fork	**325**	247	261	227	357	603	644	394	297	147	150	262	313
Mid-Columbia	**82**	110	91	75	77	85	97	81	85	63	64	64	87
Sub-Total	**530**	485	501	458	593	847	892	575	442	286	308	433	543
THERMAL RESOURCES (Full Capability)													
Boulder Park	**25**	25	25	25	25	25	25	25	25	25	25	25	25
Colstrip	**222**	222	222	222	222	222	222	222	222	222	222	222	222
Coyote Springs 2	**132**	134	134	133	133	131	129	127	127	131	133	134	134
Coyote Springs 2 duct burner	**10**	10	10	10	10	10	10	10	10	10	10	10	10
Kettle Falls	**47**	47	47	47	47	47	47	47	47	47	47	47	47
Kettle Falls CT	**7**	7	7	7	7	7	7	7	7	7	7	7	7
Northeast	**53**	56	56	55	53	52	51	50	50	52	53	55	56
Rathdrum	**150**	157	156	153	150	147	145	142	143	146	150	154	156
Sub-Total	**645**	658	655	651	646	642	637	631	631	639	646	653	657
TOTAL RESOURCES	**1,175**	**1,143**	**1,156**	**1,109**	**1,239**	**1,488**	**1,529**	**1,206**	**1,073**	**925**	**954**	**1,086**	**1,200**
MAINTENANCE AND FORCED OUTAGE													
Boulder Park	**2**	1	1	4	4	1	1	1	1	1	1	1	1
Colstrip	**42**	31	31	31	31	126	66	31	31	31	31	31	31
Coyote Springs 2	**11**	7	7	7	7	63	6	6	6	7	7	7	7
Coyote Springs 2 duct burner	**1**	0	0	1	1	5	1	1	1	1	1	1	0
Kettle Falls	**5**	3	3	3	3	23	3	3	3	3	3	3	3
Kettle Falls CT	**1**	1	1	1	1	3	1	1	1	1	1	1	1
Northeast	**3**	3	3	3	3	3	3	3	3	3	3	3	3
Rathdrum	**20**	16	16	15	15	45	45	14	14	15	15	15	16
TOTAL MAINT AND FORCED OUTAGE	**84**	**61**	**61**	**64**	**63**	**269**	**125**	**59**	**59**	**60**	**60**	**61**	**61**
NET POSITION	**Annual**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Conditions	**216**	**150**	**195**	**116**	**365**	**395**	**583**	**257**	**134**	**41**	**30**	**155**	**176**
80% Confidence Interval	**63**	**(41)**	**21**	**(51)**	**190**	**227**	**399**	**(11)**	**33**	**(35)**	**(58)**	**43**	**47**
WNP-3 Obligation	**36**	48	48	48	48	0	48	0	0	48	48	48	48
WNP-3 Adjusted 80% CI Position	**27**	(89)	(27)	(99)	142	227	352	(11)	33	(83)	(105)	(4)	(1)

Table F.5
Monthly Loads & Resources Energy Forecast – 2007 (in aMW)

December 12, 2002 Version

Year 2007	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS													
Average Load	**1,035**	1,167	1,133	1,103	983	934	931	996	992	927	967	1,094	1,200
Potlatch Load	***48***	*48*	*48*	*48*	*48*	*48*	*48*	*48*	*48*	*48*	*48*	*48*	*48*
TOTAL LOADS	**1,083**	**1,215**	**1,180**	**1,151**	**1,031**	**982**	**979**	**1,043**	**1,040**	**975**	**1,015**	**1,142**	**1,248**
CONTRACT RIGHTS													
Black Creek Hydro	**1**	0	0	0	0	0	0	0	11	0	0	0	0
Grant Displacement	**22**	22	22	22	22	22	22	22	22	22	22	22	22
Market Purchases	**100**	100	100	100	100	100	100	100	100	100	100	100	100
PGE Capacity Return	**48**	48	49	48	48	50	48	46	50	44	50	48	44
Small Power	**3**	3	3	4	5	4	4	4	2	2	2	3	3
Upriver	**9**	12	13	13	12	11	12	6	3	4	6	8	11
WNP-3	**48**	116	116	57	57	0	0	0	0	0	0	116	116
TOTAL CONTRACT RIGHTS	**231**	**302**	**303**	**245**	**245**	**188**	**186**	**179**	**189**	**172**	**180**	**297**	**297**
CONTRACT OBLIGATIONS													
Canadian Entitlement	**5**	5	5	5	5	5	5	5	5	5	5	5	5
Nichols Pumping net of PGE	**1**	1	1	1	1	1	1	1	1	1	1	1	1
PGE Capacity	**48**	48	49	48	48	50	48	46	50	44	50	48	44
TOTAL CONTRACT OBLIGATIONS	**54**	**54**	**55**	**54**	**54**	**56**	**54**	**52**	**56**	**49**	**56**	**54**	**50**
NET CONTRACT POSITION	**178**	**248**	**248**	**191**	**191**	**132**	**132**	**127**	**133**	**122**	**124**	**243**	**247**
HYDRO RESOURCES (Average Water)													
Spokane River	**123**	128	149	156	159	159	150	101	60	76	94	107	143
Clark Fork	**325**	247	261	227	357	603	644	394	297	147	150	262	313
Mid-Columbia	**81**	109	90	75	77	85	97	80	84	63	64	64	86
Sub-Total	**530**	484	500	457	593	847	892	575	441	285	308	432	542
THERMAL RESOURCES (Full Capability)													
Boulder Park	**25**	25	25	25	25	25	25	25	25	25	25	25	25
Colstrip	**222**	222	222	222	222	222	222	222	222	222	222	222	222
Coyote Springs 2	**132**	134	134	133	133	131	129	127	127	131	133	134	134
Coyote Springs 2 duct burner	**10**	10	10	10	10	10	10	10	10	10	10	10	10
Kettle Falls	**47**	47	47	47	47	47	47	47	47	47	47	47	47
Kettle Falls CT	**7**	7	7	7	7	7	7	7	7	7	7	7	7
Northeast	**53**	56	56	55	53	52	51	50	50	52	53	55	56
Rathdrum	**150**	157	156	153	150	147	145	142	143	146	150	154	156
Sub-Total	**645**	658	655	651	646	642	637	631	631	639	646	653	657
TOTAL RESOURCES	**1,175**	**1,142**	**1,155**	**1,108**	**1,239**	**1,488**	**1,528**	**1,205**	**1,072**	**924**	**954**	**1,085**	**1,199**
MAINTENANCE AND FORCED OUTAGE													
Boulder Park	**2**	1	1	4	4	1	1	1	1	1	1	1	1
Colstrip	**42**	31	31	31	31	108	85	31	31	31	31	31	31
Coyote Springs 2	**11**	7	7	7	7	63	6	6	6	7	7	7	7
Coyote Springs 2 duct burner	**1**	0	0	1	1	5	1	1	1	1	1	1	0
Kettle Falls	**5**	3	3	3	3	23	3	3	3	3	3	3	3
Kettle Falls CT	**1**	1	1	1	1	3	1	1	1	1	1	1	1
Northeast	**3**	3	3	3	3	3	3	3	3	3	3	3	3
Rathdrum	**20**	16	16	15	15	45	45	14	14	15	15	15	16
TOTAL MAINT AND FORCED OUTAGE	**84**	**61**	**61**	**64**	**63**	**250**	**144**	**59**	**59**	**60**	**60**	**61**	**61**
NET POSITION	**Annual**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Conditions	**186**	**113**	**162**	**85**	**336**	**387**	**537**	**230**	**106**	**12**	**3**	**126**	**137**
80% Confidence Interval	**33**	**(77)**	**(13)**	**(83)**	**161**	**219**	**354**	**(38)**	**4**	**(64)**	**(85)**	**14**	**8**
WNP-3 Obligation	**36**	48	48	48	48	0	48	0	0	48	48	48	48
WNP-3 Adjusted 80% CI Position	**(3)**	(125)	(61)	(131)	113	219	306	(38)	4	(112)	(133)	(33)	(40)

Table F.6
Monthly Loads & Resources Energy Forecast – 2008 (in aMW)

December 12, 2002 Version

Year 2008	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS													
Average Load	**1,072**	1,211	1,173	1,142	1,019	967	964	1,029	1,027	962	1,001	1,129	1,241
Potlatch Load	*48*	*48*	*48*	*48*	*48*	*48*	*48*	*48*	*48*	*48*	*48*	*48*	*48*
TOTAL LOADS	**1,120**	**1,259**	**1,221**	**1,190**	**1,067**	**1,015**	**1,012**	**1,077**	**1,075**	**1,010**	**1,049**	**1,177**	**1,289**
CONTRACT RIGHTS													
Black Creek Hydro	**1**	0	0	0	0	0	0	0	11	0	0	0	0
Grant Displacement	**22**	22	22	22	22	22	22	22	22	22	22	22	22
Market Purchases	**100**	100	100	100	100	100	100	100	100	100	100	100	100
PGE Capacity Return	**48**	48	47	48	48	50	48	46	50	44	50	48	44
Small Power	**3**	3	3	4	5	4	4	4	2	2	2	3	3
Upriver	**9**	12	12	13	12	11	12	6	3	4	6	8	11
WNP-3	**48**	116	112	57	57	0	0	0	0	0	0	116	116
TOTAL CONTRACT RIGHTS	**231**	**302**	**297**	**245**	**245**	**188**	**186**	**179**	**189**	**172**	**180**	**297**	**297**
CONTRACT OBLIGATIONS													
Canadian Entitlement	**5**	5	5	5	5	5	5	5	5	5	5	5	5
Nichols Pumping net of PGE	**1**	1	1	1	1	1	1	1	1	1	1	1	1
PGE Capacity	**48**	48	47	48	48	50	48	46	50	44	50	48	44
TOTAL CONTRACT OBLIGATIONS	**53**	**54**	**53**	**54**	**54**	**56**	**53**	**52**	**56**	**49**	**56**	**53**	**50**
NET CONTRACT POSITION	**177**	**248**	**244**	**191**	**191**	**132**	**132**	**127**	**133**	**122**	**124**	**243**	**247**
HYDRO RESOURCES (Average Water)													
Spokane River	**123**	128	149	156	159	159	150	101	60	76	94	107	143
Clark Fork	**325**	247	261	227	357	603	644	394	297	147	150	262	313
Mid-Columbia	**80**	108	89	74	76	84	97	79	84	62	63	63	85
Sub-Total	**529**	483	499	456	592	846	891	574	441	284	307	431	541
THERMAL RESOURCES (Full Capability)													
Boulder Park	**25**	25	25	25	25	25	25	25	25	25	25	25	25
Colstrip	**222**	222	222	222	222	222	222	222	222	222	222	222	222
Coyote Springs 2	**132**	134	134	133	133	131	129	127	127	131	133	134	134
Coyote Springs 2 duct burner	**10**	10	10	10	10	10	10	10	10	10	10	10	10
Kettle Falls	**47**	47	47	47	47	47	47	47	47	47	47	47	47
Kettle Falls CT	**7**	7	7	7	7	7	7	7	7	7	7	7	7
Northeast	**53**	56	56	55	53	52	51	50	50	52	53	55	56
Rathdrum	**150**	157	156	153	150	147	145	142	143	146	150	154	156
Sub-Total	**645**	658	655	651	646	642	637	631	631	639	646	653	657
TOTAL RESOURCES	**1,174**	**1,141**	**1,154**	**1,107**	**1,239**	**1,488**	**1,528**	**1,205**	**1,072**	**924**	**953**	**1,084**	**1,198**
MAINTENANCE AND FORCED OUTAGE													
Boulder Park	**2**	1	1	4	4	1	1	1	1	1	1	1	1
Colstrip	**34**	31	31	31	31	74	31	31	31	31	31	31	31
Coyote Springs 2	**14**	7	99	7	7	7	6	6	6	7	7	7	7
Coyote Springs 2 duct burner	**1**	0	7	1	1	1	1	1	1	1	1	1	0
Kettle Falls	**5**	3	3	3	3	23	3	3	3	3	3	3	3
Kettle Falls CT	**1**	1	1	1	1	3	1	1	1	1	1	1	1
Northeast	**3**	3	3	3	3	3	3	3	3	3	3	3	3
Rathdrum	**20**	16	16	15	15	45	45	14	14	15	15	15	16
TOTAL MAINT AND FORCED OUTAGE	**79**	**61**	**160**	**64**	**63**	**156**	**90**	**59**	**59**	**60**	**60**	**61**	**61**
NET POSITION	**Annual**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Conditions	**153**	**69**	**17**	**45**	**300**	**449**	**558**	**196**	**71**	**(24)**	**(32)**	**90**	**95**
80% Confidence Interval	**(0)**	**(122)**	**(158)**	**(123)**	**125**	**280**	**374**	**(72)**	**(31)**	**(100)**	**(120)**	**(22)**	**(34)**
WNP-3 Obligation	**36**	48	48	48	48	0	48	0	0	48	48	48	48
WNP-3 Adjusted 80% CI Position	**(36)**	(170)	(205)	(171)	77	280	327	(72)	(31)	(148)	(167)	(69)	(82)

Table F.7
Monthly Loads & Resources Energy Forecast – 2009 (in aMW)

December 12, 2002 Version

Year 2009	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS													
Average Load	**1,115**	1,263	1,222	1,188	1,062	1,006	1,003	1,068	1,068	1,004	1,041	1,171	1,290
Potlatch Load	*50*	*50*	*50*	*50*	*50*	*50*	*50*	*50*	*50*	*50*	*50*	*50*	*50*
TOTAL LOADS	**1,165**	**1,313**	**1,272**	**1,238**	**1,112**	**1,056**	**1,053**	**1,118**	**1,118**	**1,054**	**1,091**	**1,221**	**1,340**
CONTRACT RIGHTS													
Black Creek Hydro	**1**	0	0	0	0	0	0	0	11	0	0	0	0
Grant Displacement	**22**	22	22	22	22	22	22	22	22	22	22	22	22
Market Purchases	**100**	100	100	100	100	100	100	100	100	100	100	100	100
PGE Capacity Return	**48**	48	49	48	48	50	48	46	50	44	50	48	44
Small Power	**3**	3	3	4	5	4	4	4	2	2	2	3	3
Upriver	**9**	12	13	13	12	11	12	6	3	4	6	8	11
WNP-3	**48**	116	116	57	57	0	0	0	0	0	0	116	116
TOTAL CONTRACT RIGHTS	**231**	**302**	**303**	**245**	**245**	**188**	**186**	**179**	**189**	**172**	**180**	**297**	**297**
CONTRACT OBLIGATIONS													
Canadian Entitlement	**4**	5	5	5	5	5	5	5	5	5	5	3	3
Nichols Pumping net of PGE	**1**	1	1	1	1	1	1	1	1	1	1	1	1
PGE Capacity	**48**	48	49	48	48	50	48	46	50	44	50	48	44
TOTAL CONTRACT OBLIGATIONS	**53**	**54**	**55**	**54**	**53**	**56**	**53**	**52**	**56**	**49**	**56**	**52**	**48**
NET CONTRACT POSITION	**178**	**248**	**248**	**191**	**191**	**132**	**132**	**127**	**133**	**122**	**124**	**245**	**248**
HYDRO RESOURCES (Average Water)													
Spokane River	**123**	128	149	156	159	159	150	101	60	76	94	107	143
Clark Fork	**325**	247	261	227	357	603	644	394	297	147	150	262	313
Mid-Columbia	**75**	107	88	73	76	84	96	79	83	61	62	39	53
Sub-Total	**524**	482	498	456	592	846	891	574	440	284	306	407	509
THERMAL RESOURCES (Full Capability)													
Boulder Park	**25**	25	25	25	25	25	25	25	25	25	25	25	25
Colstrip	**222**	222	222	222	222	222	222	222	222	222	222	222	222
Coyote Springs 2	**132**	134	134	133	133	131	129	127	127	131	133	134	134
Coyote Springs 2 duct burner	**10**	10	10	10	10	10	10	10	10	10	10	10	10
Kettle Falls	**47**	47	47	47	47	47	47	47	47	47	47	47	47
Kettle Falls CT	**7**	7	7	7	7	7	7	7	7	7	7	7	7
Northeast	**53**	56	56	55	53	52	51	50	50	52	53	55	56
Rathdrum	**150**	157	156	153	150	147	145	142	143	146	150	154	156
Sub-Total	**645**	658	655	651	646	642	637	631	631	639	646	653	657
TOTAL RESOURCES	**1,169**	**1,140**	**1,153**	**1,107**	**1,239**	**1,488**	**1,527**	**1,204**	**1,071**	**923**	**953**	**1,060**	**1,166**
MAINTENANCE AND FORCED OUTAGE													
Boulder Park	**2**	1	1	4	4	1	1	1	1	1	1	1	1
Colstrip	**34**	31	31	31	31	74	31	31	31	31	31	31	31
Coyote Springs 2	**11**	7	7	7	7	63	6	6	6	7	7	7	7
Coyote Springs 2 duct burner	**1**	0	0	1	1	5	1	1	1	1	1	1	0
Kettle Falls	**5**	3	3	3	3	23	3	3	3	3	3	3	3
Kettle Falls CT	**1**	1	1	1	1	3	1	1	1	1	1	1	1
Northeast	**3**	3	3	3	3	3	3	3	3	3	3	3	3
Rathdrum	**20**	16	16	15	15	45	45	14	14	15	15	15	16
TOTAL MAINT AND FORCED OUTAGE	**76**	**61**	**61**	**64**	**63**	**216**	**90**	**59**	**59**	**60**	**60**	**61**	**61**
NET POSITION	**Annual**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Conditions	**105**	**13**	**69**	**(4)**	**256**	**347**	**516**	**154**	**27**	**(69)**	**(74)**	**23**	**13**
80% Confidence Interval	**(48)**	**(177)**	**(106)**	**(172)**	**80**	**178**	**333**	**(114)**	**(75)**	**(145)**	**(163)**	**(88)**	**(116)**
WNP-3 Obligation	**36**	48	48	48	48	0	48	0	0	48	48	48	48
WNP-3 Adjusted 80% CI Position	**(83)**	(225)	(153)	(220)	32	178	285	(114)	(75)	(193)	(210)	(136)	(163)

Table F.8
Monthly Loads & Resources Energy Forecast – 2010 (in aMW)

December 12, 2002 Version

Year 2010	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS													
Average Load	**1,157**	1,313	1,268	1,232	1,102	1,043	1,041	1,106	1,108	1,045	1,080	1,211	1,337
Potlatch Load	***50***	*50*	*50*	*50*	*50*	*50*	*50*	*50*	*50*	*50*	*50*	*50*	*50*
TOTAL LOADS	**1,207**	**1,363**	**1,318**	**1,282**	**1,152**	**1,093**	**1,091**	**1,156**	**1,158**	**1,094**	**1,129**	**1,261**	**1,387**
CONTRACT RIGHTS													
Black Creek Hydro	**1**	0	0	0	0	0	0	0	11	0	0	0	0
Grant Displacement	**21**	21	21	21	21	21	21	21	21	21	21	21	21
Market Purchases	**100**	100	100	100	100	100	100	100	100	100	100	100	100
PGE Capacity Return	**48**	48	49	48	48	50	48	46	50	44	50	48	44
Small Power	**3**	3	3	4	5	4	4	4	2	2	2	3	3
Upriver	**9**	12	13	13	12	11	12	6	3	4	6	8	11
WNP-3	**48**	116	116	57	57	0	0	0	0	0	0	116	116
TOTAL CONTRACT RIGHTS	**230**	**300**	**301**	**243**	**243**	**186**	**184**	**177**	**187**	**170**	**179**	**295**	**295**
CONTRACT OBLIGATIONS													
Canadian Entitlement	**3**	3	3	3	3	3	3	3	3	3	3	3	3
Nichols Pumping net of PGE	**1**	1	1	1	1	1	1	1	1	1	1	1	1
PGE Capacity	**48**	48	49	48	48	50	48	46	50	44	50	48	44
TOTAL CONTRACT OBLIGATIONS	**52**	**52**	**53**	**52**	**52**	**54**	**52**	**50**	**54**	**48**	**54**	**52**	**48**
NET CONTRACT POSITION	**178**	**248**	**248**	**191**	**191**	**131**	**132**	**127**	**132**	**122**	**124**	**243**	**247**
HYDRO RESOURCES (Average Water)													
Spokane River	**123**	128	149	156	159	159	150	101	60	76	94	107	143
Clark Fork	**325**	247	261	227	357	603	644	394	297	147	150	262	313
Mid-Columbia	**51**	71	57	46	47	52	63	51	54	38	39	39	53
Sub-Total	**499**	445	467	429	564	814	857	546	411	261	283	407	509
THERMAL RESOURCES (Full Capability)													
Boulder Park	**25**	25	25	25	25	25	25	25	25	25	25	25	25
Colstrip	**222**	222	222	222	222	222	222	222	222	222	222	222	222
Coyote Springs 2	**132**	134	134	133	133	131	129	127	127	131	133	134	134
Coyote Springs 2 duct burner	**10**	10	10	10	10	10	10	10	10	10	10	10	10
Kettle Falls	**47**	47	47	47	47	47	47	47	47	47	47	47	47
Kettle Falls CT	**7**	7	7	7	7	7	7	7	7	7	7	7	7
Northeast	**53**	56	56	55	53	52	51	50	50	52	53	55	56
Rathdrum	**150**	157	156	153	150	147	145	142	143	146	150	154	156
Sub-Total	**645**	658	655	651	646	642	637	631	631	639	646	653	657
TOTAL RESOURCES	**1,145**	**1,103**	**1,122**	**1,080**	**1,210**	**1,455**	**1,494**	**1,176**	**1,043**	**900**	**929**	**1,060**	**1,166**
MAINTENANCE AND FORCED OUTAGE													
Boulder Park	**2**	1	1	4	4	1	1	1	1	1	1	1	1
Colstrip	**34**	31	31	31	31	74	31	31	31	31	31	31	31
Coyote Springs 2	**11**	7	7	7	7	63	6	6	6	7	7	7	7
Coyote Springs 2 duct burner	**1**	0	0	1	1	5	1	1	1	1	1	1	0
Kettle Falls	**5**	3	3	3	3	23	3	3	3	3	3	3	3
Kettle Falls CT	**1**	1	1	1	1	3	1	1	1	1	1	1	1
Northeast	**3**	3	3	3	3	3	3	3	3	3	3	3	3
Rathdrum	**20**	16	16	15	15	45	45	14	14	15	15	15	16
TOTAL MAINT AND FORCED OUTAGE	**76**	**61**	**61**	**64**	**63**	**216**	**90**	**59**	**59**	**60**	**60**	**61**	**61**
NET POSITION	**Annual**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Conditions	**39**	**(73)**	**(9)**	**(76)**	**186**	**277**	**445**	**88**	**(42)**	**(132)**	**(136)**	**(18)**	**(35)**
80% Confidence Interval	**(114)**	**(264)**	**(184)**	**(243)**	**10**	**108**	**262**	**(179)**	**(144)**	**(209)**	**(224)**	**(130)**	**(164)**
WNP-3 Obligation	**36**	48	48	48	48	0	48	0	0	48	48	48	48
WNP-3 Adjusted 80% CI Position	**(149)**	(312)	(231)	(291)	(37)	108	214	(179)	(144)	(257)	(272)	(178)	(212)

Table F.9
Monthly Loads & Resources Energy Forecast – 2011 (in aMW)

December 12, 2002 Version

Year 2011	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS													
Average Load	**1,196**	1,360	1,311	1,274	1,141	1,078	1,076	1,141	1,145	1,082	1,116	1,248	1,381
Potlatch Load	***52***	*52*	*52*	*52*	*52*	*52*	*52*	*52*	*52*	*52*	*52*	*52*	*52*
TOTAL LOADS	**1,248**	**1,411**	**1,363**	**1,326**	**1,193**	**1,130**	**1,128**	**1,193**	**1,197**	**1,134**	**1,167**	**1,300**	**1,433**
CONTRACT RIGHTS													
Black Creek Hydro	**1**	0	0	0	0	0	0	0	11	0	0	0	0
Grant Displacement	**15**	21	21	21	21	21	21	21	21	21	0	0	0
PGE Capacity Return	**48**	48	49	48	48	50	48	46	50	44	50	48	44
Small Power	**3**	3	3	4	5	4	4	4	2	2	2	3	3
Upriver	**9**	12	13	13	12	11	12	6	3	4	6	8	11
WNP-3	**48**	116	116	57	57	0	0	0	0	0	0	116	116
TOTAL CONTRACT RIGHTS	**124**	**200**	**201**	**143**	**143**	**86**	**84**	**77**	**87**	**70**	**58**	**175**	**174**
CONTRACT OBLIGATIONS													
Canadian Entitlement	**3**	3	3	3	3	3	3	3	3	3	3	2	2
Nichols Pumping net of PGE	**1**	1	1	1	1	1	1	1	1	1	1	1	1
PGE Capacity	**48**	48	49	48	48	50	48	46	50	44	50	48	44
TOTAL CONTRACT OBLIGATIONS	**52**	**52**	**53**	**52**	**52**	**54**	**52**	**50**	**54**	**48**	**54**	**51**	**47**
NET CONTRACT POSITION	**73**	**148**	**148**	**91**	**91**	**32**	**32**	**27**	**33**	**22**	**4**	**124**	**127**
HYDRO RESOURCES (Average Water)													
Spokane River	**123**	128	149	156	159	159	150	101	60	76	94	107	143
Clark Fork	**325**	247	261	227	357	603	644	394	297	147	150	262	313
Mid-Columbia	**47**	70	56	45	47	51	62	50	54	37	38	23	33
Sub-Total	**496**	444	466	428	563	813	856	545	411	260	282	392	489
THERMAL RESOURCES (Full Capability)													
Boulder Park	**25**	25	25	25	25	25	25	25	25	25	25	25	25
Colstrip	**222**	222	222	222	222	222	222	222	222	222	222	222	222
Coyote Springs 2	**132**	134	134	133	133	131	129	127	127	131	133	134	134
Coyote Springs 2 duct burner	**10**	10	10	10	10	10	10	10	10	10	10	10	10
Kettle Falls	**47**	47	47	47	47	47	47	47	47	47	47	47	47
Kettle Falls CT	**7**	7	7	7	7	7	7	7	7	7	7	7	7
Northeast	**53**	56	56	55	53	52	51	50	50	52	53	55	56
Rathdrum	**150**	157	156	153	150	147	145	142	143	146	150	154	156
Sub-Total	**645**	658	655	651	646	642	637	631	631	639	646	653	657
TOTAL RESOURCES	**1,141**	**1,102**	**1,121**	**1,079**	**1,209**	**1,455**	**1,493**	**1,175**	**1,042**	**899**	**929**	**1,045**	**1,146**
MAINTENANCE AND FORCED OUTAGE													
Boulder Park	**2**	1	1	4	4	1	1	1	1	1	1	1	1
Colstrip	**34**	31	31	31	31	74	31	31	31	31	31	31	31
Coyote Springs 2	**14**	7	102	7	7	7	6	6	6	7	7	7	7
Coyote Springs 2 duct burner	**1**	0	8	1	1	1	1	1	1	1	1	1	0
Kettle Falls	**5**	3	3	3	3	23	3	3	3	3	3	3	3
Kettle Falls CT	**1**	1	1	1	1	3	1	1	1	1	1	1	1
Northeast	**3**	3	3	3	3	3	3	3	3	3	3	3	3
Rathdrum	**20**	16	16	15	15	45	45	14	14	15	15	15	16
TOTAL MAINT AND FORCED OUTAGE	**79**	**61**	**163**	**64**	**63**	**156**	**90**	**59**	**59**	**60**	**60**	**61**	**61**
NET POSITION	**Annual**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Conditions	**(113)**	**(223)**	**(257)**	**(220)**	**45**	**200**	**308**	**(49)**	**(181)**	**(273)**	**(296)**	**(193)**	**(221)**
80% Confidence Interval	**(266)**	**(414)**	**(432)**	**(387)**	**(130)**	**32**	**124**	**(317)**	**(283)**	**(349)**	**(384)**	**(304)**	**(350)**
WNP-3 Obligation	**36**	48	48	48	48	0	48	0	0	48	48	48	48
WNP-3 Adjusted 80% CI Position	**(302)**	(461)	(480)	(435)	(178)	32	76	(317)	(283)	(397)	(431)	(352)	(397)

Table F.10
Monthly Loads & Resources Energy Forecast – 2012 (in aMW)

December 12, 2002 Version

Year 2012	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS													
Average Load	**1,233**	1,404	1,352	1,313	1,177	1,111	1,109	1,174	1,180	1,118	1,150	1,284	1,422
Potlatch Load	***52***	*52*	*52*	*52*	*52*	*52*	*52*	*52*	*52*	*52*	*52*	*52*	*52*
TOTAL LOADS	**1,285**	**1,456**	**1,404**	**1,365**	**1,229**	**1,163**	**1,161**	**1,226**	**1,232**	**1,170**	**1,201**	**1,336**	**1,474**
CONTRACT RIGHTS													
Black Creek Hydro	**1**	0	0	0	0	0	0	0	11	0	0	0	0
PGE Capacity Return	**48**	48	47	48	48	50	48	46	50	44	50	48	44
Small Power	**3**	3	3	4	5	4	4	4	2	2	2	3	3
Upriver	**9**	12	12	13	12	11	12	6	3	4	6	8	11
WNP-3	**48**	116	112	57	57	0	0	0	0	0	0	116	116
TOTAL CONTRACT RIGHTS	**109**	**180**	**175**	**123**	**122**	**65**	**64**	**57**	**66**	**49**	**58**	**175**	**174**
CONTRACT OBLIGATIONS													
Canadian Entitlement	**2**	2	2	2	2	2	2	2	2	2	2	2	2
Nichols Pumping net of PGE	**1**	1	1	1	1	1	1	1	1	1	1	1	1
PGE Capacity	**48**	48	47	48	48	50	48	46	50	44	50	48	44
TOTAL CONTRACT OBLIGATIONS	**51**	**51**	**50**	**51**	**51**	**53**	**51**	**49**	**53**	**47**	**53**	**51**	**47**
NET CONTRACT POSITION	**58**	**128**	**124**	**71**	**72**	**12**	**13**	**8**	**13**	**3**	**5**	**124**	**127**
HYDRO RESOURCES (Average Water)													
Spokane River	**123**	128	149	156	159	159	150	101	60	76	94	107	143
Clark Fork	**325**	247	261	227	357	603	644	394	297	147	150	262	313
Mid-Columbia	**29**	42	34	27	24	28	34	28	30	22	23	23	32
Sub-Total	**477**	416	444	410	540	790	828	523	387	245	267	391	488
THERMAL RESOURCES (Full Capability)													
Boulder Park	**25**	25	25	25	25	25	25	25	25	25	25	25	25
Colstrip	**222**	222	222	222	222	222	222	222	222	222	222	222	222
Coyote Springs 2	**132**	134	134	133	133	131	129	127	127	131	133	134	134
Coyote Springs 2 duct burner	**10**	10	10	10	10	10	10	10	10	10	10	10	10
Kettle Falls	**47**	47	47	47	47	47	47	47	47	47	47	47	47
Kettle Falls CT	**7**	7	7	7	7	7	7	7	7	7	7	7	7
Northeast	**53**	56	56	55	53	52	51	50	50	52	53	55	56
Rathdrum	**150**	157	156	153	150	147	145	142	143	146	150	154	156
Sub-Total	**645**	658	655	651	646	642	637	631	631	639	646	653	657
TOTAL RESOURCES	**1,123**	**1,074**	**1,099**	**1,061**	**1,187**	**1,431**	**1,465**	**1,153**	**1,018**	**884**	**913**	**1,044**	**1,145**
MAINTENANCE AND FORCED OUTAGE													
Boulder Park	**2**	1	1	4	4	1	1	1	1	1	1	1	1
Colstrip	**34**	31	31	31	31	74	31	31	31	31	31	31	31
Coyote Springs 2	**11**	7	7	7	7	63	6	6	6	7	7	7	7
Coyote Springs 2 duct burner	**1**	0	0	1	1	5	1	1	1	1	1	1	0
Kettle Falls	**5**	3	3	3	3	23	3	3	3	3	3	3	3
Kettle Falls CT	**1**	1	1	1	1	3	1	1	1	1	1	1	1
Northeast	**3**	3	3	3	3	3	3	3	3	3	3	3	3
Rathdrum	**20**	16	16	15	15	45	45	14	14	15	15	15	16
TOTAL MAINT AND FORCED OUTAGE	**76**	**61**	**61**	**64**	**63**	**216**	**90**	**59**	**59**	**60**	**60**	**61**	**61**
NET POSITION	**Annual**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Conditions	**(180)**	**(315)**	**(242)**	**(296)**	**(33)**	**64**	**227**	**(124)**	**(260)**	**(343)**	**(344)**	**(229)**	**(263)**
80% Confidence Interval	**(333)**	**(505)**	**(417)**	**(464)**	**(208)**	**(105)**	**43**	**(392)**	**(362)**	**(420)**	**(432)**	**(340)**	**(392)**
WNP-3 Obligation	**36**	48	48	48	48	0	48	0	0	48	48	48	48
WNP-3 Adjusted 80% CI Position	**(369)**	(553)	(464)	(512)	(256)	(105)	(4)	(392)	(362)	(467)	(480)	(388)	(440)

Table F.11
Monthly Loads & Resources Energy Forecast – 2013 (in aMW)

December 12, 2002 Version

Year 2013	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS													
Average Load	**1,272**	1,451	1,396	1,356	1,216	1,147	1,145	1,210	1,218	1,157	1,186	1,322	1,467
Potlatch Load	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*
TOTAL LOADS	**1,326**	**1,505**	**1,450**	**1,409**	**1,270**	**1,201**	**1,199**	**1,264**	**1,272**	**1,211**	**1,240**	**1,376**	**1,521**
CONTRACT RIGHTS													
Black Creek Hydro	**1**	0	0	0	0	0	0	0	11	0	0	0	0
PGE Capacity Return	**48**	48	49	48	48	50	48	46	50	44	50	48	44
Small Power	**3**	3	3	4	5	4	4	4	2	2	2	3	3
Upriver	**9**	12	13	13	12	11	12	6	3	4	6	8	11
WNP-3	**48**	116	116	57	57	0	0	0	0	0	0	116	116
TOTAL CONTRACT RIGHTS	**109**	**180**	**181**	**123**	**122**	**65**	**64**	**57**	**66**	**49**	**58**	**175**	**174**
CONTRACT OBLIGATIONS													
Canadian Entitlement	**2**	2	2	2	2	2	2	2	2	2	2	2	2
Nichols Pumping net of PGE	**1**	1	1	1	1	1	1	1	1	1	1	1	1
PGE Capacity	**48**	48	49	48	48	50	48	46	50	44	50	48	44
TOTAL CONTRACT OBLIGATIONS	**51**	**51**	**52**	**51**	**51**	**53**	**51**	**49**	**53**	**47**	**53**	**51**	**47**
NET CONTRACT POSITION	**58**	**128**	**129**	**71**	**72**	**12**	**13**	**8**	**13**	**3**	**5**	**124**	**127**
HYDRO RESOURCES (Average Water)													
Spokane River	**123**	128	149	156	159	159	150	101	60	76	94	107	143
Clark Fork	**325**	247	261	227	357	603	644	394	297	147	150	262	313
Mid-Columbia	**28**	40	33	26	24	27	33	28	29	21	22	22	31
Sub-Total	**477**	415	443	409	540	789	828	522	386	244	266	390	487
THERMAL RESOURCES (Full Capability)													
Boulder Park	**25**	25	25	25	25	25	25	25	25	25	25	25	25
Colstrip	**222**	222	222	222	222	222	222	222	222	222	222	222	222
Coyote Springs 2	**132**	134	134	133	133	131	129	127	127	131	133	134	134
Coyote Springs 2 duct burner	**10**	10	10	10	10	10	10	10	10	10	10	10	10
Kettle Falls	**47**	47	47	47	47	47	47	47	47	47	47	47	47
Kettle Falls CT	**7**	7	7	7	7	7	7	7	7	7	7	7	7
Northeast	**53**	56	56	55	53	52	51	50	50	52	53	55	56
Rathdrum	**150**	157	156	153	150	147	145	142	143	146	150	154	156
Sub-Total	**645**	658	655	651	646	642	637	631	631	639	646	653	657
TOTAL RESOURCES	**1,122**	**1,073**	**1,098**	**1,060**	**1,186**	**1,431**	**1,464**	**1,153**	**1,017**	**883**	**912**	**1,043**	**1,144**
MAINTENANCE AND FORCED OUTAGE													
Boulder Park	**2**	1	1	4	4	1	1	1	1	1	1	1	1
Colstrip	**34**	31	31	31	31	74	31	31	31	31	31	31	31
Coyote Springs 2	**11**	7	7	7	7	63	6	6	6	7	7	7	7
Coyote Springs 2 duct burner	**1**	0	0	1	1	5	1	1	1	1	1	1	0
Kettle Falls	**5**	3	3	3	3	23	3	3	3	3	3	3	3
Kettle Falls CT	**1**	1	1	1	1	3	1	1	1	1	1	1	1
Northeast	**3**	3	3	3	3	3	3	3	3	3	3	3	3
Rathdrum	**20**	16	16	15	15	45	45	14	14	15	15	15	16
TOTAL MAINT AND FORCED OUTAGE	**76**	**61**	**61**	**64**	**63**	**216**	**90**	**59**	**59**	**60**	**60**	**61**	**61**
NET POSITION	**Annual**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Conditions	**(222)**	**(365)**	**(285)**	**(342)**	**(74)**	**25**	**188**	**(163)**	**(300)**	**(384)**	**(383)**	**(270)**	**(311)**
80% Confidence Interval	**(375)**	**(556)**	**(459)**	**(509)**	**(250)**	**(143)**	**5**	**(431)**	**(402)**	**(461)**	**(471)**	**(381)**	**(440)**
WNP-3 Obligation	**36**	48	48	48	48	0	48	0	0	48	48	48	48
WNP-3 Adjusted 80% CI Position	**(411)**	(604)	(507)	(557)	(298)	(143)	(43)	(431)	(402)	(509)	(519)	(429)	(487)

Table F.12
Monthly Loads & Resources Energy Forecast – 2014 (in aMW)

December 12, 2002 Version

Year 2014	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS													
Average Load	**1,310**	1,496	1,438	1,396	1,253	1,181	1,179	1,244	1,254	1,193	1,221	1,359	1,509
Potlatch Load	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*
TOTAL LOADS	**1,364**	**1,550**	**1,492**	**1,450**	**1,307**	**1,235**	**1,232**	**1,298**	**1,307**	**1,247**	**1,275**	**1,412**	**1,563**
CONTRACT RIGHTS													
Black Creek Hydro	**1**	0	0	0	0	0	0	0	11	0	0	0	0
PGE Capacity Return	**48**	48	49	48	48	50	48	46	50	44	50	48	44
Small Power	**3**	3	3	4	5	4	4	4	2	2	2	3	3
Upriver	**9**	12	13	13	12	11	12	6	3	4	6	8	11
WNP-3	**48**	116	116	57	57	0	0	0	0	0	0	116	116
TOTAL CONTRACT RIGHTS	**109**	**180**	**181**	**123**	**122**	**65**	**64**	**57**	**66**	**49**	**58**	**175**	**174**
CONTRACT OBLIGATIONS													
Canadian Entitlement	**2**	2	2	2	2	2	2	2	2	2	2	2	2
Nichols Pumping net of PGE	**1**	1	1	1	1	1	1	1	1	1	1	1	1
PGE Capacity	**48**	48	49	48	48	50	48	46	50	44	50	48	44
TOTAL CONTRACT OBLIGATIONS	**51**	**51**	**52**	**51**	**51**	**53**	**51**	**49**	**53**	**47**	**53**	**51**	**47**
NET CONTRACT POSITION	**58**	**128**	**129**	**71**	**72**	**12**	**13**	**8**	**13**	**3**	**5**	**124**	**127**
HYDRO RESOURCES (Average Water)													
Spokane River	**123**	128	149	156	159	159	150	101	60	76	94	107	143
Clark Fork	**325**	247	261	227	357	603	644	394	297	147	150	262	313
Mid-Columbia	**27**	39	32	25	23	26	32	27	28	21	21	21	30
Sub-Total	**476**	414	442	408	539	788	827	521	385	243	265	390	486
THERMAL RESOURCES (Full Capability)													
Boulder Park	**25**	25	25	25	25	25	25	25	25	25	25	25	25
Colstrip	**222**	222	222	222	222	222	222	222	222	222	222	222	222
Coyote Springs 2	**132**	134	134	133	133	131	129	127	127	131	133	134	134
Coyote Springs 2 duct burner	**10**	10	10	10	10	10	10	10	10	10	10	10	10
Kettle Falls	**47**	47	47	47	47	47	47	47	47	47	47	47	47
Kettle Falls CT	**7**	7	7	7	7	7	7	7	7	7	7	7	7
Northeast	**53**	56	56	55	53	52	51	50	50	52	53	55	56
Rathdrum	**150**	157	156	153	150	147	145	142	143	146	150	154	156
Sub-Total	**645**	658	655	651	646	642	637	631	631	639	646	653	657
TOTAL RESOURCES	**1,121**	**1,072**	**1,097**	**1,059**	**1,186**	**1,430**	**1,463**	**1,152**	**1,017**	**882**	**912**	**1,043**	**1,143**
MAINTENANCE AND FORCED OUTAGE													
Boulder Park	**2**	1	1	4	4	1	1	1	1	1	1	1	1
Colstrip	**34**	31	31	31	31	74	31	31	31	31	31	31	31
Coyote Springs 2	**14**	7	102	7	7	7	6	6	6	7	7	7	7
Coyote Springs 2 duct burner	**1**	0	8	1	1	1	1	1	1	1	1	1	0
Kettle Falls	**5**	3	3	3	3	23	3	3	3	3	3	3	3
Kettle Falls CT	**1**	1	1	1	1	3	1	1	1	1	1	1	1
Northeast	**3**	3	3	3	3	3	3	3	3	3	3	3	3
Rathdrum	**20**	16	16	15	15	45	45	14	14	15	15	15	16
TOTAL MAINT AND FORCED OUTAGE	**79**	**61**	**163**	**64**	**63**	**156**	**90**	**59**	**59**	**60**	**60**	**61**	**61**
NET POSITION	**Annual**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Conditions	**(263)**	**(412)**	**(430)**	**(383)**	**(112)**	**52**	**154**	**(198)**	**(337)**	**(421)**	**(419)**	**(307)**	**(354)**
80% Confidence Interval	**(416)**	**(602)**	**(604)**	**(550)**	**(287)**	**(117)**	**(30)**	**(466)**	**(439)**	**(498)**	**(507)**	**(418)**	**(483)**
WNP-3 Obligation	**36**	48	48	48	48	0	48	0	0	48	48	48	48
WNP-3 Adjusted 80% CI Position	**(452)**	(650)	(652)	(598)	(335)	(117)	(77)	(466)	(439)	(546)	(555)	(466)	(531)

Table F.13
Monthly Loads & Resources Energy Forecast – 2015 (in aMW)

December 12, 2002 Version

Year 2015	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS													
Average Load	**1,358**	1,555	1,492	1,447	1,300	1,225	1,222	1,288	1,300	1,240	1,266	1,405	1,564
Potlatch Load	*56*	*56*	*56*	*56*	*56*	*56*	*56*	*56*	*56*	*56*	*56*	*56*	*56*
TOTAL LOADS	**1,414**	**1,611**	**1,548**	**1,503**	**1,356**	**1,280**	**1,278**	**1,344**	**1,356**	**1,296**	**1,322**	**1,461**	**1,620**
CONTRACT RIGHTS													
Black Creek Hydro	**1**	0	0	0	0	0	0	0	11	0	0	0	0
PGE Capacity Return	**48**	48	49	48	48	50	48	46	50	44	50	48	44
Small Power	**3**	3	3	4	5	4	4	4	2	2	2	3	3
Upriver	**9**	12	13	13	12	11	12	6	3	4	6	8	11
WNP-3	**48**	116	116	57	57	0	0	0	0	0	0	116	116
TOTAL CONTRACT RIGHTS	**109**	**180**	**181**	**123**	**122**	**65**	**64**	**57**	**66**	**49**	**58**	**175**	**174**
CONTRACT OBLIGATIONS													
Canadian Entitlement	**2**	2	2	2	2	2	2	2	2	2	2	2	2
Nichols Pumping net of PGE	**1**	1	1	1	1	1	1	1	1	1	1	1	1
PGE Capacity	**48**	48	49	48	48	50	48	46	50	44	50	48	44
TOTAL CONTRACT OBLIGATIONS	**51**	**51**	**52**	**51**	**51**	**53**	**51**	**49**	**53**	**46**	**53**	**51**	**47**
NET CONTRACT POSITION	**58**	**128**	**129**	**72**	**72**	**12**	**13**	**8**	**13**	**3**	**5**	**124**	**127**
HYDRO RESOURCES (Average Water)													
Spokane River	**123**	128	149	156	159	159	150	101	60	76	94	107	143
Clark Fork	**325**	247	261	227	357	603	644	394	297	147	150	262	313
Mid-Columbia	**26**	38	31	25	23	26	31	26	27	20	20	20	29
Sub-Total	**475**	413	441	407	539	788	826	521	384	243	265	389	485
THERMAL RESOURCES (Full Capability)													
Boulder Park	**25**	25	25	25	25	25	25	25	25	25	25	25	25
Colstrip	**222**	222	222	222	222	222	222	222	222	222	222	222	222
Coyote Springs 2	**132**	134	134	133	133	131	129	127	127	131	133	134	134
Coyote Springs 2 duct burner	**10**	10	10	10	10	10	10	10	10	10	10	10	10
Kettle Falls	**47**	47	47	47	47	47	47	47	47	47	47	47	47
Kettle Falls CT	**7**	7	7	7	7	7	7	7	7	7	7	7	7
Northeast	**53**	56	56	55	53	52	51	50	50	52	53	55	56
Rathdrum	**150**	157	156	153	150	147	145	142	143	146	150	154	156
Sub-Total	**645**	658	655	651	646	642	637	631	631	639	646	653	657
TOTAL RESOURCES	**1,120**	**1,070**	**1,096**	**1,058**	**1,185**	**1,429**	**1,462**	**1,151**	**1,016**	**882**	**911**	**1,042**	**1,142**
MAINTENANCE AND FORCED OUTAGE													
Boulder Park	**2**	1	1	4	4	1	1	1	1	1	1	1	1
Colstrip	**34**	31	31	31	31	74	31	31	31	31	31	31	31
Coyote Springs 2	**11**	7	7	7	7	63	6	6	6	7	7	7	7
Coyote Springs 2 duct burner	**1**	0	0	1	1	5	1	1	1	1	1	1	0
Kettle Falls	**5**	3	3	3	3	23	3	3	3	3	3	3	3
Kettle Falls CT	**1**	1	1	1	1	3	1	1	1	1	1	1	1
Northeast	**3**	3	3	3	3	3	3	3	3	3	3	3	3
Rathdrum	**20**	16	16	15	15	45	45	14	14	15	15	15	16
TOTAL MAINT AND FORCED OUTAGE	**76**	**61**	**61**	**64**	**63**	**216**	**90**	**59**	**59**	**60**	**60**	**61**	**61**
NET POSITION	**Annual**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Conditions	**(312)**	**(473)**	**(385)**	**(437)**	**(162)**	**(55)**	**107**	**(244)**	**(386)**	**(471)**	**(466)**	**(356)**	**(412)**
80% Confidence Interval	**(465)**	**(664)**	**(559)**	**(605)**	**(337)**	**(224)**	**(76)**	**(512)**	**(488)**	**(548)**	**(554)**	**(468)**	**(541)**
WNP-3 Obligation	**36**	48	48	48	48	0	48	0	0	48	48	48	48
WNP-3 Adjusted 80% CI Position	**(501)**	(711)	(607)	(652)	(385)	(224)	(124)	(512)	(488)	(596)	(602)	(516)	(588)

Table F.14
Monthly Loads & Resources Energy Forecast – 2016 (in aMW)

December 12, 2002 Version

Year 2016	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS													
Average Load	**1,409**	1,615	1,548	1,501	1,350	1,270	1,268	1,334	1,348	1,289	1,313	1,454	1,621
Potlatch Load	***56***	*56*	*56*	*56*	*56*	*56*	*56*	*56*	*56*	*56*	*56*	*56*	*56*
TOTAL LOADS	**1,465**	**1,671**	**1,604**	**1,557**	**1,405**	**1,326**	**1,323**	**1,390**	**1,404**	**1,345**	**1,368**	**1,510**	**1,677**
CONTRACT RIGHTS													
Black Creek Hydro	**1**	0	0	0	0	0	0	0	11	0	0	0	0
PGE Capacity Return	**48**	48	47	48	48	50	48	46	50	44	50	48	44
Small Power	**3**	3	3	4	5	4	4	4	2	2	2	3	3
Upriver	**9**	12	12	13	12	11	12	6	3	4	6	8	11
WNP-3	**48**	116	112	57	57	0	0	0	0	0	0	116	116
TOTAL CONTRACT RIGHTS	**109**	**180**	**175**	**123**	**122**	**65**	**64**	**57**	**66**	**49**	**58**	**175**	**174**
CONTRACT OBLIGATIONS													
Canadian Entitlement	**2**	2	2	2	2	2	2	2	2	2	2	2	2
Nichols Pumping net of PGE	**1**	1	1	1	1	1	1	1	1	1	1	1	1
PGE Capacity	**48**	48	47	48	48	50	48	46	50	44	50	48	44
TOTAL CONTRACT OBLIGATIONS	**51**	**51**	**50**	**51**	**51**	**53**	**51**	**49**	**53**	**46**	**53**	**51**	**47**
NET CONTRACT POSITION	**58**	**128**	**124**	**72**	**72**	**12**	**13**	**8**	**13**	**3**	**5**	**124**	**127**
HYDRO RESOURCES (Average Water)													
Spokane River	**123**	128	149	156	159	159	150	101	60	76	94	107	143
Clark Fork	**325**	247	261	227	357	603	644	394	297	147	150	262	313
Mid-Columbia	**26**	37	30	24	22	25	31	25	27	19	20	20	28
Sub-Total	**474**	411	440	406	538	787	825	520	384	242	264	388	484
THERMAL RESOURCES (Full Capability)													
Boulder Park	**25**	25	25	25	25	25	25	25	25	25	25	25	25
Colstrip	**222**	222	222	222	222	222	222	222	222	222	222	222	222
Coyote Springs 2	**132**	134	134	133	133	131	129	127	127	131	133	134	134
Coyote Springs 2 duct burner	**10**	10	10	10	10	10	10	10	10	10	10	10	10
Kettle Falls	**47**	47	47	47	47	47	47	47	47	47	47	47	47
Kettle Falls CT	**7**	7	7	7	7	7	7	7	7	7	7	7	7
Northeast	**53**	56	56	55	53	52	51	50	50	52	53	55	56
Rathdrum	**150**	157	156	153	150	147	145	142	143	146	150	154	156
Sub-Total	**645**	658	655	651	646	642	637	631	631	639	646	653	657
TOTAL RESOURCES	**1,119**	**1,069**	**1,095**	**1,057**	**1,185**	**1,429**	**1,462**	**1,150**	**1,015**	**881**	**910**	**1,041**	**1,141**
MAINTENANCE AND FORCED OUTAGE													
Boulder Park	**2**	1	1	4	4	1	1	1	1	1	1	1	1
Colstrip	**34**	31	31	31	31	74	31	31	31	31	31	31	31
Coyote Springs 2	**11**	7	7	7	7	63	6	6	6	7	7	7	7
Coyote Springs 2 duct burner	**1**	0	0	1	1	5	1	1	1	1	1	1	0
Kettle Falls	**5**	3	3	3	3	23	3	3	3	3	3	3	3
Kettle Falls CT	**1**	1	1	1	1	3	1	1	1	1	1	1	1
Northeast	**3**	3	3	3	3	3	3	3	3	3	3	3	3
Rathdrum	**20**	16	16	15	15	45	45	14	14	15	15	15	16
TOTAL MAINT AND FORCED OUTAGE	**76**	**61**	**61**	**64**	**63**	**216**	**90**	**59**	**59**	**60**	**60**	**61**	**61**
NET POSITION	**Annual**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Conditions	**(364)**	**(534)**	**(446)**	**(491)**	**(212)**	**(101)**	**61**	**(291)**	**(434)**	**(521)**	**(514)**	**(405)**	**(469)**
80% Confidence Interval	**(517)**	**(725)**	**(621)**	**(659)**	**(387)**	**(270)**	**(122)**	**(559)**	**(536)**	**(597)**	**(602)**	**(517)**	**(598)**
WNP-3 Obligation	**36**	48	48	48	48	0	48	0	0	48	48	48	48
WNP-3 Adjusted 80% CI Position	**(552)**	(773)	(668)	(707)	(435)	(270)	(170)	(559)	(536)	(645)	(649)	(565)	(646)

Table F.15
Monthly Loads & Resources Energy Forecast – 2017 (in aMW)

December 12, 2002 Version

Year 2017	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS													
Average Load	**1,459**	1,676	1,605	1,555	1,399	1,315	1,313	1,380	1,396	1,338	1,359	1,503	1,678
Potlatch Load	***58***	*58*	*58*	*58*	*58*	*58*	*58*	*58*	*58*	*58*	*58*	*58*	*58*
TOTAL LOADS	**1,517**	**1,734**	**1,663**	**1,613**	**1,457**	**1,373**	**1,371**	**1,438**	**1,454**	**1,396**	**1,417**	**1,561**	**1,736**
CONTRACT RIGHTS													
Black Creek Hydro	**1**	0	0	0	0	0	0	0	11	0	0	0	0
Small Power	**3**	3	3	4	5	4	4	4	2	2	2	3	3
Upriver	**9**	12	13	13	12	11	12	6	3	4	6	8	11
WNP-3	**48**	116	116	57	57	0	0	0	0	0	0	116	116
TOTAL CONTRACT RIGHTS	**61**	**131**	**132**	**74**	**75**	**15**	**16**	**10**	**16**	**6**	**8**	**127**	**130**
CONTRACT OBLIGATIONS													
Canadian Entitlement	**2**	2	2	2	2	2	2	2	2	2	2	2	2
Nichols Pumping net of PGE	**1**	1	1	1	1	1	1	1	1	1	1	1	1
TOTAL CONTRACT OBLIGATIONS	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**
NET CONTRACT POSITION	**58**	**129**	**129**	**72**	**72**	**12**	**13**	**8**	**13**	**3**	**5**	**124**	**127**
HYDRO RESOURCES (Average Water)													
Spokane River	**123**	128	149	156	159	159	150	101	60	76	94	107	143
Clark Fork	**325**	247	261	227	357	603	644	394	297	147	150	262	313
Mid-Columbia	**25**	36	29	23	22	25	30	24	26	18	19	19	27
Sub-Total	**473**	410	439	405	538	787	824	519	383	241	263	387	483
THERMAL RESOURCES (Full Capability)													
Boulder Park	**25**	25	25	25	25	25	25	25	25	25	25	25	25
Colstrip	**222**	222	222	222	222	222	222	222	222	222	222	222	222
Coyote Springs 2	**132**	134	134	133	133	131	129	127	127	131	133	134	134
Coyote Springs 2 duct burner	**10**	10	10	10	10	10	10	10	10	10	10	10	10
Kettle Falls	**47**	47	47	47	47	47	47	47	47	47	47	47	47
Kettle Falls CT	**7**	7	7	7	7	7	7	7	7	7	7	7	7
Northeast	**53**	56	56	55	53	52	51	50	50	52	53	55	56
Rathdrum	**150**	157	156	153	150	147	145	142	143	146	150	154	156
Sub-Total	**645**	658	655	651	646	642	637	631	631	639	646	653	657
TOTAL RESOURCES	**1,119**	**1,068**	**1,094**	**1,056**	**1,184**	**1,428**	**1,461**	**1,150**	**1,014**	**880**	**909**	**1,040**	**1,140**
MAINTENANCE AND FORCED OUTAGE													
Boulder Park	**2**	1	1	4	4	1	1	1	1	1	1	1	1
Colstrip	**34**	31	31	31	31	74	31	31	31	31	31	31	31
Coyote Springs 2	**14**	7	102	7	7	7	6	6	6	7	7	7	7
Coyote Springs 2 duct burner	**1**	0	8	1	1	1	1	1	1	1	1	1	0
Kettle Falls	**5**	3	3	3	3	23	3	3	3	3	3	3	3
Kettle Falls CT	**1**	1	1	1	1	3	1	1	1	1	1	1	1
Northeast	**3**	3	3	3	3	3	3	3	3	3	3	3	3
Rathdrum	**20**	16	16	15	15	45	45	14	14	15	15	15	16
TOTAL MAINT AND FORCED OUTAGE	**79**	**61**	**163**	**64**	**63**	**156**	**90**	**59**	**59**	**60**	**60**	**61**	**61**
NET POSITION	**Annual**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Conditions	**(419)**	**(598)**	**(603)**	**(548)**	**(264)**	**(88)**	**13**	**(339)**	**(485)**	**(573)**	**(563)**	**(457)**	**(530)**
80% Confidence Interval	**(572)**	**(789)**	**(778)**	**(716)**	**(440)**	**(257)**	**(171)**	**(607)**	**(587)**	**(649)**	**(651)**	**(569)**	**(659)**
WNP-3 Obligation	**36**	48	48	48	48	0	48	0	0	48	48	48	48
WNP-3 Adjusted 80% CI Position	**(608)**	(837)	(826)	(764)	(487)	(257)	(218)	(607)	(587)	(697)	(699)	(617)	(706)

Table F.16
Monthly Loads & Resources Energy Forecast – 2018 (in aMW)

December 12, 2002 Version

Year 2018	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS													
Average Load	**1,512**	1,738	1,663	1,611	1,450	1,362	1,360	1,427	1,446	1,389	1,408	1,553	1,737
Potlatch Load	*58*	*58*	*58*	*58*	*58*	*58*	*58*	*58*	*58*	*58*	*58*	*58*	*58*
TOTAL LOADS	**1,569**	**1,796**	**1,721**	**1,669**	**1,508**	**1,420**	**1,418**	**1,485**	**1,503**	**1,447**	**1,466**	**1,611**	**1,795**
CONTRACT RIGHTS													
Black Creek Hydro	**1**	0	0	0	0	0	0	0	11	0	0	0	0
Small Power	**3**	3	3	4	5	4	4	4	2	2	2	3	3
Upriver	**9**	12	13	13	12	11	12	6	3	4	6	8	11
WNP-3	**48**	116	116	57	57	0	0	0	0	0	0	116	116
TOTAL CONTRACT RIGHTS	**61**	**131**	**132**	**74**	**75**	**15**	**16**	**10**	**16**	**6**	**8**	**127**	**130**
CONTRACT OBLIGATIONS													
Canadian Entitlement	**1**	2	2	2	2	2	2	2	2	2	1	1	1
Nichols Pumping net of PGE	**1**	1	1	1	1	1	1	1	1	1	1	1	1
TOTAL CONTRACT OBLIGATIONS	**2**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**2**	**2**	**2**
NET CONTRACT POSITION	**59**	**129**	**129**	**72**	**72**	**12**	**13**	**8**	**13**	**3**	**6**	**125**	**128**
HYDRO RESOURCES (Average Water)													
Spokane River	**123**	128	149	156	159	159	150	101	60	76	94	107	143
Clark Fork	**325**	247	261	227	357	603	644	394	297	147	150	262	313
Mid-Columbia	**22**	34	28	22	21	24	29	24	25	18	13	13	17
Sub-Total	**471**	409	438	405	537	786	824	518	382	240	257	381	473
THERMAL RESOURCES (Full Capability)													
Boulder Park	**25**	25	25	25	25	25	25	25	25	25	25	25	25
Colstrip	**222**	222	222	222	222	222	222	222	222	222	222	222	222
Coyote Springs 2	**132**	134	134	133	133	131	129	127	127	131	133	134	134
Coyote Springs 2 duct burner	**10**	10	10	10	10	10	10	10	10	10	10	10	10
Kettle Falls	**47**	47	47	47	47	47	47	47	47	47	47	47	47
Kettle Falls CT	**7**	7	7	7	7	7	7	7	7	7	7	7	7
Northeast	**53**	56	56	55	53	52	51	50	50	52	53	55	56
Rathdrum	**150**	157	156	153	150	147	145	142	143	146	150	154	156
Sub-Total	**645**	658	655	651	646	642	637	631	631	639	646	653	657
TOTAL RESOURCES	**1,116**	**1,067**	**1,093**	**1,056**	**1,183**	**1,427**	**1,460**	**1,149**	**1,013**	**879**	**903**	**1,034**	**1,130**
MAINTENANCE AND FORCED OUTAGE													
Boulder Park	**2**	1	1	4	4	1	1	1	1	1	1	1	1
Colstrip	**34**	31	31	31	31	74	31	31	31	31	31	31	31
Coyote Springs 2	**11**	7	7	7	7	63	6	6	6	7	7	7	7
Coyote Springs 2 duct burner	**1**	0	0	1	1	5	1	1	1	1	1	1	0
Kettle Falls	**5**	3	3	3	3	23	3	3	3	3	3	3	3
Kettle Falls CT	**1**	1	1	1	1	3	1	1	1	1	1	1	1
Northeast	**3**	3	3	3	3	3	3	3	3	3	3	3	3
Rathdrum	**20**	16	16	15	15	45	45	14	14	15	15	15	16
TOTAL MAINT AND FORCED OUTAGE	**76**	**61**	**61**	**64**	**63**	**216**	**90**	**59**	**59**	**60**	**60**	**61**	**61**
NET POSITION	**Annual**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Conditions	**(471)**	**(662)**	**(560)**	**(605)**	**(316)**	**(196)**	**(35)**	**(387)**	**(536)**	**(624)**	**(617)**	**(512)**	**(598)**
80% Confidence Interval	**(624)**	**(853)**	**(735)**	**(772)**	**(491)**	**(365)**	**(218)**	**(655)**	**(638)**	**(701)**	**(705)**	**(624)**	**(727)**
WNP-3 Obligation	**36**	48	48	48	48	0	48	0	0	48	48	48	48
WNP-3 Adjusted 80% CI Position	**(660)**	(900)	(782)	(820)	(539)	(365)	(266)	(655)	(638)	(748)	(752)	(672)	(774)

Table F.17
Monthly Loads & Resources Energy Forecast – 2019 (in aMW)

December 12, 2002 Version

Year 2019	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS													
Average Load	**1,560**	1,797	1,717	1,663	1,498	1,406	1,404	1,471	1,492	1,436	1,453	1,600	1,792
Potlatch Load	***60***	*60*	*60*	*60*	*60*	*60*	*60*	*60*	*60*	*60*	*60*	*60*	*60*
TOTAL LOADS	**1,620**	**1,857**	**1,777**	**1,722**	**1,558**	**1,466**	**1,464**	**1,531**	**1,552**	**1,496**	**1,513**	**1,660**	**1,852**
CONTRACT RIGHTS													
Black Creek Hydro	**1**	0	0	0	0	0	0	0	11	0	0	0	0
Small Power	**3**	3	3	4	5	4	4	4	2	2	2	3	3
Upriver	**9**	12	13	13	12	11	12	6	3	4	6	8	11
WNP-3	**28**	116	116	57	57	0	0	0	0	0	0	0	0
TOTAL CONTRACT RIGHTS	**42**	**131**	**132**	**74**	**75**	**15**	**16**	**10**	**16**	**6**	**8**	**11**	**14**
CONTRACT OBLIGATIONS													
Canadian Entitlement	**1**	1	1	1	1	1	1	1	1	1	1	1	1
Nichols Pumping net of PGE	**1**	1	1	1	1	1	1	1	1	1	1	1	1
TOTAL CONTRACT OBLIGATIONS	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**
NET CONTRACT POSITION	**40**	**130**	**130**	**73**	**73**	**13**	**14**	**9**	**14**	**4**	**6**	**9**	**13**
HYDRO RESOURCES (Average Water)													
Spokane River	**123**	128	149	156	159	159	150	101	60	76	94	107	143
Clark Fork	**325**	247	261	227	357	603	644	394	297	147	150	262	313
Mid-Columbia	**13**	19	16	14	9	10	13	12	13	12	12	12	16
Sub-Total	**462**	393	426	396	525	772	807	507	370	234	256	381	472
THERMAL RESOURCES (Full Capability)													
Boulder Park	**25**	25	25	25	25	25	25	25	25	25	25	25	25
Colstrip	**222**	222	222	222	222	222	222	222	222	222	222	222	222
Coyote Springs 2	**132**	134	134	133	133	131	129	127	127	131	133	134	134
Coyote Springs 2 duct burner	**10**	10	10	10	10	10	10	10	10	10	10	10	10
Kettle Falls	**47**	47	47	47	47	47	47	47	47	47	47	47	47
Kettle Falls CT	**7**	7	7	7	7	7	7	7	7	7	7	7	7
Northeast	**53**	56	56	55	53	52	51	50	50	52	53	55	56
Rathdrum	**150**	157	156	153	150	147	145	142	143	146	150	154	156
Sub-Total	**645**	658	655	651	646	642	637	631	631	639	646	653	657
TOTAL RESOURCES	**1,107**	**1,051**	**1,081**	**1,047**	**1,172**	**1,414**	**1,444**	**1,137**	**1,001**	**874**	**902**	**1,034**	**1,129**
MAINTENANCE AND FORCED OUTAGE													
Boulder Park	**2**	1	1	4	4	1	1	1	1	1	1	1	1
Colstrip	**34**	31	31	31	31	74	31	31	31	31	31	31	31
Coyote Springs 2	**11**	7	7	7	7	63	6	6	6	7	7	7	7
Coyote Springs 2 duct burner	**1**	0	0	1	1	5	1	1	1	1	1	1	0
Kettle Falls	**5**	3	3	3	3	23	3	3	3	3	3	3	3
Kettle Falls CT	**1**	1	1	1	1	3	1	1	1	1	1	1	1
Northeast	**3**	3	3	3	3	3	3	3	3	3	3	3	3
Rathdrum	**20**	16	16	15	15	45	45	14	14	15	15	15	16
TOTAL MAINT AND FORCED OUTAGE	**76**	**61**	**61**	**64**	**63**	**216**	**90**	**59**	**59**	**60**	**60**	**61**	**61**
NET POSITION	**Annual**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Conditions	**(549)**	**(737)**	**(627)**	**(666)**	**(376)**	**(255)**	**(96)**	**(444)**	**(596)**	**(678)**	**(664)**	**(678)**	**(771)**
80% Confidence Interval	**(702)**	**(928)**	**(801)**	**(834)**	**(552)**	**(424)**	**(280)**	**(712)**	**(697)**	**(755)**	**(752)**	**(790)**	**(900)**
WNP-3 Obligation	**20**	48	48	48	48	0	48	0	0	0	0	0	0
WNP-3 Adjusted 80% CI Position	**(722)**	(976)	(849)	(881)	(600)	(424)	(327)	(712)	(697)	(755)	(752)	(790)	(900)

Table F.18
Monthly Loads & Resources Energy Forecast – 2020 (in aMW)

December 12, 2002 Version

Year 2020	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS													
Average Load	**1,611**	1,857	1,773	1,716	1,547	1,451	1,449	1,517	1,540	1,485	1,499	1,649	1,848
Potlatch Load	***60***	*60*	*60*	*60*	*60*	*60*	*60*	*60*	*60*	*60*	*60*	*60*	*60*
TOTAL LOADS	**1,671**	**1,917**	**1,833**	**1,776**	**1,607**	**1,511**	**1,509**	**1,577**	**1,600**	**1,545**	**1,559**	**1,708**	**1,908**
CONTRACT RIGHTS													
Black Creek Hydro	**1**	0	0	0	0	0	0	0	11	0	0	0	0
Small Power	**3**	3	3	4	5	4	4	4	2	2	2	3	3
Upriver	**9**	12	12	13	12	11	12	6	3	4	6	8	11
TOTAL CONTRACT RIGHTS	**13**	**15**	**15**	**17**	**17**	**15**	**16**	**10**	**16**	**6**	**8**	**11**	**14**
CONTRACT OBLIGATIONS													
Canadian Entitlement	**1**	1	1	1	1	1	1	1	1	1	1	1	1
Nichols Pumping net of PGE	**1**	1	1	1	1	1	1	1	1	1	1	1	1
TOTAL CONTRACT OBLIGATIONS	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**
NET CONTRACT POSITION	**12**	**14**	**14**	**16**	**16**	**13**	**14**	**9**	**14**	**4**	**6**	**9**	**13**
HYDRO RESOURCES (Average Water)													
Spokane River	**123**	128	149	156	159	159	150	101	60	76	94	107	143
Clark Fork	**325**	247	261	227	357	603	644	394	297	147	150	262	313
Mid-Columbia	**12**	18	15	13	9	10	12	12	12	11	11	11	15
Sub-Total	**461**	392	425	396	525	772	807	506	369	234	255	380	471
THERMAL RESOURCES (Full Capability)													
Boulder Park	**25**	25	25	25	25	25	25	25	25	25	25	25	25
Colstrip	**222**	222	222	222	222	222	222	222	222	222	222	222	222
Coyote Springs 2	**132**	134	134	133	133	131	129	127	127	131	133	134	134
Coyote Springs 2 duct burner	**10**	10	10	10	10	10	10	10	10	10	10	10	10
Kettle Falls	**47**	47	47	47	47	47	47	47	47	47	47	47	47
Kettle Falls CT	**7**	7	7	7	7	7	7	7	7	7	7	7	7
Northeast	**53**	56	56	55	53	52	51	50	50	52	53	55	56
Rathdrum	**150**	157	156	153	150	147	145	142	143	146	150	154	156
Sub-Total	**645**	658	655	651	646	642	637	631	631	639	646	653	657
TOTAL RESOURCES	**1,106**	**1,050**	**1,080**	**1,047**	**1,171**	**1,413**	**1,443**	**1,137**	**1,000**	**873**	**902**	**1,033**	**1,128**
MAINTENANCE AND FORCED OUTAGE													
Boulder Park	**2**	1	1	4	4	1	1	1	1	1	1	1	1
Colstrip	**34**	31	31	31	31	74	31	31	31	31	31	31	31
Coyote Springs 2	**14**	7	99	7	7	7	6	6	6	7	7	7	7
Coyote Springs 2 duct burner	**1**	0	7	1	1	1	1	1	1	1	1	1	0
Kettle Falls	**5**	3	3	3	3	23	3	3	3	3	3	3	3
Kettle Falls CT	**1**	1	1	1	1	3	1	1	1	1	1	1	1
Northeast	**3**	3	3	3	3	3	3	3	3	3	3	3	3
Rathdrum	**20**	16	16	15	15	45	45	14	14	15	15	15	16
TOTAL MAINT AND FORCED OUTAGE	**79**	**61**	**160**	**64**	**63**	**156**	**90**	**59**	**59**	**60**	**60**	**61**	**61**
NET POSITION	**Annual**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Conditions	**(632)**	**(914)**	**(899)**	**(777)**	**(483)**	**(240)**	**(142)**	**(490)**	**(644)**	**(728)**	**(712)**	**(727)**	**(829)**
80% Confidence Interval	**(785)**	**(1,105)**	**(1,073)**	**(945)**	**(659)**	**(408)**	**(326)**	**(758)**	**(746)**	**(804)**	**(800)**	**(839)**	**(958)**

Table F.19
Monthly Loads & Resources Energy Forecast – 2021 (in aMW)

December 12, 2002 Version

Year 2021	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS													
Average Load	**1,669**	1,927	1,838	1,778	1,605	1,503	1,502	1,570	1,595	1,542	1,553	1,705	1,914
Potlatch Load	***62***	*62*	*62*	*62*	*62*	*62*	*62*	*62*	*62*	*62*	*62*	*62*	*62*
TOTAL LOADS	**1,731**	**1,989**	**1,900**	**1,840**	**1,667**	**1,565**	**1,564**	**1,632**	**1,657**	**1,603**	**1,615**	**1,767**	**1,976**
CONTRACT RIGHTS													
Black Creek Hydro	**1**	0	0	0	0	0	0	0	11	0	0	0	0
Small Power	**3**	3	3	4	5	4	4	4	2	2	2	3	3
Upriver	**9**	12	13	13	12	11	12	6	3	4	6	8	11
TOTAL CONTRACT RIGHTS	**13**	**15**	**16**	**17**	**17**	**15**	**16**	**10**	**16**	**6**	**8**	**11**	**14**
CONTRACT OBLIGATIONS													
Canadian Entitlement	**1**	1	1	1	1	1	1	1	1	1	1	1	1
Nichols Pumping net of PGE	**1**	1	1	1	1	1	1	1	1	1	1	1	1
TOTAL CONTRACT OBLIGATIONS	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**
NET CONTRACT POSITION	**12**	**14**	**14**	**16**	**16**	**13**	**14**	**9**	**14**	**4**	**6**	**9**	**13**
HYDRO RESOURCES (Average Water)													
Spokane River	**123**	128	149	156	159	159	150	101	60	76	94	107	143
Clark Fork	**325**	247	261	227	357	603	644	394	297	147	150	262	313
Mid-Columbia	**11**	16	14	12	8	9	11	11	11	10	10	10	14
Sub-Total	**460**	391	424	395	524	771	806	505	368	233	255	379	470
THERMAL RESOURCES (Full Capability)													
Boulder Park	**25**	25	25	25	25	25	25	25	25	25	25	25	25
Colstrip	**222**	222	222	222	222	222	222	222	222	222	222	222	222
Coyote Springs 2	**132**	134	134	133	133	131	129	127	127	131	133	134	134
Coyote Springs 2 duct burner	**10**	10	10	10	10	10	10	10	10	10	10	10	10
Kettle Falls	**47**	47	47	47	47	47	47	47	47	47	47	47	47
Kettle Falls CT	**7**	7	7	7	7	7	7	7	7	7	7	7	7
Northeast	**53**	56	56	55	53	52	51	50	50	52	53	55	56
Rathdrum	**150**	157	156	153	150	147	145	142	143	146	150	154	156
Sub-Total	**645**	658	655	651	646	642	637	631	631	639	646	653	657
TOTAL RESOURCES	**1,105**	**1,049**	**1,079**	**1,046**	**1,170**	**1,413**	**1,442**	**1,136**	**999**	**872**	**901**	**1,032**	**1,127**
MAINTENANCE AND FORCED OUTAGE													
Boulder Park	**2**	1	1	4	4	1	1	1	1	1	1	1	1
Colstrip	**34**	31	31	31	31	74	31	31	31	31	31	31	31
Coyote Springs 2	**11**	7	7	7	7	63	6	6	6	7	7	7	7
Coyote Springs 2 duct burner	**1**	0	0	1	1	5	1	1	1	1	1	1	0
Kettle Falls	**5**	3	3	3	3	23	3	3	3	3	3	3	3
Kettle Falls CT	**1**	1	1	1	1	3	1	1	1	1	1	1	1
Northeast	**3**	3	3	3	3	3	3	3	3	3	3	3	3
Rathdrum	**20**	16	16	15	15	45	45	14	14	15	15	15	16
TOTAL MAINT AND FORCED OUTAGE	**76**	**61**	**61**	**64**	**63**	**216**	**90**	**59**	**59**	**60**	**60**	**61**	**61**
NET POSITION	**Annual**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Conditions	**(690)**	**(988)**	**(868)**	**(843)**	**(543)**	**(356)**	**(197)**	**(546)**	**(703)**	**(787)**	**(768)**	**(786)**	**(898)**
80% Confidence Interval	**(843)**	**(1,178)**	**(1,042)**	**(1,010)**	**(719)**	**(524)**	**(381)**	**(814)**	**(804)**	**(864)**	**(856)**	**(898)**	**(1,027)**

Table F.20
Monthly Loads & Resources Energy Forecast – 2022 (in aMW)

December 12, 2002 Version

Year 2022	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS													
Average Load	**1,732**	2,002	1,908	1,845	1,666	1,560	1,558	1,627	1,655	1,602	1,611	1,765	1,985
Potlatch Load	***62***	*62*	*62*	*62*	*62*	*62*	*62*	*62*	*62*	*62*	*62*	*62*	*62*
TOTAL LOADS	**1,793**	**2,064**	**1,970**	**1,907**	**1,728**	**1,621**	**1,620**	**1,688**	**1,717**	**1,664**	**1,673**	**1,827**	**2,047**
CONTRACT RIGHTS													
Black Creek Hydro	**1**	0	0	0	0	0	0	0	11	0	0	0	0
Small Power	**3**	3	3	4	5	4	4	4	2	2	2	3	3
Upriver	**9**	12	13	13	12	11	12	6	3	4	6	8	11
TOTAL CONTRACT RIGHTS	**13**	**15**	**16**	**17**	**17**	**15**	**16**	**10**	**16**	**6**	**8**	**11**	**14**
CONTRACT OBLIGATIONS													
Canadian Entitlement	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Nichols Pumping net of PGE	**1**	1	1	1	1	1	1	1	1	1	1	1	1
TOTAL CONTRACT OBLIGATIONS	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
NET CONTRACT POSITION	**12**	**14**	**14**	**16**	**16**	**13**	**14**	**9**	**14**	**4**	**6**	**9**	**13**
HYDRO RESOURCES (Average Water)													
Spokane River	**123**	128	149	156	159	159	150	101	60	76	94	107	143
Clark Fork	**325**	247	261	227	357	603	644	394	297	147	150	262	313
Mid-Columbia	**10**	15	13	11	7	8	10	10	10	9	10	10	13
Sub-Total	**459**	390	423	394	523	770	805	505	367	232	254	378	469
THERMAL RESOURCES (Full Capability)													
Boulder Park	**25**	25	25	25	25	25	25	25	25	25	25	25	25
Colstrip	**222**	222	222	222	222	222	222	222	222	222	222	222	222
Coyote Springs 2	**132**	134	134	133	133	131	129	127	127	131	133	134	134
Coyote Springs 2 duct burner	**10**	10	10	10	10	10	10	10	10	10	10	10	10
Kettle Falls	**47**	47	47	47	47	47	47	47	47	47	47	47	47
Kettle Falls CT	**7**	7	7	7	7	7	7	7	7	7	7	7	7
Northeast	**53**	56	56	55	53	52	51	50	50	52	53	55	56
Rathdrum	**150**	157	156	153	150	147	145	142	143	146	150	154	156
Sub-Total	**645**	658	655	651	646	642	637	631	631	639	646	653	657
TOTAL RESOURCES	**1,104**	**1,047**	**1,078**	**1,045**	**1,170**	**1,412**	**1,441**	**1,135**	**998**	**871**	**900**	**1,031**	**1,125**
MAINTENANCE AND FORCED OUTAGE													
Boulder Park	**2**	1	1	4	4	1	1	1	1	1	1	1	1
Colstrip	**34**	31	31	31	31	74	31	31	31	31	31	31	31
Coyote Springs 2	**11**	7	7	7	7	63	6	6	6	7	7	7	7
Coyote Springs 2 duct burner	**1**	0	0	1	1	5	1	1	1	1	1	1	0
Kettle Falls	**5**	3	3	3	3	23	3	3	3	3	3	3	3
Kettle Falls CT	**1**	1	1	1	1	3	1	1	1	1	1	1	1
Northeast	**3**	3	3	3	3	3	3	3	3	3	3	3	3
Rathdrum	**20**	16	16	15	15	45	45	14	14	15	15	15	16
TOTAL MAINT AND FORCED OUTAGE	**76**	**61**	**61**	**64**	**63**	**216**	**90**	**59**	**59**	**60**	**60**	**61**	**61**
NET POSITION	**Annual**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Conditions	**(753)**	**(1,064)**	**(938)**	**(910)**	**(605)**	**(413)**	**(255)**	**(603)**	**(763)**	**(849)**	**(827)**	**(847)**	**(969)**
80% Confidence Interval	**(906)**	**(1,255)**	**(1,113)**	**(1,078)**	**(781)**	**(581)**	**(438)**	**(871)**	**(865)**	**(925)**	**(915)**	**(959)**	**(1,098)**

Table F.21
Monthly Loads & Resources Energy Forecast – 2023 (in aMW)

December 12, 2002 Version

Year 2023	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS													
Average Load	**1,796**	2,080	1,980	1,914	1,730	1,618	1,617	1,685	1,717	1,665	1,671	1,828	2,058
Potlatch Load	***64***	*64*	*64*	*64*	*64*	*64*	*64*	*64*	*64*	*64*	*64*	*64*	*64*
TOTAL LOADS	**1,860**	**2,144**	**2,044**	**1,978**	**1,794**	**1,682**	**1,681**	**1,749**	**1,781**	**1,729**	**1,735**	**1,892**	**2,122**
CONTRACT RIGHTS													
Black Creek Hydro	**1**	0	0	0	0	0	0	0	11	0	0	0	0
Small Power	**3**	3	3	4	5	4	4	4	2	2	2	3	3
Upriver	**9**	12	13	13	12	11	12	6	3	4	6	8	11
TOTAL CONTRACT RIGHTS	**13**	**15**	**16**	**17**	**17**	**15**	**16**	**10**	**16**	**6**	**8**	**11**	**14**
CONTRACT OBLIGATIONS													
Canadian Entitlement	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Nichols Pumping net of PGE	**1**	1	1	1	1	1	1	1	1	1	1	1	1
TOTAL CONTRACT OBLIGATIONS	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
NET CONTRACT POSITION	**12**	**14**	**14**	**16**	**16**	**14**	**14**	**9**	**15**	**4**	**6**	**9**	**13**
HYDRO RESOURCES (Average Water)													
Spokane River	**123**	128	149	156	159	159	150	101	60	76	94	107	143
Clark Fork	**325**	247	261	227	357	603	644	394	297	147	150	262	313
Mid-Columbia	**10**	14	12	10	7	8	9	9	9	9	9	9	12
Sub-Total	**458**	388	422	393	523	770	804	504	366	231	253	377	468
THERMAL RESOURCES (Full Capability)													
Boulder Park	**25**	25	25	25	25	25	25	25	25	25	25	25	25
Colstrip	**222**	222	222	222	222	222	222	222	222	222	222	222	222
Coyote Springs 2	**132**	134	134	133	133	131	129	127	127	131	133	134	134
Coyote Springs 2 duct burner	**10**	10	10	10	10	10	10	10	10	10	10	10	10
Kettle Falls	**47**	47	47	47	47	47	47	47	47	47	47	47	47
Kettle Falls CT	**7**	7	7	7	7	7	7	7	7	7	7	7	7
Northeast	**53**	56	56	55	53	52	51	50	50	52	53	55	56
Rathdrum	**150**	157	156	153	150	147	145	142	143	146	150	154	156
Sub-Total	**645**	658	655	651	646	642	637	631	631	639	646	653	657
TOTAL RESOURCES	**1,104**	**1,046**	**1,077**	**1,044**	**1,169**	**1,411**	**1,440**	**1,134**	**997**	**870**	**899**	**1,030**	**1,124**
MAINTENANCE AND FORCED OUTAGE													
Boulder Park	**2**	1	1	4	4	1	1	1	1	1	1	1	1
Colstrip	**34**	31	31	31	31	74	31	31	31	31	31	31	31
Coyote Springs 2	**14**	7	102	7	7	7	6	6	6	7	7	7	7
Coyote Springs 2 duct burner	**1**	0	8	1	1	1	1	1	1	1	1	1	0
Kettle Falls	**5**	3	3	3	3	23	3	3	3	3	3	3	3
Kettle Falls CT	**1**	1	1	1	1	3	1	1	1	1	1	1	1
Northeast	**3**	3	3	3	3	3	3	3	3	3	3	3	3
Rathdrum	**20**	16	16	15	15	45	45	14	14	15	15	15	16
TOTAL MAINT AND FORCED OUTAGE	**79**	**61**	**163**	**64**	**63**	**156**	**90**	**59**	**59**	**60**	**60**	**61**	**61**
NET POSITION	**Annual**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Conditions	**(824)**	**(1,145)**	**(1,116)**	**(982)**	**(671)**	**(413)**	**(316)**	**(665)**	**(828)**	**(914)**	**(890)**	**(913)**	**(1,046)**
80% Confidence Interval	**(977)**	**(1,336)**	**(1,290)**	**(1,150)**	**(847)**	**(581)**	**(499)**	**(933)**	**(929)**	**(991)**	**(978)**	**(1,025)**	**(1,175)**

Chart F.1
2004 Loads and Resources
Monthly Energy Position

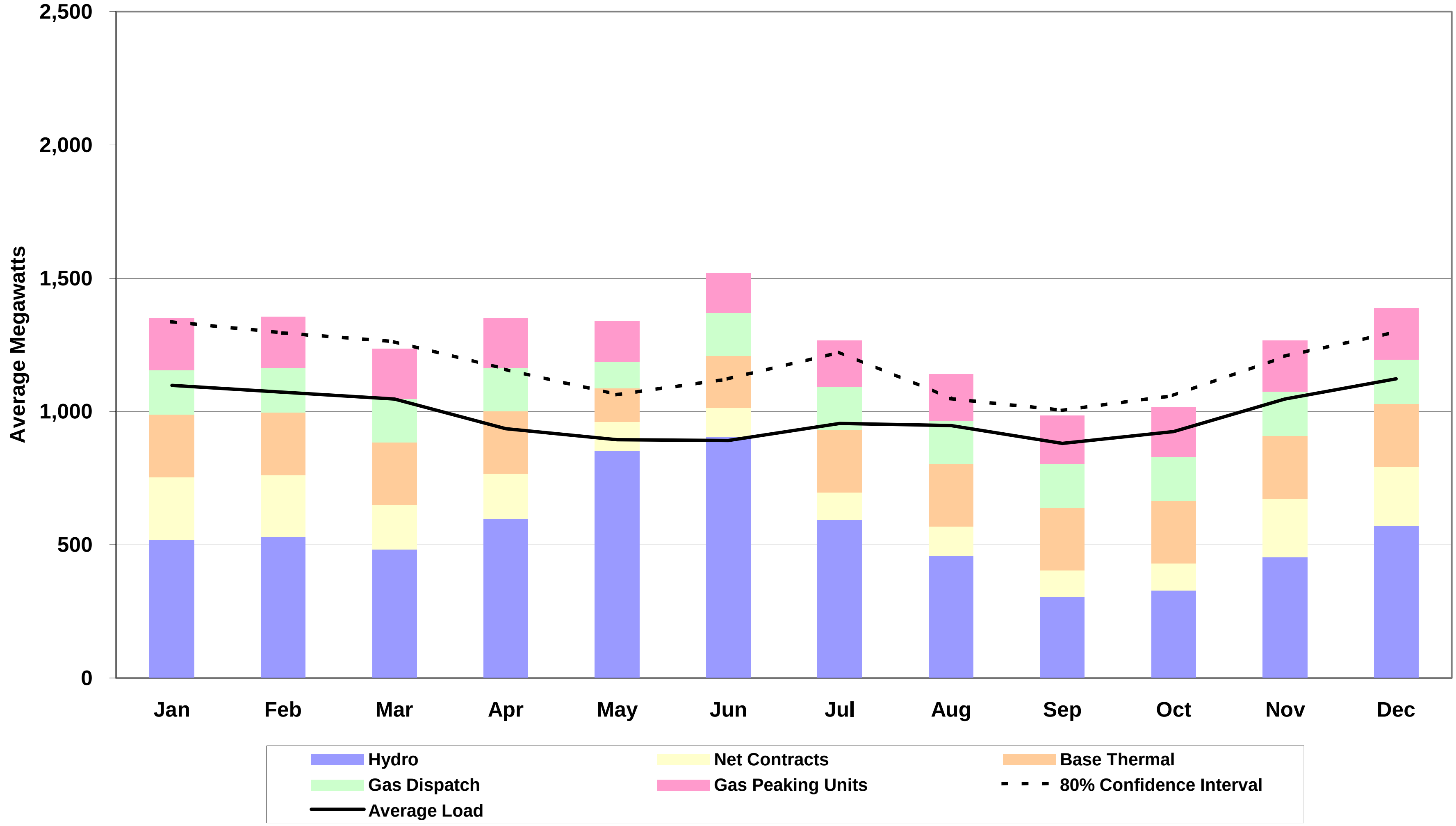


Chart F.2
2008 Loads and Resources
Monthly Energy Position

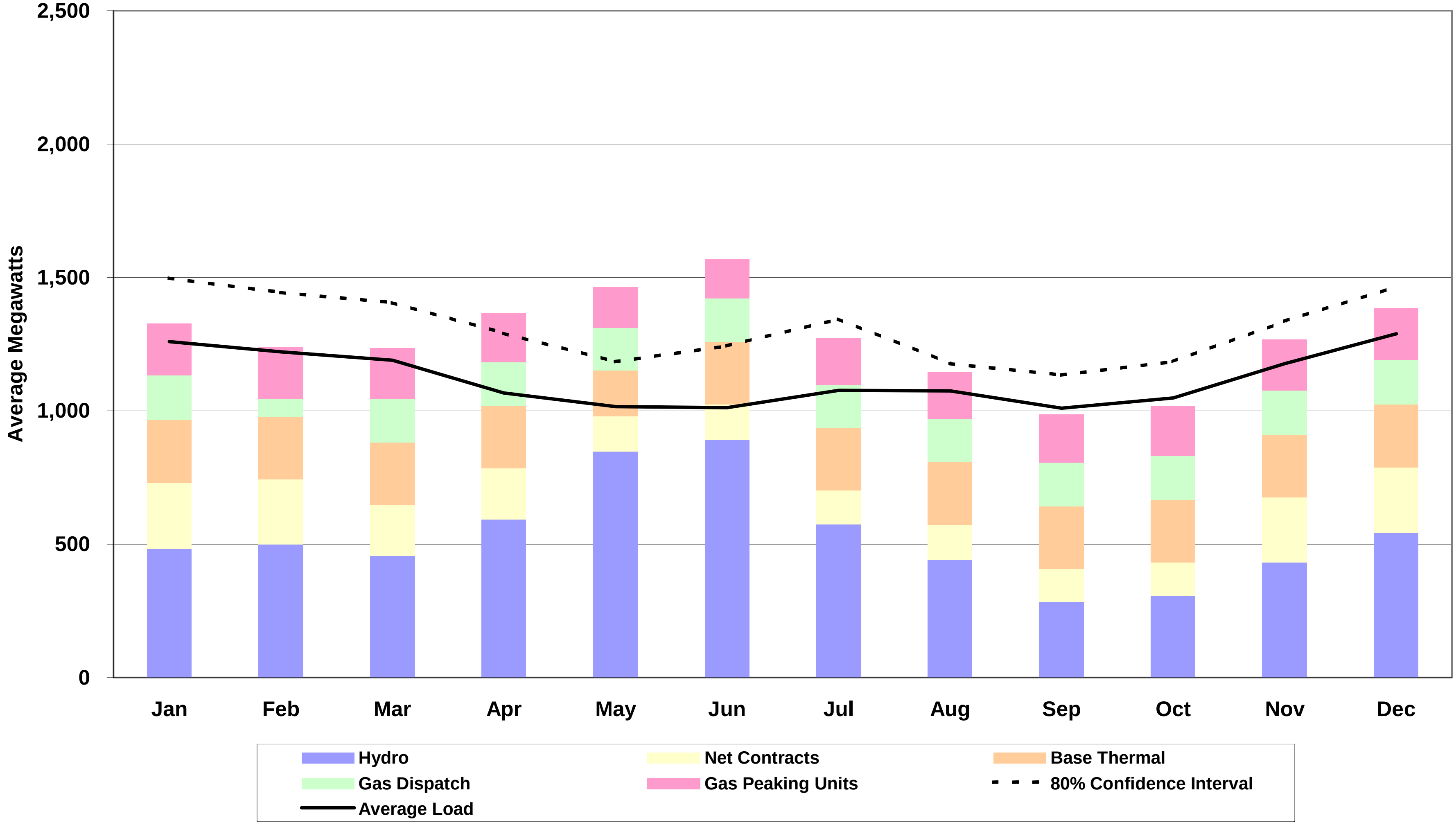


Chart F.3
2013 Loads and Resources
Monthly Energy Position

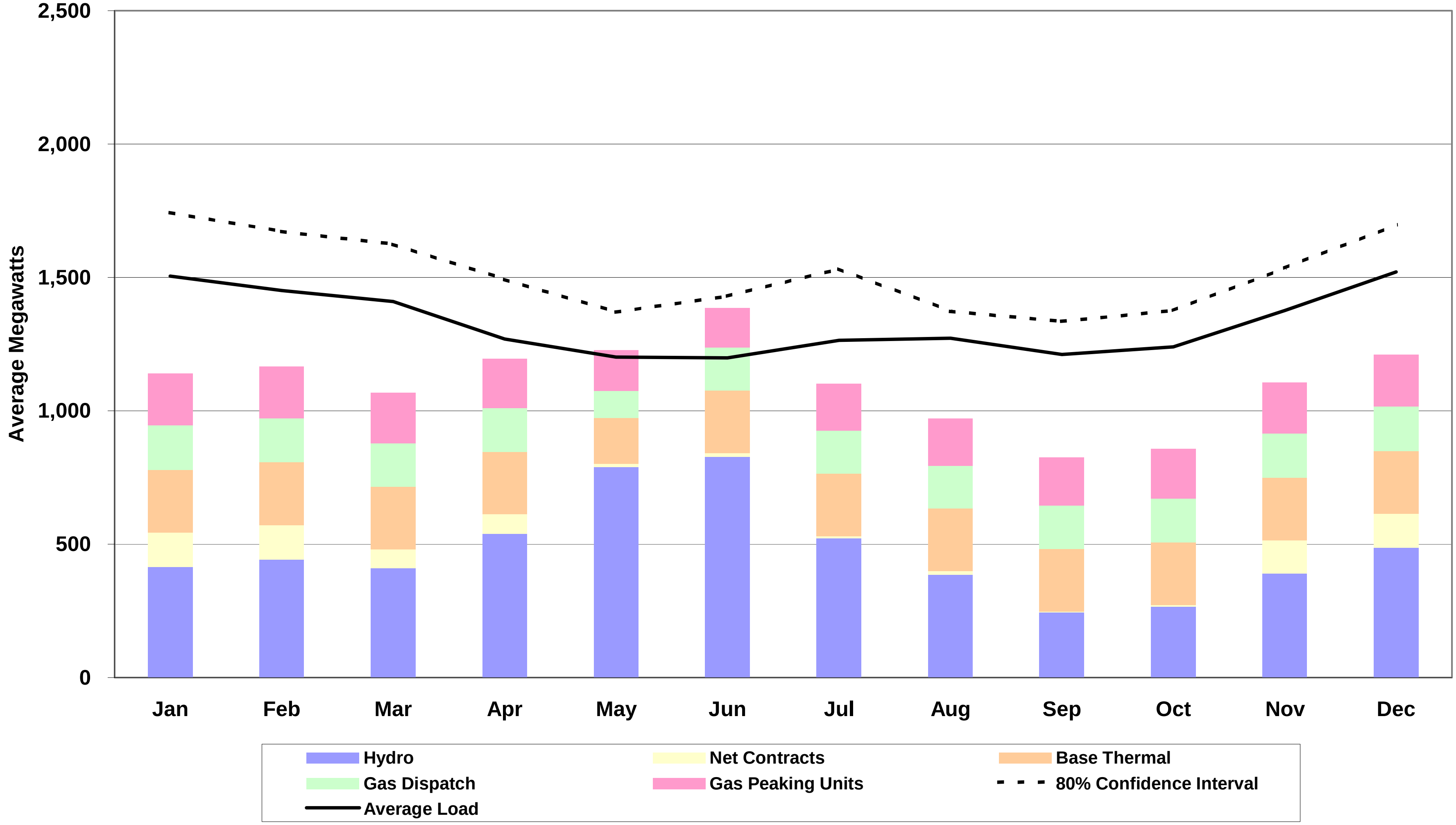


Chart F.4
2018 Loads and Resources
Monthly Energy Position

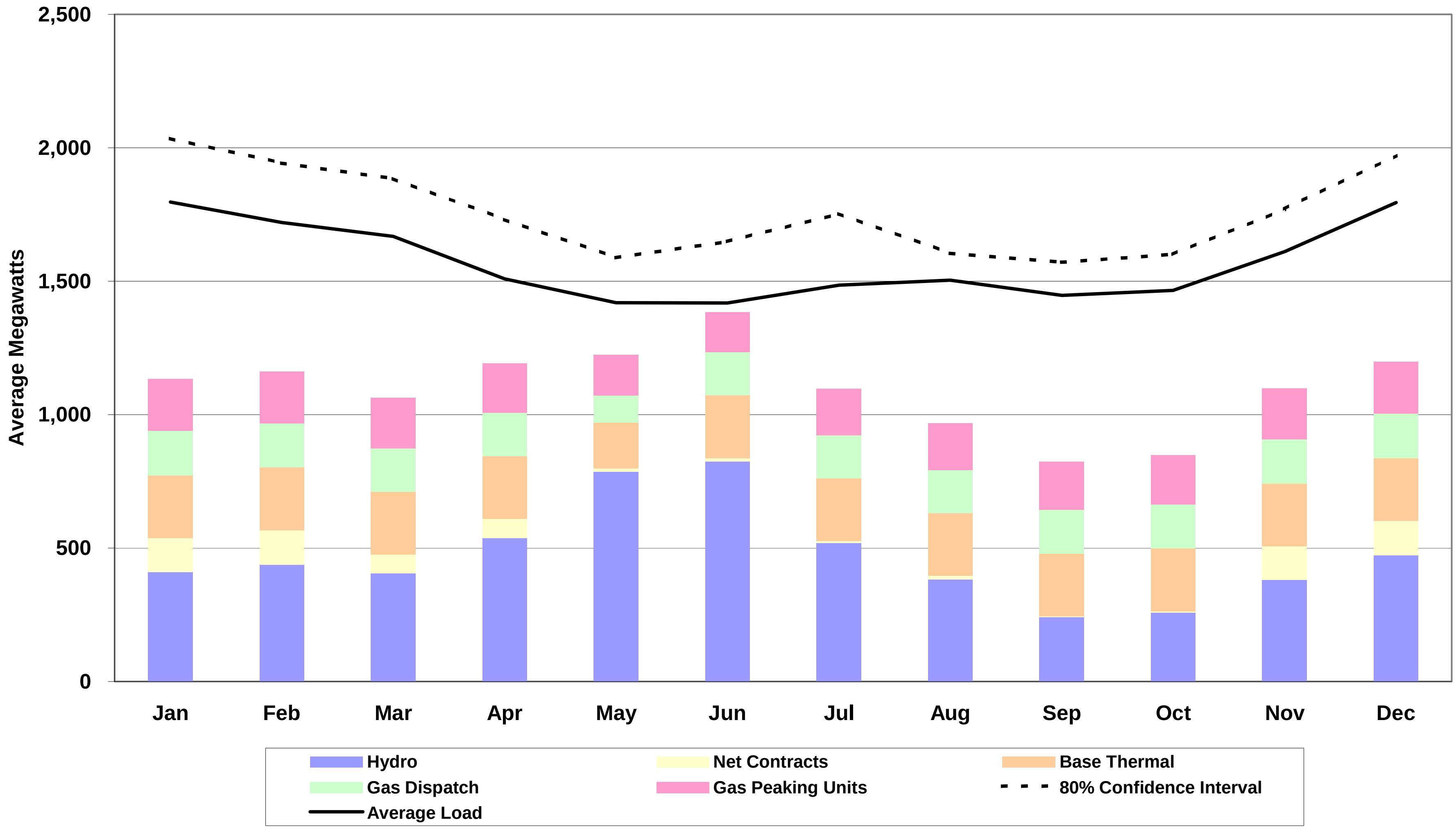


Chart F.5
2023 Loads and Resources
Monthly Energy Position

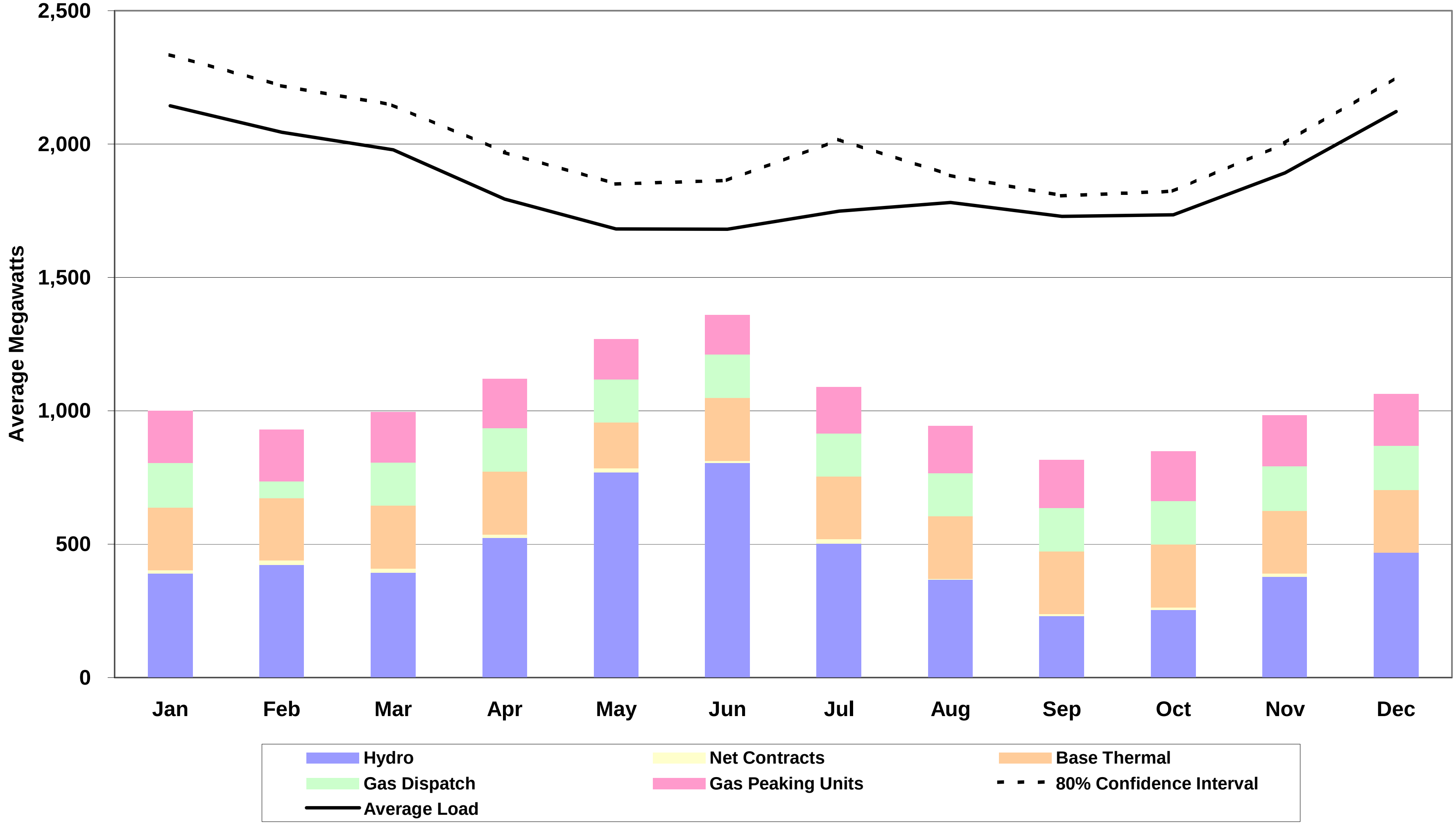


Table F.22
Annual Loads & Resources Capacity Forecast
2004-2023 (in MW)

Last Updated 12-12-2002	Notes	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
REQUIREMENTS																					
System Load	1	(1,470)	(1,515)	(1,570)	(1,617)	(1,672)	(1,740)	(1,803)	(1,864)	(1,920)	(1,982)	(2,039)	(2,115)	(2,191)	(2,270)	(2,349)	(2,425)	(2,501)	(2,592)	(2,687)	(2,780)
Contracts Out	2	(162)	(163)	(139)	(59)	(134)	(112)	(61)	(136)	(155)	(155)	(155)	(154)	(154)	(4)	(4)	(2)	(2)	(2)	(2)	(2)
Operating Reserves	3	(110)	(110)	(108)	(108)	(108)	(108)	(106)	(106)	(104)	(104)	(104)	(104)	(103)	(103)	(103)	(102)	(102)	(102)	(102)	(101)
Total Requirements		(1,742)	(1,788)	(1,817)	(1,784)	(1,914)	(1,960)	(1,970)	(2,106)	(2,179)	(2,241)	(2,298)	(2,373)	(2,448)	(2,377)	(2,456)	(2,529)	(2,605)	(2,696)	(2,791)	(2,883)
RESOURCES																					
Hydro	4	1,177	1,177	1,135	1,134	1,133	1,131	1,084	1,083	1,044	1,043	1,041	1,040	1,038	1,037	1,035	1,005	1,003	1,002	1,000	998
Contracts In	5	232	182	182	104	179	157	107	82	82	82	82	82	82	82	82	82	-	-	-	-
Base Load Thermals	6	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272	272
Gas Dispatch Units	7	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412
Total Resources		2,093	2,043	2,001	1,922	1,996	1,972	1,875	1,849	1,810	1,809	1,807	1,806	1,804	1,803	1,801	1,771	1,687	1,686	1,684	1,682
Surplus (Deficit)		**351**	**255**	**184**	**138**	**82**	**12**	**(95)**	**(257)**	**(369)**	**(432)**	**(491)**	**(567)**	**(644)**	**(574)**	**(655)**	**(758)**	**(918)**	**(1,010)**	**(1,107)**	**(1,201)**

Notes:
1. Load estimates are from the 2003 load forecast (08-27-2002) including the forecast for net Potlatch load.
2. Includes PacifiCorp Exchange Delivery, Nichols Pumping, and Canadian Entitlement Return contracts. Does not include WNP-3 Obligation.
3. 5% of hydro and 7% of thermal resources, per Northwest Power Pool reserve sharing agreement.
4. Total capacity for system hydro (Clark Fork and Spokane River projects) and contract hydro (mid-Columbia, Upriver and other small hydro) . Contract hydro numbers reflect the Priest Rapids and Wanapum contract extensions beginning in 2005.
5. Includes non-hydro small power contracts, Black Creek, market purchases of 100 MW flat for 2004-2010, PacifiCorp Exchange Return, and WNP-3 Receipt. BPA Residential Exchange is zero, assumes contract monetization.
6. Includes Colstrip and Kettle Falls.
7. Includes Coyote Springs, Boulder Park, and Kettle Falls CT.

Table F.23
Monthly Loads & Resources Capacity Forecast – 2004 (in MW)

Year 2004	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS												
Peak Load	1424	1390	1359	1218	1166	1229	1398	1329	1147	1204	1359	1455
Potlatch	46	46	46	46	46	46	46	46	46	46	46	46
CAPACITY CONTRACTS												
Black Creek Hydro	0	0	0	0	0	0	0	-10	0	0	0	0
Nichols Pumping	1	1	1	1	1	1	1	1	1	1	1	1
BPA Can. ENT> (Canada)	11	11	11	11	12	11	11	11	11	11	11	11
BPA-WNP3 Gross	-82	-82	-41	-41	0	0	0	0	0	0	-82	-82
Enron/PGE 20 Cap	150	150	150	150	150	150	150	150	150	150	150	150
PacifiCorp Exchange	-50	-50	0	0	0	0	0	0	0	0	0	0
Market Purchases	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100
BPA Residential Exchange	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL REQUIREMENTS	1400	1366	1426	1285	1275	1337	1506	1427	1255	1312	1385	1481
HYDRO RESOURCES												
System Hydro	973	972	960	959	952	971	979	978	970	969	974	976
Mid-Columbia	196	196	196	196	196	196	196	196	196	196	196	196
Small Hydro	4	4	4	4	4	4	4	4	4	4	4	4
Upriver Firm	4	4	9	16	16	12	9	3	5	7	7	6
Sub-Total	1177	1176	1169	1175	1168	1183	1188	1181	1175	1176	1181	1182
THERMAL RESOURCES												
Coyote Springs II	144	141	139	137	134	132	130	130	132	137	141	143
Colstrip	222	222	222	222	222	222	222	222	222	222	222	222
Northeast Turbine	60	59	57	56	55	55	50	50	55	56	57	60
Rathdrum CT	176	172	168	163	160	144	144	141	146	164	170	174
SIP	0	0	0	0	0	0	0	0	0	0	0	0
Boulder Park	25	25	25	25	25	25	25	25	25	25	25	25
Kettle Falls CT	7	7	7	7	7	7	7	7	7	7	7	7
Kettle Falls	50	50	50	50	50	50	50	50	50	50	50	50
Sub-Total	684	676	668	660	653	635	628	625	637	661	672	681
TOTAL RESOURCES	**1861**	**1852**	**1837**	**1835**	**1821**	**1818**	**1816**	**1806**	**1812**	**1837**	**1853**	**1863**
MAINTENANCE												
Coyote Springs II	0	0	0	0	-134	0	0	0	0	0	0	0
Spokane River	0	0	0	0	0	0	0	-24	-39	-31	-3	0
Clark Fork River	0	-116	-160	0	0	0	0	0	-58	-188	-188	-58
Mid-Columbia	0	0	0	-55	-55	-55	0	0	0	0	0	0
Rathdrum	0	0	-84	-82	-80	0	0	0	0	0	0	0
Kettle Falls	0	0	0	0	0	-50	0	0	0	0	0	0
Colstrip	0	0	0	0	-111	-111	0	0	0	0	0	0
Total Maintenance	0	-116	-244	-137	-380	-216	0	-24	-97	-219	-191	-58
Hydro Reserves 5% (Includes Box Canyon Gen)	62	62	62	62	62	63	63	61	60	61	62	63
Thermal Reserves 7% (Includes Vaagen Gen)	48	48	41	41	23	33	44	44	45	47	47	48
Total Reserves	110	110	103	103	85	96	107	105	105	107	110	110
	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04
CAPACITY SURPLUS (DEFICIT)	**351**	**260**	**64**	**310**	**81**	**169**	**203**	**250**	**355**	**199**	**167**	**214**

*Note: These figures assume maximum one hour peak loads for the month and one hour hydro capabilities. September 6, 2002 load forecast.
Revision No. 11 January 10, 2003 Doug Young

Table F.24
Monthly Loads & Resources Capacity Forecast – 2005 (in MW)

Year 2005	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS										2017		
Peak Load	1469	1432	1399	1255	1200	1263	1433	1365	1184	1239	1395	1503
Potlatch	46	46	46	46	46	46	46	46	46	46	46	46
CAPACITY CONTRACTS												
Black Creek Hydro	0	0	0	0	0	0	0	-10	0	0	0	0
Nichols Pumping	1	1	1	1	1	1	1	1	1	1	1	1
BPA Can. ENT> (Canada)	12	11	11	11	12	11	12	11	11	11	8	8
BPA-WNP3 Gross	-82	-82	-41	-41	0	0	0	0	0	0	-82	-82
Enron/PGE 20 Cap	150	150	150	150	150	150	150	150	150	150	150	150
Grant Displacement	0	0	0	0	0	0	0	0	0	0	-20	-20
Market Purchases	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100
BPA Residential Exchange	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL REQUIREMENTS	1496	1458	1466	1322	1309	1371	1542	1463	1292	1347	1398	1506
HYDRO RESOURCES												
System Hydro	973	972	960	959	952	971	979	978	970	969	974	976
Mid-Columbia	196	196	196	196	196	196	196	196	196	196	154	154
Small Hydro	4	4	4	4	4	4	4	4	4	4	4	4
Upriver Firm	4	4	9	16	16	12	9	3	5	7	7	6
Sub-Total	1177	1176	1169	1175	1168	1183	1188	1181	1175	1176	1139	1140
THERMAL RESOURCES												
Coyote Springs II	144	141	139	137	134	132	130	130	132	137	141	143
Colstrip	222	222	222	222	222	222	222	222	222	222	222	222
Northeast Turbine	60	59	57	56	55	55	50	50	55	56	57	60
Rathdrum CT	176	172	168	163	160	144	144	141	146	164	170	174
Boulder Park	25	25	25	25	25	25	25	25	25	25	25	25
Kettle Falls CT	7	7	7	7	7	7	7	7	7	7	7	7
Kettle Falls	50	50	50	50	50	50	50	50	50	50	50	50
Sub-Total	684	676	668	660	653	635	628	625	637	661	672	681
TOTAL RESOURCES	**1861**	**1852**	**1837**	**1835**	**1821**	**1818**	**1816**	**1806**	**1812**	**1837**	**1811**	**1821**
MAINTENANCE												
Coyote Springs II	0	0	0	0	-134	0	0	0	0	0	0	0
Spokane River	0	0	0	0	0	0	0	-15	-52	-31	-3	0
Clark Fork River	0	-116	-160	0	0	0	0	0	-102	-102	-102	-102
Mid-Columbia	0	0	0	-55	-55	-55	0	0	0	0	0	0
Rathdrum	0	0	-84	-82	-80	0	0	0	0	0	0	0
Kettle Falls	0	0	0	0	0	-50	0	0	0	0	0	0
Colstrip	0	0	0	0	0	0	0	0	0	0	0	0
Total Maintenance	0	-116	-244	-137	-269	-105	0	-15	-154	-133	-105	-102
Hydro Reserves 5% (Includes Box Canyon Gen)	62	56	54	59	59	60	63	62	54	56	55	55
Thermal Reserves 7% (Includes Vaagen Gen)	48	48	41	41	31	41	44	44	45	47	47	48
Total Reserves	110	104	95	100	90	101	107	106	99	102	102	103
	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
CAPACITY SURPLUS (DEFICIT)	**255**	**174**	**32**	**276**	**153**	**241**	**167**	**222**	**267**	**255**	**206**	**110**

*Note: These figures assume maximum one hour peak loads for the month and one hour hydro capabilities. September 6, 2002 load forecast.
Revision No. 11 January 10, 2003 Doug Young

Table F.25
Monthly Loads & Resources Capacity Forecast – 2006 (in MW)

Year 2006	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS										2017		
Peak Load	1524	1484	1448	1300	1241	1304	1474	1409	1229	1282	1440	1562
Potlatch	46	46	46	46	46	46	46	46	46	46	46	46
CAPACITY CONTRACTS												
Black Creek Hydro	0	0	0	0	0	0	0	-10	0	0	0	0
Nichols Pumping	1	1	1	1	1	1	1	1	1	1	1	1
BPA Can. ENT> (Canada)	8	8	8	8	8	8	8	8	8	8	8	8
BPA-WNP3 Gross	-82	-82	-41	-41	0	0	0	0	0	0	-82	-82
Enron/PGE 20 Cap	150	150	150	150	150	150	150	150	150	150	150	150
Grant Displacement	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20
Market Purchases	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100
BPA Residential Exchange	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL REQUIREMENTS	1527	1487	1492	1344	1326	1389	1559	1484	1314	1367	1443	1565
HYDRO RESOURCES												
System Hydro	973	972	960	959	952	971	979	978	970	969	974	976
Mid-Columbia	154	154	154	154	154	154	154	154	154	154	154	154
Small Hydro	4	4	4	4	4	4	4	4	4	4	4	4
Upriver Firm	4	4	9	16	16	12	9	3	5	7	7	6
Sub-Total	1135	1134	1127	1133	1126	1141	1146	1139	1133	1134	1139	1140
THERMAL RESOURCES												
Coyote Springs II	144	141	139	137	134	132	130	130	132	137	141	143
Colstrip	222	222	222	222	222	222	222	222	222	222	222	222
Northeast Turbine	60	59	57	56	55	55	50	50	55	56	57	60
Rathdrum CT	176	172	168	163	160	144	144	141	146	164	170	174
Boulder Park	25	25	25	25	25	25	25	25	25	25	25	25
Kettle Falls CT	7	7	7	7	7	7	7	7	7	7	7	7
Kettle Falls	50	50	50	50	50	50	50	50	50	50	50	50
Sub-Total	684	676	668	660	653	635	628	625	637	661	672	681
TOTAL RESOURCES	**1819**	**1810**	**1795**	**1793**	**1779**	**1776**	**1774**	**1764**	**1770**	**1795**	**1811**	**1821**
MAINTENANCE												
Coyote Springs II	0	0	0	0	-134	0	0	0	0	0	0	0
Spokane River	0	0	0	0	0	0	0	-15	-52	-53	-3	0
Clark Fork River	0	-166	-166	-102	0	0	0	0	-102	-102	-102	-102
Mid-Columbia	0	0	0	-43	-43	-43	0	0	0	0	0	0
Rathdrum	0	0	0	0	-80	0	0	0	0	0	0	0
Kettle Falls	0	0	0	0	0	-50	0	0	0	0	0	0
Colstrip	0	0	0	0	-111	-111	0	0	0	0	0	0
Total Maintenance	0	-166	-166	-145	-368	-204	0	-15	-154	-155	-105	-102
Hydro Reserves 5% (Includes Box Canyon Gen)	60	52	51	53	58	58	61	60	52	52	55	55
Thermal Reserves 7% (Includes Vaagen Gen)	48	48	47	46	23	33	44	44	45	47	47	48
Total Reserves	108	99	98	99	81	92	105	104	97	99	102	103
	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06
CAPACITY SURPLUS (DEFICIT)	**184**	**58**	**39**	**205**	**4**	**91**	**110**	**161**	**205**	**174**	**161**	**51**

*Note: These figures assume maximum one hour peak loads for the month and one hour hydro capabilities. September 6, 2002 load forecast.
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Table F.26
Monthly Loads & Resources Capacity Forecast – 2007 (in MW)

Year 2007	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS										2017		
Peak Load	1569	1525	1488	1336	1274	1338	1508	1444	1265	1316	1476	1610
Potlatch	48	48	48	48	48	48	48	48	48	48	48	48
CAPACITY CONTRACTS												
Black Creek Hydro	0	0	0	0	0	0	0	-10	0	0	0	0
Nichols Pumping	1	1	1	1	1	1	1	1	1	1	1	1
BPA Can. ENT> (Canada)	8	8	8	8	8	8	8	8	8	8	8	8
BPA-WNP3 Gross	-82	-82	-41	-41	0	0	0	0	0	0	-82	-82
Enron/PGE 20 Cap	150	150	150	150	150	150	150	150	150	150	150	150
Grant Displacement	0	0	0	0	0	0	0	0	0	0	0	0
Market Purchases	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100
BPA Residential Exchange	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL REQUIREMENTS	1594	1550	1554	1402	1381	1445	1615	1541	1372	1423	1501	1635
HYDRO RESOURCES												
System Hydro	973	972	960	959	952	971	979	978	970	969	974	976
Mid-Columbia	153	153	153	153	153	153	153	153	153	153	153	153
Small Hydro	4	4	4	4	4	4	4	4	4	4	4	4
Upriver Firm	4	4	9	16	16	12	9	3	5	7	7	6
Sub-Total	1134	1133	1126	1132	1125	1140	1145	1138	1132	1133	1138	1139
THERMAL RESOURCES												
Coyote Springs II	144	141	139	137	134	132	130	130	132	137	141	143
Colstrip	222	222	222	222	222	222	222	222	222	222	222	222
Northeast Turbine	60	59	57	56	55	55	50	50	55	56	57	60
Rathdrum CT	176	172	168	163	160	144	144	141	146	164	170	174
Boulder Park	25	25	25	25	25	25	25	25	25	25	25	25
Kettle Falls CT	7	7	7	7	7	7	7	7	7	7	7	7
Kettle Falls	50	50	50	50	50	50	50	50	50	50	50	50
Sub-Total	684	676	668	660	653	635	628	625	637	661	672	681
TOTAL RESOURCES	**1818**	**1809**	**1794**	**1792**	**1778**	**1775**	**1773**	**1763**	**1769**	**1794**	**1810**	**1820**
MAINTENANCE												
Coyote Springs II	0	0	0	0	-134	0	0	0	0	0	0	0
Spokane River	0	0	0	0	0	0	0	-15	-52	-53	-3	0
Clark Fork River	0	-166	-166	-102	0	0	0	0	-102	-102	-102	-102
Mid-Columbia	0	0	0	-43	-43	-43	0	0	0	0	0	0
Rathdrum	0	0	0	0	-80	0	0	0	0	0	0	0
Kettle Falls	0	0	0	0	0	-50	0	0	0	0	0	0
Colstrip	0	0	0	0	-111	-111	0	0	0	0	0	0
Total Maintenance	0	-166	-166	-145	-368	-204	0	-15	-154	-155	-105	-102
Hydro Reserves 5% (Includes Box Canyon Gen)	60	52	51	53	58	58	61	60	52	52	55	55
Thermal Reserves 7% (Includes Vaagen Gen)	48	48	47	46	23	33	44	44	45	47	47	48
Total Reserves	108	99	98	99	81	92	105	104	97	99	102	103
	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07
CAPACITY SURPLUS (DEFICIT)	**116**	**-6**	**-24**	**146**	**-52**	**34**	**53**	**103**	**146**	**117**	**102**	**-20**

*Note: These figures assume maximum one hour peak loads for the month and one hour hydro capabilities. September 6, 2002 load forecast.
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Table F.27
Monthly Loads & Resources Capacity Forecast – 2008 (in MW)

Year 2008	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS										2017		
Peak Load	1624	1577	1537	1382	1316	1379	1550	1488	1309	1359	1520	1662
Potlatch	48	48	48	48	48	48	48	48	48	48	48	48
CAPACITY CONTRACTS												
Black Creek Hydro	0	0	0	0	0	0	0	-10	0	0	0	0
Nichols Pumping	1	1	1	1	1	1	1	1	1	1	1	1
BPA Can. ENT> (Canada)	8	8	8	8	8	8	8	8	8	8	8	8
BPA-WNP3 Gross	-82	-82	-41	-41	0	0	0	0	0	0	-82	-82
Enron/PGE 20 Cap	150	150	150	150	150	150	150	150	150	150	150	150
Grant Displacement	0	0	0	0	0	0	0	0	0	0	0	0
Market Purchases	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100
BPA Residential Exchange	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL REQUIREMENTS	1649	1602	1603	1448	1423	1486	1657	1585	1416	1466	1545	1687
HYDRO RESOURCES												
System Hydro	973	972	960	959	952	971	979	978	970	969	974	976
Mid-Columbia	152	152	152	152	152	152	152	152	152	152	152	152
Small Hydro	4	4	4	4	4	4	4	4	4	4	4	4
Upriver Firm	4	4	9	16	16	12	9	3	5	7	7	6
Sub-Total	1133	1132	1125	1131	1124	1139	1144	1137	1131	1132	1137	1138
THERMAL RESOURCES												
Coyote Springs II	144	141	139	137	134	132	130	130	132	137	141	143
Colstrip	222	222	222	222	222	222	222	222	222	222	222	222
Northeast Turbine	60	59	57	56	55	55	50	50	55	56	57	60
Rathdrum CT	176	172	168	163	160	144	144	141	146	164	170	174
Boulder Park	25	25	25	25	25	25	25	25	25	25	25	25
Kettle Falls CT	7	7	7	7	7	7	7	7	7	7	7	7
Kettle Falls	50	50	50	50	50	50	50	50	50	50	50	50
Sub-Total	684	676	668	660	653	635	628	625	637	661	672	681
TOTAL RESOURCES	**1817**	**1808**	**1793**	**1791**	**1777**	**1774**	**1772**	**1762**	**1768**	**1793**	**1809**	**1819**
MAINTENANCE												
Coyote Springs II	0	0	0	0	-134	0	0	0	0	0	0	0
Spokane River	0	0	0	0	0	0	0	-15	-52	-53	-3	0
Clark Fork River	0	-166	-166	-102	0	0	0	0	-102	-102	-102	-102
Mid-Columbia	0	0	0	-43	-43	-43	0	0	0	0	0	0
Rathdrum	0	0	0	0	-80	0	0	0	0	0	0	0
Kettle Falls	0	0	0	0	0	-50	0	0	0	0	0	0
Colstrip	0	0	0	0	0	0	0	0	0	0	0	0
Total Maintenance	0	-166	-166	-145	-257	-93	0	-15	-154	-155	-105	-102
Hydro Reserves 5% (Includes Box Canyon Gen)	60	52	51	53	57	58	61	60	52	52	55	55
Thermal Reserves 7% (Includes Vaagen Gen)	48	48	47	46	31	41	44	44	45	47	47	48
Total Reserves	108	99	98	99	88	99	105	104	97	99	102	103
	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08
CAPACITY SURPLUS (DEFICIT)	**60**	**-59**	**-74**	**99**	**9**	**96**	**10**	**58**	**101**	**73**	**57**	**-73**

*Note: These figures assume maximum one hour peak loads for the month and one hour hydro capabilities. September 6, 2002 load forecast.
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Table F.28
Monthly Loads & Resources Capacity Forecast – 2009 (in MW)

Year 2009	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS										2017		
Peak Load	1690	1638	1596	1436	1365	1429	1600	1541	1363	1410	1573	1724
Potlatch	50	50	50	50	50	50	50	50	50	50	50	50
CAPACITY CONTRACTS												
Black Creek Hydro	0	0	0	0	0	0	0	-10	0	0	0	0
Nichols Pumping	1	1	1	1	1	1	1	1	1	1	1	1
BPA Can. ENT> (Canada)	8	8	8	8	8	8	8	8	8	8	6	6
BPA-WNP3 Gross	-82	-82	-41	-41	0	0	0	0	0	0	-82	-82
Grant Displacement	-22	-22	-22	-22	-22	-22	-22	-22	-22	-22	-22	-22
Enron/PGE 20 Cap	150	150	150	150	150	150	150	150	150	150	150	150
Market Purchases	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100
BPA Residential Exchange	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL REQUIREMENTS	1695	1643	1642	1482	1452	1516	1687	1618	1450	1497	1576	1727
HYDRO RESOURCES												
System Hydro	973	972	960	959	952	971	979	978	970	969	974	976
Mid-Columbia	150	150	150	150	150	150	150	150	150	150	103	103
Small Hydro	4	4	4	4	4	4	4	4	4	4	4	4
Upriver Firm	4	4	9	16	16	12	9	3	5	7	7	6
Sub-Total	1131	1130	1123	1129	1122	1137	1142	1135	1129	1130	1088	1089
THERMAL RESOURCES												
Coyote Springs II	144	141	139	137	134	132	130	130	132	137	141	143
Colstrip	222	222	222	222	222	222	222	222	222	222	222	222
Northeast Turbine	60	59	57	56	55	55	50	50	55	56	57	60
Rathdrum CT	176	172	168	163	160	144	144	141	146	164	170	174
Boulder Park	25	25	25	25	25	25	25	25	25	25	25	25
Kettle Falls CT	7	7	7	7	7	7	7	7	7	7	7	7
Kettle Falls	50	50	50	50	50	50	50	50	50	50	50	50
Sub-Total	684	676	668	660	653	635	628	625	637	661	672	681
TOTAL RESOURCES	**1815**	**1806**	**1791**	**1789**	**1775**	**1772**	**1770**	**1760**	**1766**	**1791**	**1760**	**1770**
MAINTENANCE												
Coyote Springs II	0	0	0	0	-134	0	0	0	0	0	0	0
Spokane River	0	0	0	0	0	0	0	-15	-52	-53	-3	0
Clark Fork River	0	-166	-166	-102	0	0	0	0	-102	-102	-102	-102
Mid-Columbia	0	0	0	-42	-42	-42	0	0	0	0	0	0
Rathdrum	0	0	0	0	-80	0	0	0	0	0	0	0
Kettle Falls	0	0	0	0	0	-50	0	0	0	0	0	0
Colstrip	0	0	0	0	-111	0	0	0	0	0	0	0
Total Maintenance	0	-166	-166	-144	-367	-92	0	-15	-154	-155	-105	-102
Hydro Reserves 5% (Includes Box Canyon Gen)	60	52	51	53	57	58	61	59	52	52	53	53
Thermal Reserves 7% (Includes Vaagen Gen)	48	48	47	46	23	41	44	44	45	47	47	48
Total Reserves	108	99	98	99	81	99	105	103	97	99	100	101
	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
CAPACITY SURPLUS (DEFICIT)	**12**	**-102**	**-115**	**64**	**-125**	**65**	**-22**	**24**	**65**	**40**	**-21**	**-160**

*Note: These figures assume maximum one hour peak loads for the month and one hour hydro capabilities. September 6, 2002 load forecast.
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Table F.29
Monthly Loads & Resources Capacity Forecast – 2010 (in MW)

Year 2010	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS										2017		
Peak Load	1753	1696	1651	1487	1412	1476	1647	1591	1414	1458	1624	1783
Potlatch	50	50	50	50	50	50	50	50	50	50	50	50
CAPACITY CONTRACTS												
Black Creek Hydro	0	0	0	0	0	0	0	-10	0	0	0	0
Nichols Pumping	1	1	1	1	1	1	1	1	1	1	1	1
BPA Can. ENT> (Canada)	6	6	6	6	6	6	6	6	6	6	6	6
BPA-WNP3 Gross	-82	-82	-41	-41	0	0	0	0	0	0	-82	-82
Enron/PGE 20 Cap	150	150	150	150	150	150	150	150	150	150	150	150
Grant Displacement	-21	-21	-21	-21	-21	-21	-21	-21	-21	-21	-21	-21
Market Purchases	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100
BPA Residential Exchange	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL REQUIREMENTS	1757	1700	1696	1532	1498	1562	1733	1667	1500	1544	1628	1787
HYDRO RESOURCES												
System Hydro	973	972	960	959	952	971	979	978	970	969	974	976
Mid-Columbia	103	103	103	103	103	103	103	103	103	103	103	103
Small Hydro	4	4	4	4	4	4	4	4	4	4	4	4
Upriver Firm	4	4	9	16	16	12	9	3	5	7	7	6
Sub-Total	1084	1083	1076	1082	1075	1090	1095	1088	1082	1083	1088	1089
THERMAL RESOURCES												
Coyote Springs II	144	141	139	137	134	132	130	130	132	137	141	143
Colstrip	222	222	222	222	222	222	222	222	222	222	222	222
Northeast Turbine	60	59	57	56	55	55	50	50	55	56	57	60
Rathdrum CT	176	172	168	163	160	144	144	141	146	164	170	174
Boulder Park	25	25	25	25	25	25	25	25	25	25	25	25
Kettle Falls CT	7	7	7	7	7	7	7	7	7	7	7	7
Kettle Falls	50	50	50	50	50	50	50	50	50	50	50	50
Sub-Total	684	676	668	660	653	635	628	625	637	661	672	681
TOTAL RESOURCES	**1768**	**1759**	**1744**	**1742**	**1728**	**1725**	**1723**	**1713**	**1719**	**1744**	**1760**	**1770**
MAINTENANCE												
Coyote Springs II	0	0	0	0	-134	0	0	0	0	0	0	0
Spokane River	0	0	0	0	0	0	0	-15	-52	-53	-3	0
Clark Fork River		-166	-166	-102	0	0	0	0	-102	-102	-102	-102
Mid-Columbia	0	0	0	-29	-29	-29	0	0	0	0	0	0
Rathdrum	0	0	0	0	-80	0	0	0	0	0	0	0
Kettle Falls	0	0	0	0	0	-50	0	0	0	0	0	0
Colstrip	0	0	0	0	-111	0	0	0	0	0	0	0
Total Maintenance	0	-166	-166	-131	-354	-79	0	-15	-154	-155	-105	-102
Hydro Reserves 5% (Includes Box Canyon Gen)	58	49	49	51	56	56	58	57	50	50	53	53
Thermal Reserves 7% (Includes Vaagen Gen)	48	48	47	46	23	41	44	44	45	47	47	48
Total Reserves	106	97	96	97	79	98	102	101	95	96	100	101
	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
CAPACITY SURPLUS (DEFICIT)	**-95**	**-204**	**-214**	**-18**	**-203**	**-14**	**-112**	**-70**	**-30**	**-51**	**-73**	**-220**

Table F.30
Monthly Loads & Resources Capacity Forecast – 2011 (in MW)

Year 2011	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS										2017		
Peak Load	1812	1751	1704	1535	1457	1520	1692	1638	1462	1504	1672	1839
Potlatch	52	52	52	52	52	52	52	52	52	52	52	52
CAPACITY CONTRACTS												
Black Creek Hydro	0	0	0	0	0	0	0	-10	0	0	0	0
Nichols Pumping	1	1	1	1	1	1	1	1	1	1	1	1
BPA Can. ENT> (Canada)	6	6	6	6	6	6	6	6	6	6	4	4
BPA-WNP3 Gross	-82	-82	-41	-41	0	0	0	0	0	0	-82	-82
Enron/PGE 20 Cap	150	150	150	150	150	150	150	150	150	150	150	150
Grant Displacement	-21	-21	-21	-21	-21	-21	-21	-21	-21	-21	-21	-21
Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0
BPA Residential Exchange	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL REQUIREMENTS	1918	1857	1851	1682	1645	1708	1880	1816	1650	1692	1776	1943
HYDRO RESOURCES												
System Hydro	973	972	960	959	952	971	979	978	970	969	974	976
Mid-Columbia	102	102	102	102	102	102	102	102	102	102	63	63
Small Hydro	4	4	4	4	4	4	4	4	4	4	4	4
Upriver Firm	4	4	9	16	16	12	9	3	5	7	7	6
Sub-Total	1083	1082	1075	1081	1074	1089	1094	1087	1081	1082	1048	1049
THERMAL RESOURCES												
Coyote Springs II	144	141	139	137	134	132	130	130	132	137	141	143
Colstrip	222	222	222	222	222	222	222	222	222	222	222	222
Northeast Turbine	60	59	57	56	55	55	50	50	55	56	57	60
Rathdrum CT	176	172	168	163	160	144	144	141	146	164	170	174
Boulder Park	25	25	25	25	25	25	25	25	25	25	25	25
Kettle Falls CT	7	7	7	7	7	7	7	7	7	7	7	7
Kettle Falls	50	50	50	50	50	50	50	50	50	50	50	50
Sub-Total	684	676	668	660	653	635	628	625	637	661	672	681
TOTAL RESOURCES	**1767**	**1758**	**1743**	**1741**	**1727**	**1724**	**1722**	**1712**	**1718**	**1743**	**1720**	**1730**
MAINTENANCE												
Coyote Springs II	0	0	0	0	-134	0	0	0	0	0	0	0
Spokane River	0	0	0	0	0	0	0	-15	-52	-53	-3	0
Clark Fork River	0	-166	-166	-102	0	0	0	0	-102	-102	-102	-102
Mid-Columbia	0	0	0	-29	-29	-29	0	0	0	0	0	0
Rathdrum	0	0	0	0	-80	0	0	0	0	0	0	0
Kettle Falls	0	0	0	0	0	-50	0	0	0	0	0	0
Colstrip	0	0	0	0	-111	0	0	0	0	0	0	0
Total Maintenance	0	-166	-166	-131	-354	-79	0	-15	-154	-155	-105	-102
Hydro Reserves 5% (Includes Box Canyon Gen)	58	49	49	51	56	56	58	57	50	50	51	51
Thermal Reserves 7% (Includes Vaagen Gen)	48	48	47	46	23	41	44	44	45	47	47	48
Total Reserves	106	97	96	97	79	98	102	101	95	96	98	99
	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
CAPACITY SURPLUS (DEFICIT)	**-257**	**-362**	**-370**	**-169**	**-351**	**-161**	**-260**	**-220**	**-181**	**-200**	**-259**	**-414**

*Note: These figures assume maximum one hour peak loads for the month and one hour hydro capabilities. September 6, 2002 load forecast.
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Table F.31
Monthly Loads & Resources Capacity Forecast – 2012 (in MW)

Year 2012	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS										2017		
Peak Load	1868	1803	1753	1581	1498	1562	1734	1682	1507	1547	1716	1891
Potlatch	52	52	52	52	52	52	52	52	52	52	52	52
CAPACITY CONTRACTS												
Black Creek Hydro	0	0	0	0	0	0	0	-10	0	0	0	0
Nichols Pumping	1	1	1	1	1	1	1	1	1	1	1	1
BPA Can. ENT> (Canada)	4	4	4	4	4	4	4	4	4	4	4	4
BPA-WNP3 Gross	-82	-82	-41	-41	0	0	0	0	0	0	-82	-82
Enron/PGE 20 Cap	150	150	150	150	150	150	150	150	150	150	150	150
Grant Displacement	0	0	0	0	0	0	0	0	0	0	0	0
Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0
BPA Residential Exchange	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL REQUIREMENTS	1993	1928	1919	1747	1705	1769	1941	1879	1714	1754	1841	2016
HYDRO RESOURCES												
System Hydro	973	972	960	959	952	971	979	978	970	969	974	976
Mid-Columbia	63	63	63	63	63	63	63	63	63	63	63	63
Small Hydro	4	4	4	4	4	4	4	4	4	4	4	4
Upriver Firm	4	4	9	16	16	12	9	3	5	7	7	6
Sub-Total	1044	1043	1036	1042	1035	1050	1055	1048	1042	1043	1048	1049
THERMAL RESOURCES												
Coyote Springs II	144	141	139	137	134	132	130	130	132	137	141	143
Colstrip	222	222	222	222	222	222	222	222	222	222	222	222
Northeast Turbine	60	59	57	56	55	55	50	50	55	56	57	60
Rathdrum CT	176	172	168	163	160	144	144	141	146	164	170	174
Boulder Park	25	25	25	25	25	25	25	25	25	25	25	25
Kettle Falls CT	7	7	7	7	7	7	7	7	7	7	7	7
Kettle Falls	50	50	50	50	50	50	50	50	50	50	50	50
Sub-Total	684	676	668	660	653	635	628	625	637	661	672	681
TOTAL RESOURCES	**1728**	**1719**	**1704**	**1702**	**1688**	**1685**	**1683**	**1673**	**1679**	**1704**	**1720**	**1730**
MAINTENANCE												
Coyote Springs II	0	0	0	0	-134	0	0	0	0	0	0	0
Spokane River	0	0	0	0	0	0	0	-15	-52	-53	-3	0
Clark Fork River	0	-166	-166	-102	0	0	0	0	-102	-102	-102	-102
Mid-Columbia	0	0	0	-18	-18	-18	0	0	0	0	0	0
Rathdrum	0	0	0	0	-80	0	0	0	0	0	0	0
Kettle Falls	0	0	0	0	0	-50	0	0	0	0	0	0
Colstrip	0	0	0	0	-111	0	0	0	0	0	0	0
Total Maintenance	0	-166	-166	-120	-343	-68	0	-15	-154	-155	-105	-102
Hydro Reserves 5% (Includes Box Canyon Gen)	56	47	47	50	54	55	56	55	48	48	51	51
Thermal Reserves 7% (Includes Vaagen Gen)	48	48	47	46	23	41	44	44	45	47	47	48
Total Reserves	104	95	94	96	77	96	100	99	93	94	98	99
	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
CAPACITY SURPLUS (DEFICIT)	**-369**	**-470**	**-475**	**-261**	**-437**	**-248**	**-358**	**-320**	**-282**	**-299**	**-324**	**-487**

*Note: These figures assume maximum one hour peak loads for the month and one hour hydro capabilities. September 6, 2002 load forecast.
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Table F.32
Monthly Loads & Resources Capacity Forecast – 2013 (in MW)

Year 2013	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS										2017		
Peak Load	1928	1859	1807	1630	1543	1607	1780	1730	1555	1593	1765	1948
Potlatch	54	54	54	54	54	54	54	54	54	54	54	54
CAPACITY CONTRACTS												
Black Creek Hydro	0	0	0	0	0	0	0	-10	0	0	0	0
Nichols Pumping	1	1	1	1	1	1	1	1	1	1	1	1
BPA Can. ENT> (Canada)	4	4	4	4	4	4	4	4	4	4	4	4
BPA-WNP3 Gross	-82	-82	-41	-41	0	0	0	0	0	0	-82	-82
Enron/PGE 20 Cap	150	150	150	150	150	150	150	150	150	150	150	150
Grant Displacement	0	0	0	0	0	0	0	0	0	0	0	0
Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0
BPA Residential Exchange	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL REQUIREMENTS	2055	1986	1975	1798	1752	1816	1989	1929	1764	1802	1892	2075
HYDRO RESOURCES												
System Hydro	973	972	960	959	952	971	979	978	970	969	974	976
Mid-Columbia	62	62	62	62	62	62	62	62	62	62	62	62
Small Hydro	4	4	4	4	4	4	4	4	4	4	4	4
Upriver Firm	4	4	9	16	16	12	9	3	5	7	7	6
Sub-Total	1043	1042	1035	1041	1034	1049	1054	1047	1041	1042	1047	1048
THERMAL RESOURCES												
Coyote Springs II	144	141	139	137	134	132	130	130	132	137	141	143
Colstrip	222	222	222	222	222	222	222	222	222	222	222	222
Northeast Turbine	60	59	57	56	55	55	50	50	55	56	57	60
Rathdrum CT	176	172	168	163	160	144	144	141	146	164	170	174
Boulder Park	25	25	25	25	25	25	25	25	25	25	25	25
Kettle Falls CT	7	7	7	7	7	7	7	7	7	7	7	7
Kettle Falls	50	50	50	50	50	50	50	50	50	50	50	50
Sub-Total	684	676	668	660	653	635	628	625	637	661	672	681
TOTAL RESOURCES	**1727**	**1718**	**1703**	**1701**	**1687**	**1684**	**1682**	**1672**	**1678**	**1703**	**1719**	**1729**
MAINTENANCE												
Coyote Springs II	0	0	0	0	-134	0	0	0	0	0	0	0
Spokane River	0	0	0	0	0	0	0	-15	-52	-53	-3	0
Clark Fork River	0	-166	-166	-102	0	0	0	0	-102	-102	-102	-102
Mid-Columbia	0	0	0	-17	-17	-17	0	0	0	0	0	0
Rathdrum	0	0	0	0	-80	0	0	0	0	0	0	0
Kettle Falls	0	0	0	0	0	-50	0	0	0	0	0	0
Colstrip	0	0	0	0	-111	0	0	0	0	0	0	0
Total Maintenance	0	-166	-166	-119	-342	-67	0	-15	-154	-155	-105	-102
Hydro Reserves 5% (Includes Box Canyon Gen)	56	47	47	50	54	55	56	55	48	48	51	51
Thermal Reserves 7% (Includes Vaagen Gen)	48	48	47	46	23	41	44	44	45	47	47	48
Total Reserves	104	95	94	96	77	96	100	99	93	94	98	99
	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
CAPACITY SURPLUS (DEFICIT)	**-432**	**-529**	**-532**	**-312**	**-484**	**-295**	**-407**	**-371**	**-333**	**-348**	**-376**	**-547**

*Note: These figures assume maximum one hour peak loads for the month and one hour hydro capabilities. September 6, 2002 load forecast.
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Table F.33
Monthly Loads & Resources Capacity Forecast – 2014 (in MW)

Year 2014	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS										2017		
Peak Load	1985	1912	1858	1677	1586	1650	1823	1775	1602	1637	1811	2001
Potlatch	54	54	54	54	54	54	54	54	54	54	54	54
CAPACITY CONTRACTS												
Black Creek Hydro	0	0	0	0	0	0	0	-10	0	0	0	0
Nichols Pumping	1	1	1	1	1	1	1	1	1	1	1	1
BPA Can. ENT> (Canada)	4	4	4	4	4	4	4	4	4	4	4	4
BPA-WNP3 Gross	-82	-82	-41	-41	0	0	0	0	0	0	-82	-82
Enron/PGE 20 Cap	150	150	150	150	150	150	150	150	150	150	150	150
Grant Displacement	0	0	0	0	0	0	0	0	0	0	0	0
Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0
BPA Residential Exchange	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL REQUIREMENTS	2112	2039	2026	1845	1795	1859	2032	1974	1811	1846	1938	2128
HYDRO RESOURCES												
System Hydro	973	972	960	959	952	971	979	978	970	969	974	976
Mid-Columbia	60	60	60	60	60	60	60	60	60	60	60	60
Small Hydro	4	4	4	4	4	4	4	4	4	4	4	4
Upriver Firm	4	4	9	16	16	12	9	3	5	7	7	6
Sub-Total	1041	1040	1033	1039	1032	1047	1052	1045	1039	1040	1045	1046
THERMAL RESOURCES												
Coyote Springs II	144	141	139	137	134	132	130	130	132	137	141	143
Colstrip	222	222	222	222	222	222	222	222	222	222	222	222
Northeast Turbine	60	59	57	56	55	55	50	50	55	56	57	60
Rathdrum CT	176	172	168	163	160	144	144	141	146	164	170	174
Boulder Park	25	25	25	25	25	25	25	25	25	25	25	25
Kettle Falls CT	7	7	7	7	7	7	7	7	7	7	7	7
Kettle Falls	50	50	50	50	50	50	50	50	50	50	50	50
Sub-Total	684	676	668	660	653	635	628	625	637	661	672	681
TOTAL RESOURCES	**1725**	**1716**	**1701**	**1699**	**1685**	**1682**	**1680**	**1670**	**1676**	**1701**	**1717**	**1727**
MAINTENANCE												
Coyote Springs II	0	0	0	0	-134	0	0	0	0	0	0	0
Spokane River	0	0	0	0	0	0	0	-15	-52	-53	-3	0
Clark Fork River	0	-166	-166	-102	0	0	0	0	-102	-102	-102	-102
Mid-Columbia	0	0	0	-17	-17	-17	0	0	0	0	0	0
Rathdrum	0	0	0	0	-80	0	0	0	0	0	0	0
Kettle Falls	0	0	0	0	0	-50	0	0	0	0	0	0
Colstrip	0	0	0	0	-111	0	0	0	0	0	0	0
Total Maintenance	0	-166	-166	-119	-342	-67	0	-15	-154	-155	-105	-102
Hydro Reserves 5% (Includes Box Canyon Gen)	55	47	47	49	54	55	56	55	48	48	50	51
Thermal Reserves 7% (Includes Vaagen Gen)	48	48	47	46	23	41	44	44	45	47	47	48
Total Reserves	104	95	94	96	77	96	100	99	93	94	98	99
	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
CAPACITY SURPLUS (DEFICIT)	**-491**	**-584**	**-585**	**-361**	**-529**	**-340**	**-452**	**-418**	**-382**	**-394**	**-424**	**-602**

*Note: These figures assume maximum one hour peak loads for the month and one hour hydro capabilities. September 6, 2002 load forecast.

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Table F.34
Monthly Loads & Resources Capacity Forecast – 2015 (in MW)

Year 2015	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS										2017		
Peak Load	2059	1980	1923	1737	1641	1706	1878	1834	1661	1694	1870	2071
Potlatch	56	56	56	56	56	56	56	56	56	56	56	56
CAPACITY CONTRACTS												
Black Creek Hydro	0	0	0	0	0	0	0	-10	0	0	0	0
Nichols Pumping	1	1	1	1	1	1	1	1	1	1	1	1
BPA Can. ENT> (Canada)	3	3	3	3	3	3	3	3	3	3	3	3
BPA-WNP3 Gross	-82	-82	-41	-41	0	0	0	0	0	0	-82	-82
Enron/PGE 20 Cap	150	150	150	150	150	150	150	150	150	150	150	150
Grant Displacement	0	0	0	0	0	0	0	0	0	0	0	0
Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0
BPA Residential Exchange	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL REQUIREMENTS	2187	2108	2092	1906	1851	1916	2088	2034	1871	1904	1998	2199
HYDRO RESOURCES												
System Hydro	973	972	960	959	952	971	979	978	970	969	974	976
Mid-Columbia	59	59	59	59	59	59	59	59	59	59	59	59
Small Hydro	4	4	4	4	4	4	4	4	4	4	4	4
Upriver Firm	4	4	9	16	16	12	9	3	5	7	7	6
Sub-Total	1040	1039	1032	1038	1031	1046	1051	1044	1038	1039	1044	1045
THERMAL RESOURCES												
Coyote Springs II	144	141	139	137	134	132	130	130	132	137	141	143
Colstrip	222	222	222	222	222	222	222	222	222	222	222	222
Northeast Turbine	60	59	57	56	55	55	50	50	55	56	57	60
Rathdrum CT	176	172	168	163	160	144	144	141	146	164	170	174
Boulder Park	25	25	25	25	25	25	25	25	25	25	25	25
Kettle Falls CT	7	7	7	7	7	7	7	7	7	7	7	7
Kettle Falls	50	50	50	50	50	50	50	50	50	50	50	50
Sub-Total	684	676	668	660	653	635	628	625	637	661	672	681
TOTAL RESOURCES	**1724**	**1715**	**1700**	**1698**	**1684**	**1681**	**1679**	**1669**	**1675**	**1700**	**1716**	**1726**
MAINTENANCE												
Coyote Springs II	0	0	0	0	-134	0	0	0	0	0	0	0
Spokane River	0	0	0	0	0	0	0	-15	-52	-53	-3	0
Clark Fork River	0	-166	-166	-102	0	0	0	0	-102	-102	-102	-102
Mid-Columbia	0	0	0	-17	-17	-17	0	0	0	0	0	0
Rathdrum	0	0	0	0	-80	0	0	0	0	0	0	0
Kettle Falls	0	0	0	0	0	-50	0	0	0	0	0	0
Colstrip	0	0	0	0	-111	0	0	0	0	0	0	0
Total Maintenance	0	-166	-166	-119	-342	-67	0	-15	-154	-155	-105	-102
Hydro Reserves 5% (Includes Box Canyon Gen)	55	47	47	49	54	55	56	55	48	48	50	51
Thermal Reserves 7% (Includes Vaagen Gen)	48	48	47	46	23	41	44	44	45	47	47	48
Total Reserves	104	95	94	96	77	96	100	99	92	94	98	99
	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
CAPACITY SURPLUS (DEFICIT)	**-567**	**-654**	**-652**	**-423**	**-586**	**-398**	**-509**	**-479**	**-442**	**-453**	**-485**	**-674**

*Note: These figures assume maximum one hour peak loads for the month and one hour hydro capabilities. September 6, 2002 load forecast.
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Table F.35
Monthly Loads & Resources Capacity Forecast – 2016 (in MW)

Year 2016	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS										2017		
Peak Load	2135	2051	1991	1799	1698	1763	1936	1894	1723	1753	1931	2142
Potlatch	56	56	56	56	56	56	56	56	56	56	56	56
CAPACITY CONTRACTS												
Black Creek Hydro	0	0	0	0	0	0	0	-10	0	0	0	0
Nichols Pumping	1	1	1	1	1	1	1	1	1	1	1	1
BPA Can. ENT> (Canada)	3	3	3	3	3	3	3	3	3	3	3	3
BPA-WNP3 Gross	-82	-82	-41	-41	0	0	0	0	0	0	-82	-82
Enron/PGE 20 Cap	150	150	150	150	150	150	150	150	150	150	150	150
Grant Displacement	0	0	0	0	0	0	0	0	0	0	0	0
Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0
BPA Residential Exchange	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL REQUIREMENTS	2263	2179	2160	1968	1908	1973	2146	2094	1933	1963	2059	2270
HYDRO RESOURCES												
System Hydro	973	972	960	959	952	971	979	978	970	969	974	976
Mid-Columbia	57	57	57	57	57	57	57	57	57	57	57	57
Small Hydro	4	4	4	4	4	4	4	4	4	4	4	4
Upriver Firm	4	4	9	16	16	12	9	3	5	7	7	6
Sub-Total	1038	1037	1030	1036	1029	1044	1049	1042	1036	1037	1042	1043
THERMAL RESOURCES												
Coyote Springs II	144	141	139	137	134	132	130	130	132	137	141	143
Colstrip	222	222	222	222	222	222	222	222	222	222	222	222
Northeast Turbine	60	59	57	56	55	55	50	50	55	56	57	60
Rathdrum CT	176	172	168	163	160	144	144	141	146	164	170	174
Boulder Park	25	25	25	25	25	25	25	25	25	25	25	25
Kettle Falls CT	7	7	7	7	7	7	7	7	7	7	7	7
Kettle Falls	50	50	50	50	50	50	50	50	50	50	50	50
Sub-Total	684	676	668	660	653	635	628	625	637	661	672	681
TOTAL RESOURCES	**1722**	**1713**	**1698**	**1696**	**1682**	**1679**	**1677**	**1667**	**1673**	**1698**	**1714**	**1724**
MAINTENANCE												
Coyote Springs II	0	0	0	0	-134	0	0	0	0	0	0	0
Spokane River	0	0	0	0	0	0	0	-15	-52	-53	-3	0
Clark Fork River	0	-166	-166	-102	0	0	0	0	-102	-102	-102	-102
Mid-Columbia	0	0	0	-16	-16	-16	0	0	0	0	0	0
Rathdrum	0	0	0	0	-80	0	0	0	0	0	0	0
Kettle Falls	0	0	0	0	0	-50	0	0	0	0	0	0
Colstrip	0	0	0	0	-111	0	0	0	0	0	0	0
Total Maintenance	0	-166	-166	-118	-341	-66	0	-15	-154	-155	-105	-102
Hydro Reserves 5% (Includes Box Canyon Gen)	55	47	47	49	54	55	56	55	48	48	50	50
Thermal Reserves 7% (Includes Vaagen Gen)	48	48	47	46	23	41	44	44	45	47	47	48
Total Reserves	103	95	94	96	77	96	100	99	92	94	98	98
	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
CAPACITY SURPLUS (DEFICIT)	**-644**	**-727**	**-722**	**-486**	**-644**	**-456**	**-569**	**-541**	**-506**	**-514**	**-548**	**-746**

*Note: These figures assume maximum one hour peak loads for the month and one hour hydro capabilities. September 6, 2002 load forecast.
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Table F.36
Monthly Loads & Resources Capacity Forecast – 2017 (in MW)

Year 2017	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS										2017		
Peak Load	2212	2122	2059	1862	1756	1821	1994	1955	1785	1812	1993	2215
Potlatch	58	58	58	58	58	58	58	58	58	58	58	58
CAPACITY CONTRACTS												
Black Creek Hydro	0	0	0	0	0	0	0	-10	0	0	0	0
Nichols Pumping	1	1	1	1	1	1	1	1	1	1	1	1
BPA Can. ENT> (Canada)	3	3	3	3	3	3	3	3	3	3	3	3
BPA-WNP3 Gross	-82	-82	-41	-41	0	0	0	0	0	0	-82	-82
Enron/PGE 20 Cap	0	0	0	0	0	0	0	0	0	0	0	0
Grant Displacement	0	0	0	0	0	0	0	0	0	0	0	0
Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0
BPA Residential Exchange	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL REQUIREMENTS	2192	2102	2080	1883	1818	1883	2056	2007	1847	1874	1973	2195
HYDRO RESOURCES												
System Hydro	973	972	960	959	952	971	979	978	970	969	974	976
Mid-Columbia	56	56	56	56	56	56	56	56	56	56	56	56
Small Hydro	4	4	4	4	4	4	4	4	4	4	4	4
Upriver Firm	4	4	9	16	16	12	9	3	5	7	7	6
Sub-Total	1037	1036	1029	1035	1028	1043	1048	1041	1035	1036	1041	1042
THERMAL RESOURCES												
Coyote Springs II	144	141	139	137	134	132	130	130	132	137	141	143
Colstrip	222	222	222	222	222	222	222	222	222	222	222	222
Northeast Turbine	60	59	57	56	55	55	50	50	55	56	57	60
Rathdrum CT	176	172	168	163	160	144	144	141	146	164	170	174
Boulder Park	25	25	25	25	25	25	25	25	25	25	25	25
Kettle Falls CT	7	7	7	7	7	7	7	7	7	7	7	7
Kettle Falls	50	50	50	50	50	50	50	50	50	50	50	50
Sub-Total	684	676	668	660	653	635	628	625	637	661	672	681
TOTAL RESOURCES	**1721**	**1712**	**1697**	**1695**	**1681**	**1678**	**1676**	**1666**	**1672**	**1697**	**1713**	**1723**
MAINTENANCE												
Coyote Springs II	0	0	0	0	-134	0	0	0	0	0	0	0
Spokane River	0	0	0	0	0	0	0	-15	-52	-53	-3	0
Clark Fork River	0	-166	-166	-102	0	0	0	0	-102	-102	-102	-102
Mid-Columbia	0	0	0	-16	-16	-16	0	0	0	0	0	0
Rathdrum	0	0	0	0	-80	0	0	0	0	0	0	0
Kettle Falls	0	0	0	0	0	-50	0	0	0	0	0	0
Colstrip	0	0	0	0	-111	0	0	0	0	0	0	0
Total Maintenance	0	-166	-166	-118	-341	-66	0	-15	-154	-155	-105	-102
Hydro Reserves 5% (Includes Box Canyon Gen)	55	47	47	49	54	55	56	55	47	47	50	50
Thermal Reserves 7% (Includes Vaagen Gen)	48	48	47	46	23	41	44	44	45	47	47	48
Total Reserves	103	95	94	96	77	96	100	99	92	94	98	98
	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
CAPACITY SURPLUS (DEFICIT)	**-574**	**-651**	**-643**	**-402**	**-555**	**-367**	**-480**	**-455**	**-421**	**-426**	**-463**	**-672**

*Note: These figures assume maximum one hour peak loads for the month and one hour hydro capabilities. September 6, 2002 load forecast.
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Table F.37
Monthly Loads & Resources Capacity Forecast – 2018 (in MW)

Year 2018	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS										2017		
Peak Load	2291	2196	2130	1927	1815	1880	2054	2018	1849	1873	2057	2289
Potlatch	58	58	58	58	58	58	58	58	58	58	58	58
CAPACITY CONTRACTS												
Black Creek Hydro	0	0	0	0	0	0	0	-10	0	0	0	0
Nichols Pumping	1	1	1	1	1	1	1	1	1	1	1	1
BPA Can. ENT> (Canada)	3	3	3	3	3	3	3	3	3	1	1	1
BPA-WNP3 Gross	-82	-82	-41	-41	0	0	0	0	0	0	-82	-82
Enron/PGE 20 Cap	0	0	0	0	0	0	0	0	0	0	0	0
Grant Displacement	0	0	0	0	0	0	0	0	0	0	0	0
Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0
BPA Residential Exchange	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL REQUIREMENTS	2271	2176	2151	1948	1877	1942	2116	2070	1911	1933	2035	2267
HYDRO RESOURCES												
System Hydro	973	972	960	959	952	971	979	978	970	969	974	976
Mid-Columbia	54	54	54	54	54	54	54	54	54	25	25	25
Small Hydro	4	4	4	4	4	4	4	4	4	4	4	4
Upriver Firm	4	4	9	16	16	12	9	3	5	7	7	6
Sub-Total	1035	1034	1027	1033	1026	1041	1046	1039	1033	1005	1010	1011
THERMAL RESOURCES												
Coyote Springs II	144	141	139	137	134	132	130	130	132	137	141	143
Colstrip	222	222	222	222	222	222	222	222	222	222	222	222
Northeast Turbine	60	59	57	56	55	55	50	50	55	56	57	60
Rathdrum CT	176	172	168	163	160	144	144	141	146	164	170	174
Boulder Park	25	25	25	25	25	25	25	25	25	25	25	25
Kettle Falls CT	7	7	7	7	7	7	7	7	7	7	7	7
Kettle Falls	50	50	50	50	50	50	50	50	50	50	50	50
Sub-Total	684	676	668	660	653	635	628	625	637	661	672	681
TOTAL RESOURCES	**1719**	**1710**	**1695**	**1693**	**1679**	**1676**	**1674**	**1664**	**1670**	**1666**	**1682**	**1692**
MAINTENANCE												
Coyote Springs II	0	0	0	0	-134	0	0	0	0	0	0	0
Spokane River	0	0	0	0	0	0	0	-15	-52	-53	-3	0
Clark Fork River	0	-166	-166	-102	0	0	0	0	-102	-102	-102	-102
Mid-Columbia	0	0	0	-15	-15	-15	0	0	0	0	0	0
Rathdrum	0	0	0	0	-80	0	0	0	0	0	0	0
Kettle Falls	0	0	0	0	0	-50	0	0	0	0	0	0
Colstrip	0	0	0	0	-111	0	0	0	0	0	0	0
Total Maintenance	0	-166	-166	-117	-340	-65	0	-15	-154	-155	-105	-102
Hydro Reserves 5% (Includes Box Canyon Gen)	55	47	46	49	54	55	56	55	47	46	49	49
Thermal Reserves 7% (Includes Vaagen Gen)	48	48	47	46	23	41	44	44	45	47	47	48
Total Reserves	103	94	93	96	77	96	100	99	92	92	96	97
	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
CAPACITY SURPLUS (DEFICIT)	**-655**	**-726**	**-715**	**-468**	**-615**	**-427**	**-542**	**-520**	**-487**	**-514**	**-554**	**-774**

*Note: These figures assume maximum one hour peak loads for the month and one hour hydro capabilities. September 6, 2002 load forecast.
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Table F.38
Monthly Loads & Resources Capacity Forecast – 2019 (in MW)

Year 2019	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS										2017		
Peak Load	2365	2264	2195	1987	1871	1935	2110	2076	1909	1930	2116	2358
Potlatch	60	60	60	60	60	60	60	60	60	60	60	60
CAPACITY CONTRACTS												
Black Creek Hydro	0	0	0	0	0	0	0	-10	0	0	0	0
Nichols Pumping	1	1	1	1	1	1	1	1	1	1	1	1
BPA Can. ENT> (Canada)	1	1	1	1	1	1	1	1	1	1	1	1
BPA-WNP3 Gross	-82	-82	-41	-41	0	0	0	0	0	0	0	0
Enron/PGE 20 Cap	0	0	0	0	0	0	0	0	0	0	0	0
Grant Displacement	0	0	0	0	0	0	0	0	0	0	0	0
Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0
BPA Residential Exchange	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL REQUIREMENTS	2345	2244	2216	2008	1933	1997	2172	2128	1971	1992	2178	2420
HYDRO RESOURCES												
System Hydro	973	972	960	959	952	971	979	978	970	969	974	976
Mid-Columbia	24	24	24	24	24	24	24	24	24	24	24	24
Small Hydro	4	4	4	4	4	4	4	4	4	4	4	4
Upriver Firm	4	4	9	16	16	12	9	3	5	7	7	6
Sub-Total	1005	1004	997	1003	996	1011	1016	1009	1003	1004	1009	1010
THERMAL RESOURCES												
Coyote Springs II	144	141	139	137	134	132	130	130	132	137	141	143
Colstrip	222	222	222	222	222	222	222	222	222	222	222	222
Northeast Turbine	60	59	57	56	55	55	50	50	55	56	57	60
Rathdrum CT	176	172	168	163	160	144	144	141	146	164	170	174
Boulder Park	25	25	25	25	25	25	25	25	25	25	25	25
Kettle Falls CT	7	7	7	7	7	7	7	7	7	7	7	7
Kettle Falls	50	50	50	50	50	50	50	50	50	50	50	50
Sub-Total	684	676	668	660	653	635	628	625	637	661	672	681
TOTAL RESOURCES	**1689**	**1680**	**1665**	**1663**	**1649**	**1646**	**1644**	**1634**	**1640**	**1665**	**1681**	**1691**
MAINTENANCE												
Coyote Springs II	0	0	0	0	-134	0	0	0	0	0	0	0
Spokane River	0	0	0	0	0	0	0	-15	-52	-53	-3	0
Clark Fork River	0	-166	-166	-102	0	0	0	0	-102	-102	-102	-102
Mid-Columbia	0	0	0	-7	-7	-7	0	0	0	0	0	0
Rathdrum	0	0	0	0	-80	0	0	0	0	0	0	0
Kettle Falls	0	0	0	0	0	-50	0	0	0	0	0	0
Colstrip	0	0	0	0	-111	0	0	0	0	0	0	0
Total Maintenance	0	-166	-166	-109	-332	-57	0	-15	-154	-155	-105	-102
Hydro Reserves 5% (Includes Box Canyon Gen)	54	45	45	48	53	54	54	53	46	46	49	49
Thermal Reserves 7% (Includes Vaagen Gen)	48	48	47	46	23	41	44	44	45	47	47	48
Total Reserves	102	93	92	95	76	95	98	97	91	92	96	97
	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
CAPACITY SURPLUS (DEFICIT)	**-758**	**-823**	**-809**	**-549**	**-692**	**-503**	**-626**	**-606**	**-576**	**-574**	**-698**	**-928**

*Note: These figures assume maximum one hour peak loads for the month and one hour hydro capabilities. September 6, 2002 load forecast.
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Table F.39
Monthly Loads & Resources Capacity Forecast – 2020 (in MW)

Year 2020	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS										2017		
Peak Load	2441	2335	2263	2050	1928	1993	2167	2137	1971	1989	2178	2430
Potlatch	60	60	60	60	60	60	60	60	60	60	60	60
CAPACITY CONTRACTS												
Black Creek Hydro	0	0	0	0	0	0	0	-10	0	0	0	0
Nichols Pumping	1	1	1	1	1	1	1	1	1	1	1	1
BPA Can. ENT> (Canada)	1	1	1	1	1	1	1	1	1	1	1	1
BPA-WNP3 Gross	0	0	0	0	0	0	0	0	0	0	0	0
Enron/PGE 20 Cap	0	0	0	0	0	0	0	0	0	0	0	0
Grant Displacement	0	0	0	0	0	0	0	0	0	0	0	0
Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0
BPA Residential Exchange	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL REQUIREMENTS	2503	2397	2325	2112	1990	2055	2229	2189	2033	2051	2240	2492
HYDRO RESOURCES												
System Hydro	973	972	960	959	952	971	979	978	970	969	974	976
Mid-Columbia	22	22	22	22	22	22	22	22	22	22	22	22
Small Hydro	4	4	4	4	4	4	4	4	4	4	4	4
Upriver Firm	4	4	9	16	16	12	9	3	5	7	7	6
Sub-Total	1003	1002	995	1001	994	1009	1014	1007	1001	1002	1007	1008
THERMAL RESOURCES												
Coyote Springs II	144	141	139	137	134	132	130	130	132	137	141	143
Colstrip	222	222	222	222	222	222	222	222	222	222	222	222
Northeast Turbine	60	59	57	56	55	55	50	50	55	56	57	60
Rathdrum CT	176	172	168	163	160	144	144	141	146	164	170	174
Boulder Park	25	25	25	25	25	25	25	25	25	25	25	25
Kettle Falls CT	7	7	7	7	7	7	7	7	7	7	7	7
Kettle Falls	50	50	50	50	50	50	50	50	50	50	50	50
Sub-Total	684	676	668	660	653	635	628	625	637	661	672	681
TOTAL RESOURCES	**1687**	**1678**	**1663**	**1661**	**1647**	**1644**	**1642**	**1632**	**1638**	**1663**	**1679**	**1689**
MAINTENANCE												
Coyote Springs II	0	0	0	0	-134	0	0	0	0	0	0	0
Spokane River	0	0	0	0	0	0	0	-15	-52	-53	-3	0
Clark Fork River	0	-166	-166	-102	0	0	0	0	-102	-102	-102	-102
Mid-Columbia	0	0	0	-6	-6	-6	0	0	0	0	0	0
Rathdrum	0	0	0	0	-80	0	0	0	0	0	0	0
Kettle Falls	0	0	0	0	0	-50	0	0	0	0	0	0
Colstrip	0	0	0	0	-111	0	0	0	0	0	0	0
Total Maintenance	0	-166	-166	-108	-331	-56	0	-15	-154	-155	-105	-102
Hydro Reserves 5% (Includes Box Canyon Gen)	54	45	45	48	53	54	54	53	46	46	49	49
Thermal Reserves 7% (Includes Vaagen Gen)	48	48	47	46	23	41	44	44	45	47	47	48
Total Reserves	102	93	92	95	76	95	98	97	91	92	96	97
	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
CAPACITY SURPLUS (DEFICIT)	**-918**	**-978**	**-920**	**-654**	**-750**	**-562**	**-685**	**-669**	**-640**	**-635**	**-762**	**-1002**

*Note: These figures assume maximum one hour peak loads for the month and one hour hydro capabilities. September 6, 2002 load forecast.
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Table F.40
Monthly Loads & Resources Capacity Forecast – 2021 (in MW)

Year 2021	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS										2017		
Peak Load	2530	2417	2342	2122	1994	2059	2234	2207	2042	2057	2249	2513
Potlatch	62	62	62	62	62	62	62	62	62	62	62	62
CAPACITY CONTRACTS												
Black Creek Hydro	0	0	0	0	0	0	0	-10	0	0	0	0
Nichols Pumping	1	1	1	1	1	1	1	1	1	1	1	1
BPA Can. ENT> (Canada)	1	1	1	1	1	1	1	1	1	1	1	1
BPA-WNP3 Gross	0	0	0	0	0	0	0	0	0	0	0	0
Enron/PGE 20 Cap	0	0	0	0	0	0	0	0	0	0	0	0
Grant Displacement	0	0	0	0	0	0	0	0	0	0	0	0
Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0
BPA Residential Exchange	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL REQUIREMENTS	2594	2481	2406	2186	2058	2123	2298	2261	2106	2121	2313	2577
HYDRO RESOURCES												
System Hydro	973	972	960	959	952	971	979	978	970	969	974	976
Mid-Columbia	21	21	21	21	21	21	21	21	21	21	21	21
Small Hydro	4	4	4	4	4	4	4	4	4	4	4	4
Upriver Firm	4	4	9	16	16	12	9	3	5	7	7	6
Sub-Total	1002	1001	994	1000	993	1008	1013	1006	1000	1001	1006	1007
THERMAL RESOURCES												
Coyote Springs II	144	141	139	137	134	132	130	130	132	137	141	143
Colstrip	222	222	222	222	222	222	222	222	222	222	222	222
Northeast Turbine	60	59	57	56	55	55	50	50	55	56	57	60
Rathdrum CT	176	172	168	163	160	144	144	141	146	164	170	174
Boulder Park	25	25	25	25	25	25	25	25	25	25	25	25
Kettle Falls CT	7	7	7	7	7	7	7	7	7	7	7	7
Kettle Falls	50	50	50	50	50	50	50	50	50	50	50	50
Sub-Total	684	676	668	660	653	635	628	625	637	661	672	681
TOTAL RESOURCES	**1686**	**1677**	**1662**	**1660**	**1646**	**1643**	**1641**	**1631**	**1637**	**1662**	**1678**	**1688**
MAINTENANCE												
Coyote Springs II	0	0	0	0	-134	0	0	0	0	0	0	0
Spokane River	0	0	0	0	0	0	0	-15	-52	-53	-3	0
Clark Fork River	0	-166	-166	-102	0	0	0	0	-102	-102	-102	-102
Mid-Columbia	0	0	0	-6	-6	-6	0	0	0	0	0	0
Rathdrum	0	0	0	0	-80	0	0	0	0	0	0	0
Kettle Falls	0	0	0	0	0	-50	0	0	0	0	0	0
Colstrip	0	0	0	0	-111	0	0	0	0	0	0	0
Total Maintenance	0	-166	-166	-108	-331	-56	0	-15	-154	-155	-105	-102
Hydro Reserves 5% (Includes Box Canyon Gen)	54	45	45	48	53	54	54	53	46	46	48	49
Thermal Reserves 7% (Includes Vaagen Gen)	48	48	47	46	23	41	44	44	45	47	47	48
Total Reserves	102	93	92	94	76	95	98	97	91	92	96	97
	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
CAPACITY SURPLUS (DEFICIT)	**-1010**	**-1063**	**-1002**	**-728**	**-819**	**-631**	**-755**	**-742**	**-714**	**-706**	**-836**	**-1088**

*Note: These figures assume maximum one hour peak loads for the month and one hour hydro capabilities. September 6, 2002 load forecast.
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Table F.41
Monthly Loads & Resources Capacity Forecast – 2022 (in MW)

Year 2022	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS										2017		
Peak Load	2625	2506	2426	2200	2065	2131	2306	2283	2119	2130	2325	2603
Potlatch	62	62	62	62	62	62	62	62	62	62	62	62
CAPACITY CONTRACTS												
Black Creek Hydro	0	0	0	0	0	0	0	-10	0	0	0	0
Nichols Pumping	1	1	1	1	1	1	1	1	1	1	1	1
BPA Can. ENT> (Canada)	1	1	1	1	1	1	1	1	1	1	1	1
BPA-WNP3 Gross	0	0	0	0	0	0	0	0	0	0	0	0
Enron/PGE 20 Cap	0	0	0	0	0	0	0	0	0	0	0	0
Grant Displacement	0	0	0	0	0	0	0	0	0	0	0	0
Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0
BPA Residential Exchange	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL REQUIREMENTS	2689	2570	2490	2264	2129	2195	2370	2337	2183	2194	2389	2667
HYDRO RESOURCES												
System Hydro	973	972	960	959	952	971	979	978	970	969	974	976
Mid-Columbia	19	19	19	19	19	19	19	19	19	19	19	19
Small Hydro	4	4	4	4	4	4	4	4	4	4	4	4
Upriver Firm	4	4	9	16	16	12	9	3	5	7	7	6
Sub-Total	1000	999	992	998	991	1006	1011	1004	998	999	1004	1005
THERMAL RESOURCES												
Coyote Springs II	144	141	139	137	134	132	130	130	132	137	141	143
Colstrip	222	222	222	222	222	222	222	222	222	222	222	222
Northeast Turbine	60	59	57	56	55	55	50	50	55	56	57	60
Rathdrum CT	176	172	168	163	160	144	144	141	146	164	170	174
Boulder Park	25	25	25	25	25	25	25	25	25	25	25	25
Kettle Falls CT	7	7	7	7	7	7	7	7	7	7	7	7
Kettle Falls	50	50	50	50	50	50	50	50	50	50	50	50
Sub-Total	684	676	668	660	653	635	628	625	637	661	672	681
TOTAL RESOURCES	**1684**	**1675**	**1660**	**1658**	**1644**	**1641**	**1639**	**1629**	**1635**	**1660**	**1676**	**1686**
MAINTENANCE												
Coyote Springs II	0	0	0	0	-134	0	0	0	0	0	0	0
Spokane River	0	0	0	0	0	0	0	-15	-52	-53	-3	0
Clark Fork River	0	-166	-166	-102	0	0	0	0	-102	-102	-102	-102
Mid-Columbia	0	0	0	-5	-5	-5	0	0	0	0	0	0
Rathdrum	0	0	0	0	-80	0	0	0	0	0	0	0
Kettle Falls	0	0	0	0	0	-50	0	0	0	0	0	0
Colstrip	0	0	0	0	-111	0	0	0	0	0	0	0
Total Maintenance	0	-166	-166	-107	-330	-55	0	-15	-154	-155	-105	-102
Hydro Reserves 5% (Includes Box Canyon Gen)	53	45	45	48	53	53	54	53	46	46	48	49
Thermal Reserves 7% (Includes Vaagen Gen)	48	48	47	46	23	41	44	44	45	47	47	48
Total Reserves	102	93	92	94	76	95	98	97	90	92	96	97
	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
CAPACITY SURPLUS (DEFICIT)	**-1107**	**-1154**	**-1088**	**-807**	**-891**	**-704**	**-829**	**-820**	**-792**	**-781**	**-914**	**-1180**

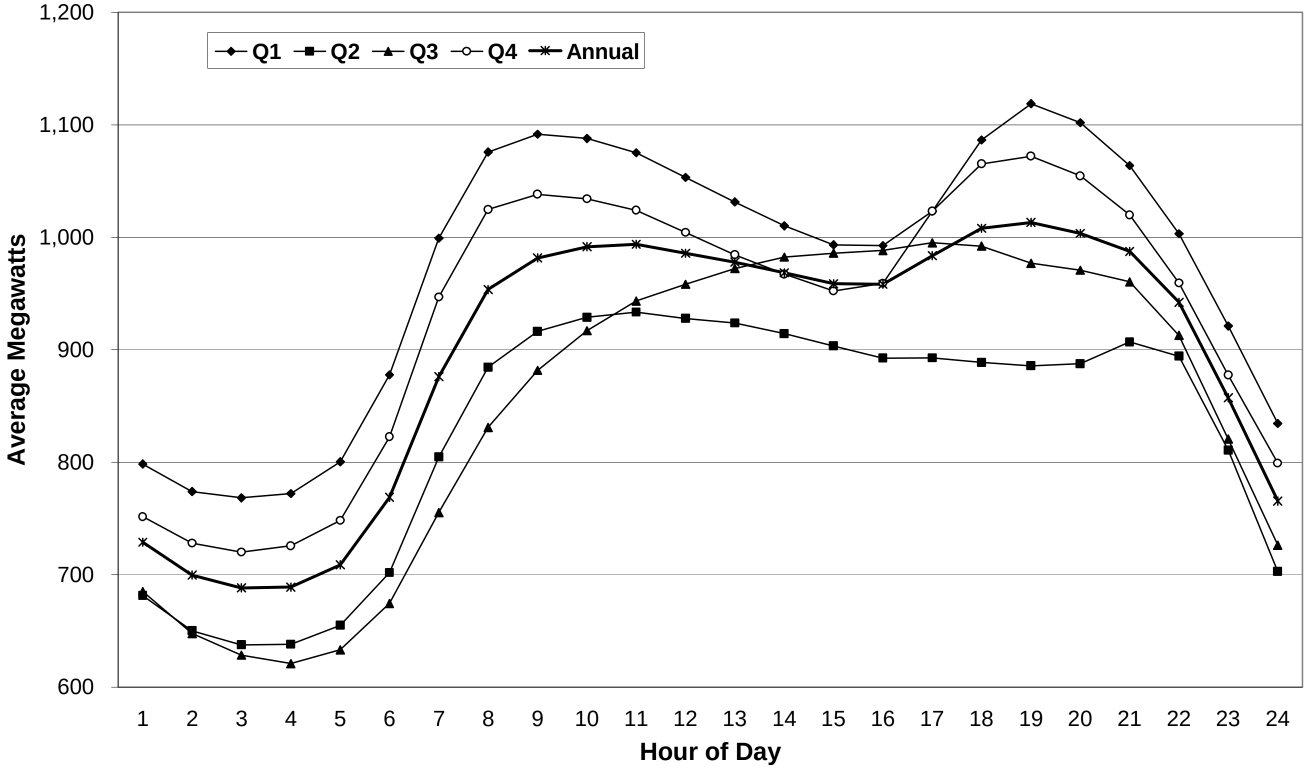
*Note: These figures assume maximum one hour peak loads for the month and one hour hydro capabilities. September 6, 2002 load forecast.
Revision No. 11 January 10, 2003 Doug Young

Table F.42
Monthly Loads & Resources Capacity Forecast – 2023 (in MW)

Year 2023	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LOADS										2017		
Peak Load	2716	2591	2507	2275	2133	2199	2374	2355	2193	2200	2398	2688
Potlatch	64	64	64	64	64	64	64	64	64	64	64	64
CAPACITY CONTRACTS												
Black Creek Hydro	0	0	0	0	0	0	0	-10	0	0	0	0
Nichols Pumping	1	1	1	1	1	1	1	1	1	1	1	1
BPA Can. ENT> (Canada)	1	1	1	1	1	1	1	1	1	1	1	1
BPA-WNP3 Gross	0	0	0	0	0	0	0	0	0	0	0	0
Enron/PGE 20 Cap	0	0	0	0	0	0	0	0	0	0	0	0
Grant Displacement	0	0	0	0	0	0	0	0	0	0	0	0
Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0
BPA Residential Exchange	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL REQUIREMENTS	2782	2657	2573	2341	2199	2265	2440	2411	2259	2266	2464	2754
HYDRO RESOURCES												
System Hydro	973	972	960	959	952	971	979	978	970	969	974	976
Mid-Columbia	17	17	17	17	17	17	17	17	17	17	17	17
Small Hydro	4	4	4	4	4	4	4	4	4	4	4	4
Upriver Firm	4	4	9	16	16	12	9	3	5	7	7	6
Sub-Total	998	997	990	996	989	1004	1009	1002	996	997	1002	1003
THERMAL RESOURCES												
Coyote Springs II	144	141	139	137	134	132	130	130	132	137	141	143
Colstrip	222	222	222	222	222	222	222	222	222	222	222	222
Northeast Turbine	60	59	57	56	55	55	50	50	55	56	57	60
Rathdrum CT	176	172	168	163	160	144	144	141	146	164	170	174
Boulder Park	25	25	25	25	25	25	25	25	25	25	25	25
Kettle Falls CT	7	7	7	7	7	7	7	7	7	7	7	7
Kettle Falls	50	50	50	50	50	50	50	50	50	50	50	50
Sub-Total	684	676	668	660	653	635	628	625	637	661	672	681
TOTAL RESOURCES	**1682**	**1673**	**1658**	**1656**	**1642**	**1639**	**1637**	**1627**	**1633**	**1658**	**1674**	**1684**
MAINTENANCE												
Coyote Springs II	0	0	0	0	-134	0	0	0	0	0	0	0
Spokane River	0	0	0	0	0	0	0	-15	-52	-53	-3	0
Clark Fork River	0	-166	-166	-102	0	0	0	0	-102	-102	-102	-102
Mid-Columbia	0	0	0	-5	-5	-5	0	0	0	0	0	0
Rathdrum	0	0	0	0	-80	0	0	0	0	0	0	0
Kettle Falls	0	0	0	0	0	-50	0	0	0	0	0	0
Colstrip	0	0	0	0	-111	0	0	0	0	0	0	0
Total Maintenance	0	-166	-166	-107	-330	-55	0	-15	-154	-155	-105	-102
Hydro Reserves 5% (Includes Box Canyon Gen)	53	45	45	48	53	53	54	53	46	46	48	48
Thermal Reserves 7% (Includes Vaagen Gen)	48	48	47	46	23	41	44	44	45	47	47	48
Total Reserves	101	93	92	94	76	95	98	97	90	92	96	96
	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
CAPACITY SURPLUS (DEFICIT)	**-1201**	**-1243**	**-1173**	**-886**	**-963**	**-776**	**-901**	**-896**	**-870**	**-855**	**-991**	**-1268**

*Note: These figures assume maximum one hour peak loads for the month and one hour hydro capabilities. September 6, 2002 load forecast.
Revision No. 11 January 10, 2003 Doug Young

Chart F.6
2002 Hourly System Load Shapes by Quarter



Appendix

G TAC Meeting Agendas

May 2, 2002

1. Annual L&R Tabulation
2. Report Outline-Draft
3. Update on New Resources
4. Natural Gas Outlook
5. Confidence Interval Planning Concept
6. Meeting Intermediate Resource Needs
7. Company Structure for the Future
8. DSM Update/ EEE Overview
9. Model Use – Prosym/ Aurora
10. Scenarios for Load Forecast

September 24, 2002

1. Electric and Natural Gas Forecasts
2. Gas Outlook and Price Forecast
3. Gas and Electric DSM Plans
4. Electric Modeling Enhancements

January 23, 2003

1. WECC Marketplace
   - Capacity Expansion/ Natural Gas Forecast/ Price Forecast
   - Avista's Outlook/ Resource Alternatives
2. Risk Analysis
   - Load, Hydro, Natural Gas, and Price Variability
3. Avista's Microturbine
4. Spokane River Relicensing

April 2, 2003

1. Accomplishments Since the last Meeting
2. TAC Members Review
3. Schedule to Finalize the Report
4. Report's Inputs
5. Report's Chapter Reviews
6. Final Results
7. Impacts on Avista and its Customers
8. Information in Appendices

Appendix

H

Wind Studies

Wind Energy

Wind energy has become more prominent in the Northwest in recent years due to three primary drivers: a federal energy tax credits which reduces the cost of the plants by nearly one-third; falling capital costs from new and better technologies and economies of scale; and legislative pushes such as renewable portfolio standards, which have resulted from environmental activism. There is nearly 500 MW (160 aMW of energy) of wind generation facilities presently installed or in construction in the Northwest.

The Company recognizes these changes and has begun evaluating the potential for wind energy on its system. Its preferred resource strategy includes 75 MW installed early in the acquisition timeframe. Preliminary studies have verified that wind energy costs have indeed fallen tremendously; however, system integration issues and costs caution the Company against moving too fast. This section will summarize preliminary findings of an internal Company study.

The Falling Costs of Wind Energy

Similar to generation technologies before it, wind generation plant costs have fallen to around $1,000/kW, a fraction of what prices were a decade ago. Turbines are now much larger, are based on simpler designs, and benefit from economies of scale as countries around the world install the plants. Most significant development prior to the late-1990s was found in Europe, where higher energy costs made the turbines more attractive relative to the United States where electricity is comparatively less expensive. The Company estimates that with current federal tax credit levels, wind energy plants can be installed and operated at a cost of approximately $35/MWh in real levelized 2004 dollars, excluding integration and transmission expenses.

System Integration

One cost that has not fallen, and in fact may be rising due to increasingly constrained transmission and hydro facilities, is system integration. All generation facilities must pay integration charges in addition to their installation and operation. At a minimum, a plant must purchase transmission to deliver its energy to a load center. A plant is also responsible for various reserve products to protect the grid against forced outages. System integration costs appear to be much higher for wind energy plants than other generation resources.

Traditional generation resources, while varying somewhat based on technology, benefit from having fuel supplies that are predictable and controllable for hours, even days or months, ahead of scheduled delivery. For example, a coal plant can have not only a predictable schedule of fuel deliveries, but also a large storage pile in the event that deliveries are interrupted for a period of time. Hydroelectric projects might or might not have significant storage capabilities, but nearly all can be scheduled no less than on a pre-schedule or hour-ahead basis.

Traditional resources benefit from predictability. Wind, on the other hand, does not. An installation of 100 MW has the potential on a given hour to generate somewhere between zero and 100 MW. Unfortunately, this schedule is not as predictable as other sources of power. Wind is not controllable in that Mother Nature decides when and how much energy will be generated. This lack of predictability and control puts wind plants at a significant disadvantage. Third-party estimates of wind integration costs have been put as high as $25 per MWh.

"Fuel" Availability

A second large disadvantage of wind plants is a lack of fuel availability. An exceptional Northwest wind site can expect to have somewhere in the neighborhood of a 30 to 35 percent fuel availability. While the wind generators themselves might be available to generate for 95 percent or more of the hours during a year, there is not enough wind to keep the plants operating at high levels. This low fuel availability puts wind energy plants at a disadvantage on a cost per MWh basis. For example, a one megawatt wind or gas turbine plant with a fifteen percent capital recovery factor would incur an annual fixed expense of $150,000 assuming a $1,000/kW installed cost. The wind plant would be expected to generate 2,980 MWh during the year assuming a 33 percent fuel availability factor. The gas turbine plant with an identical installed cost, on the other hand, would be capable of generating 8,322 MWh assuming a five percent forced outage rate. On a per-MWh basis, capital recovery costs for the wind plant would be $50.3 per MWh; the gas turbine plant would be $18.0 per MWh, or one-third as much.

Fuel Costs

The largest economic benefit of wind energy is that its fuel is free. While the variable operating and maintenance costs are similar to that of a natural gas-fired turbine, such savings can be significant. At $4 per decatherm, fuel costs for an efficient CCCT are $28 per MWh. Where gas prices are higher, the benefit of a wind turbine increases further. Of course, natural gas prices can also be lower, reducing the advantage of wind energy during those periods.

Another advantage of wind plants, and other low fuel cost facilities (e.g., mine-mouth coal plants), is their hedge against natural gas price volatility. Utilities have long recognized the benefits of generation portfolios with diverse fuel sources. The Company's hydroelectric dams provide a similar benefit. Wind energy provides a strong hedge against natural gas price swings. In fact, wind energy portfolios evaluated in the Company's IRP had the lowest financial risk.

Environmental Benefits

Wind energy plants are a renewable resource and do not emit pollutants into the environment. Impacts are modest when compared to other technologies, and in many cases have been addressed. For example, early concerns over bird kills have been all but eliminated by avoiding migratory bird paths. While wind plants "consume" large tracts of land, these sites traditionally are in remote areas where their installation does not tremendously affect other activities (e.g., farming).

Wind Energy Generation and Consideration of Capacity

The Company, as a hydro-dependent utility, is acutely aware of issues surrounding energy-limited resources. Hydroelectric plants generally have very high capacities over a short timeframe such as an hour. However, sustained capacity over many hours and days cannot be planned for once storage water is gone.

A similar concept applies to wind generators. While wind generators have energy associated with them, there is no means to reliably forecast generation more than a few hours ahead. Because of this lack of predictability, the Company was concerned about including wind generation in its capacity tabulations. To determine the potential for counting wind generator capacity in its capacity tabulation, the Company reviewed a 25-year database of Northwest wind sites from Oregon State University. On a statistical basis it was found that wind generators do not provide any capacity. This result was the same when considering one wind site or a diverse mix of sites across the Northwest. This last point is significant. Many in the Northwest believe that while one wind site doesn't provide any guarantee of generation in a given hour, a mix of sites does. The Company took a hypothetical 20 percent share in five Northwest sites across Washington, Oregon, Idaho, and Montana. The result was the same for the diversified mix–no guarantee of capacity.

In addition to evaluating hourly capacity values, the Company reviewed the database to learn if it could on a statistical basis rely on wind generators to provide some significant level of generation over a weekly period. A week coincides well with the Company's hydro storage management, and a minimum level of expected energy generating capability would allow wind's integration into the weekly operating plan. Unfortunately, when reviewing 1994-2000 datasets, it was learned that the Company couldn't rely on wind generators to provide any significant portion of their generating capability during a specific week.

These analyses highlight the apparent fact that any utility relying on wind energy not include wind generator capacity in their capacity plans. Systems using wind energy will require other generation resources capable of meeting the varying wind generator output. In the short term this could mean relying on existing facilities at modest incremental cost. However, over the longer-run it is likely that integrating wind energy will require additional capacity resources that's cost will be incurred by ratepayers.

Utility-Specific Issues

The Company recognizes the various benefits of wind energy, but after careful review has determined that it will not rely too heavily on it without further study. System integration issues appear to be significant, both in absolute cost and the physical capability of the Company's generation system to accept its varying production. System integration is the largest single barrier to a greater reliance on wind energy. To the extent the issues can be resolved through further study, the Company sees the potential to rely upon this renewable resource for more of its future requirements.

In late 2002 the Company joined a wind developer to create a wind integration model. The model provides a simplified representation of system generators, transmission, and market hubs. A specific advantage of this new approach is that reserve products, and AGC-responsive reserves specifically, are represented in an attempt to account for "opportunity costs". Opportunity costs the Company would incur from wind integration come from less-efficient turbine operations, reduced on-peak generation levels due to carrying additional reserves, selling into less advantageous marketplaces due to constrained transmission paths and water spilled when the system has no other means to integrate wind energy.

Wind integration will require the host utility to manage its various generation turbines in configurations that are sub-optimal and outside their most efficient range. While many of the Company's generating turbines are capable of being responsive to some level of wind energy, their efficiencies can vary by ten percent or more across their operating range. Control areas oftentimes are obligated to operate in this manner with costs higher than they otherwise would be, but wind integration will increase the frequency of these periods significantly as the system moves in response to the level of wind generation on the system.

Wind energy output can vary tremendously during the day. Its output varies tremendously more, and with less predictability, than load variation. To integrate wind, then, the Company will be required to hold more turbines on AGC to provide for when wind doesn't generated as scheduled. Additional AGC reserves are the most expensive reserves that the Company has to provide and are generally carried by hydroelectric generators. Carrying AGC reserves means that turbines are not available to generate at their full level during "super-peak" periods of the day. Super-peak periods generally are in the mid-morning and late afternoon, when prices in the marketplace are the highest. Instead of generating during these hours, wind energy reserves will require hydro plant generators to generate in less valuable times of the day.

A third cost to the Company is expected to come from constrained transmission. The Company at many times during the year uses the full capability of its transmission rights to deliver energy either to its system or to a major market trading hub. When the Company has used all of its transmission rights, it must either purchase additional rights or in a worst case sell its energy to less-valuable marketplaces. Wind energy can require a large transmission reservation, as its capacity is three times greater than its expected energy output. This requirement will necessarily push the Company out into the non-firm transmission market on more occasions and also prevent energy from always being delivered to the highest-price marketplace.

In the worst case, the Company could spill water to manage a varying wind energy plant. In this case, however, the value of the wind energy is zero because it is being offset by lost water that otherwise would be generated by a hydro plant. The Company would spill only under the worst of conditions and consider this a last resort.

The impacts of these costs on some days are modest while on others are more significant. The model provides a tally of them over a typical year, a critical water year, and an above-average hydro year. Additionally, the model looks at integrating varying levels of wind energy on the Company's system. The resultant estimated costs are substantial, with costs rising above ten dollars per MWh under various potential scenarios. The model explains that the level of forecasting error and size of the installation make very large impacts on integration costs. The table below explains that forecast error is very important when scheduling wind. With perfect forecasting, integration costs are below $3/MWh. However, as the forecast becomes less accurate, prices rise substantially. A persistence forecast (what happened last hour is what will happen this hour) has costs as much as six times a "perfect" forecast.

Table H.1
Preliminary Wind Integration Cost Estimates

Model Type	Forecast Error (90% CI)	Hydro Year Wet ($/MWh)	Normal ($/MWh)	Dry ($/MWh)
Persistence	30.0%	17.66	13.56	8.34
Meso-Scale	15.0%	7.65	5.55	4.77
7.5% Error	7.5%	4.90	3.63	3.28
Perfect Forecast	0.0%	2.70	2.23	1.88

A 300 MW plant would have even larger costs. Although the Company was unable to complete runs at 300 MW except for a perfect forecast, integration costs were found to increase by a third or more.

Modeling provides one look at potential system integration issues. Internal discussions within the Company have identified operational considerations potentially beyond the breadth of the study. Although the model purports to address the additional costs associated with bringing larger quantities of wind energy into the Company's system, real-time operations could limit the amount further. Discussions with other utilities integrating wind energy explain that doing so is not a simple task. Additional scheduling staff likely will be needed. Operations will become much more unpredictable. Therefore, although the model might suggest that as much as 300 MW of wind generation could be installed, the Company cannot at this time support that conclusion.

Conclusions and Next Steps

The Company is both excited and concerned about the potential for wind generation in the Northwest. On the one hand costs have fallen tremendously over the past couple decades, making this renewable resource attractive with other traditional resources. On the other, wind integration costs haven't gone away and will likely be significant. The results of this study should be considered preliminary, as the Company has additional work to perform before it can be certain its results are comprehensive. As indicated in the Action Plan of the IRP, the Company over the next two years will perform additional studies to ensure that the full potential and costs of wind energy are recognized. After this study the Company should be better prepared to evaluate the resource against more traditional plants.

Avista Utilities

Interoffice Memorandum
Energy Resources

DATE: February 5, 2002

TO: Clint Kalich

FROM: Brad Simcox

SUBJECT: Wind Power Study

Introduction

This study began with the intention of analyzing the reliability of wind power. By using actual wind-speed information to calculate theoretical generation data, we have been able to estimate the energy that wind power could add to our system portfolio. On average, we can expect average capacity factor over the year of 15 - 30%.

Discussion

We were able to obtain a large amount of wind-speed data from Stel Walker, the director of the wind research cooperative at Oregon State University. The CD Stel sent us included hourly wind-speed data from various sites around the Northwest for the last 25 years. No one site had a complete history, so the first step in utilizing this data was auditing the information to find what periods and sites would give us the most useful results.

We found that there were five sites that had significant amounts of data. They are as follows:

1) **Browining Depot, MT:** Browning Depot is located in north central Montana at an elevation of 4500 feet and has been an active BPA monitoring site since October 1985.

2) **Cape Blanco, OR:** Cape Blanco is located along the southern Oregon coast near the town of Port Orford. Wind data has been collected at the site since October 1976. The Cape Blanco area sits on a coastal bench roughly 200 ft. above sea level and consists of rolling pasturelands bordered by trees.

3) **Goodnoe Hills, WA:** Goodnoe Hills is located east of the Columbia Hills region of southern Washington over looking the Columbia River Gorge. The site is located at an elevation of 2540 ft. The winds at the site are generally dictated by large-scale pressure differences between the Pacific and the interior of Oregon and Washington, and by the channeling effects of the Gorge.

4) **<u>Kennewick, WA</u>:** The Kennewick site is located in southern Washington near the town of Kennewick at an elevation of 2200 feet and has been monitored since 1976.

5) **<u>Seven Mile Hill, OR</u>:** Seven Mile Hill is located in north-central Oregon, west of The Dalles near the Columbia River Gorge. The site is situated along a ridge-line at an elevation of 1880 feet. Wind speeds have been monitored at this site since October 1978.

Once I found these sites, I sorted through and deleted all of the missing data. I was then able to find runs of data several months long that were useful for calculating average monthly capacity and average annual capacity. I was able to estimate generation using the following formula:

P = 0.5 x rho x A x Cp x V^3 x Ng x Nb

Where:

P = power in watts
rho = air density (about 1.225 kg/m^3 at sea level, less higher up)
A = rotor swept area exposed to the wind (m^2)
Cp = Coefficient of performance (0.59 maximum theoretically possible, 0.35 for a good design)
V = wind speed in meters/second (1 m/s = 2.24 mph)
Ng = generator efficiency
Nb = gearbox / bearings efficiency

The analysis was modeled using NEG Micon's NM72/2000 2 MW wind turbine, and the following assumptions were integrated into the study:

rho = 1
A = 4072 m^2
Cp = 0.35
Ng = 0.8
Nb = 0.9
Minimum Wind-Speed = 4 m/s
Maximum Capacity = 2 MW

In addition to the analysis done for the aforementioned sites, I also completed a study that examined the outcome if we had purchased a share of capacity from each of the five sites. The details of this test can be seen in charts numbered 6 and 12, and also in the tables below in the rows labeled "diversified mix".

Energy

After calculating the generation data, I was able to determine average monthly energy and I developed an 80% confidence interval for expected generation. This information is detailed in the attached graphs.

The attached graphs (labeled charts 1-6) detail monthly average energy by project site for every year in the study. The dash marks represent average energy for the month in a particular year. The table below provides annual average energy statistics and the periods of study for the different project sites that were analyzed:

Table #	Project Site	Period of Study	Annual Average Energy (aMW)	Annual Capacity Factor	Max	Min
1 & 7	Browning Depot	1994 – 2000	0.32	0.17	0.71	0.14
2 & 8	Cape Blanco, OR	1994 – 2000	0.51	0.26	0.73	0.32
3 & 9	Goodnow Hills, WA	1994 – 2000	0.29	0.15	0.38	0.24
4 & 10	Kennewick, WA	1995 – 2000	0.54	0.27	0.76	0.38
5 & 11	Seven Mile Hill, OR	1995 – 2000	0.33	0.17	0.61	0.11
6 & 12	Diversified Mix	1994 – 2000	0.39	0.23	0.51	0.31

As you can see, the best site (Kennewick) produced on average only 27% of its rated capacity. I was also able to find the amount of time that it would be impossible to generate using wind turbines at these sites.

Project Site	% Time With No Generation
Browning Depot	31.0
Cape Blanco, OR	23.0
Goodnow Hills, WA	31.0
Kennewick, WA	25.0
Seven Mile Hill, OR	35.0
Diversified Mix	0.6

The best site, Cape Blanco in this case, still was not able to generate any energy 23% of the time due only to low wind speeds. The “Diversified Mix” scenario was calculated by finding the amount of time that none of the five sites were generating. Forced outages, planned maintenance, and icing conditions are not considered in these percentages.

Capacity

The attached graphs (labeled charts 7-12) detail monthly average energy and provide 80% confidence intervals* for average generation. The intervals show us, with 80% certainty, how much generation we can expect at these different sites. Please note that in reality the minimum generation possible is zero MW and the maximum possible generation with the assumed turbine is 2 MW, however for illustrative purposes these limitations were not enforced. The connected dash marks on the graphs represent the confidence interval limits, and the solid line in the middle represents average monthly energy for the previously specified periods of study.

The charts show that during every month at every site there is a significant chance that actual average energy will be close to zero aMW. This indicates that adding wind to our system could bring along with it more variability in our generation portfolio and it could provide many challenges to effectively integrate it into our system. In short, we cannot count on wind for system capacity.

* At the 80% confidence level, wind resources cannot be relied upon for system capacity.

ASSUMPTIONS

1) The formula for converting the wind speed from m/s into generation in watts is as follows:

P=0.5*rho*A*Cp*(V^3)*Ng*Nb where:

P = power in watts
rho = air density (about 1.225 kg/m^3 at sea level, less higher up)
A = rotor swept area, exposed to the wind (m^2)
Cp = Coefficient of performance (.59 is the maximum performance theoretically possible, .35 for a good design)
V = Wind speed in m/s
Ng = generator efficiency
Nb = gearbox/bearings efficiency (could be as high as 95% for a great design)

2) Assumptions used in calculating theoretical generation where actual data was not available are as follows:

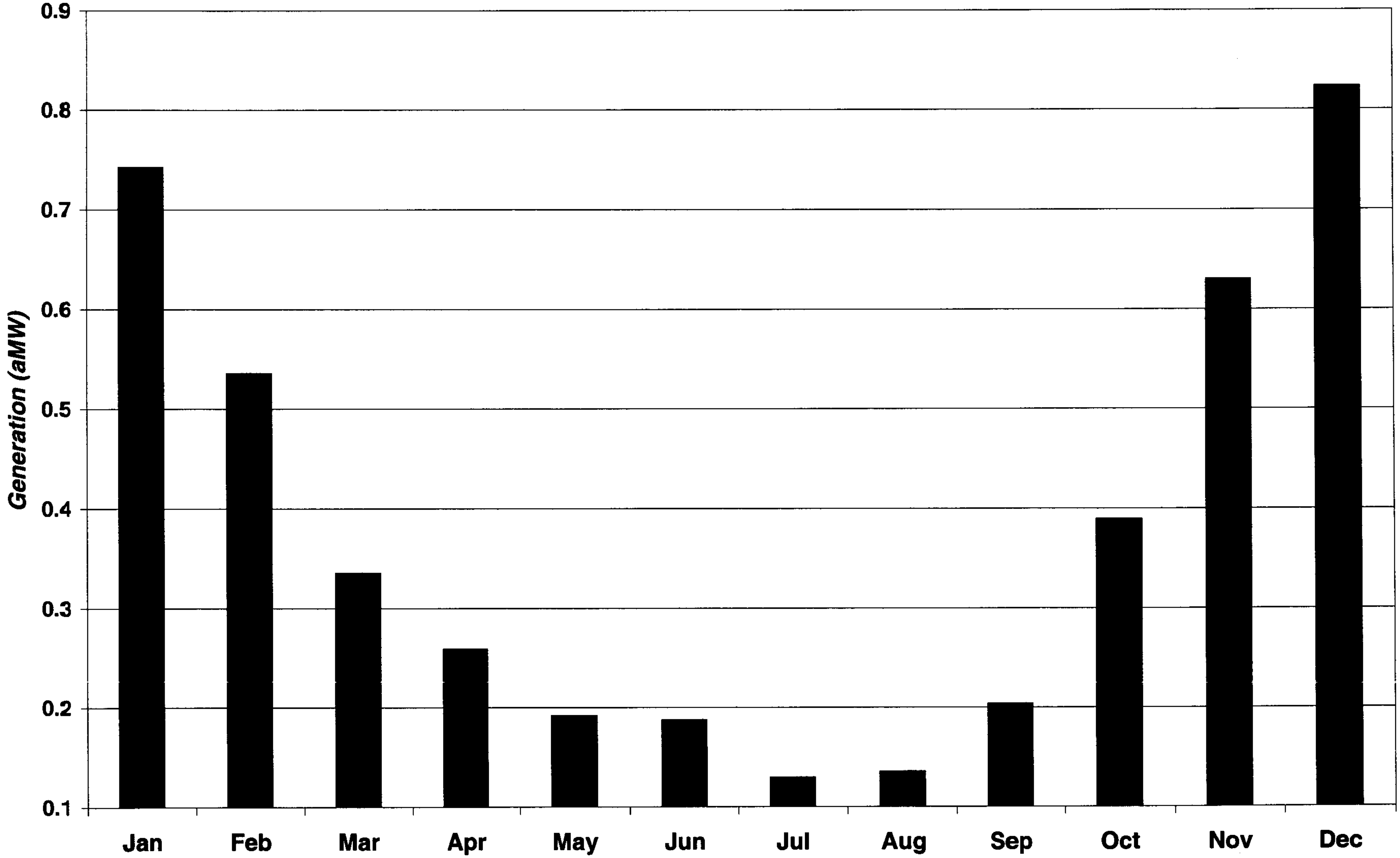
a) air density = 1 kg/m^3
b) Cp = .35
c) Ng = .8
d) Nb = .9

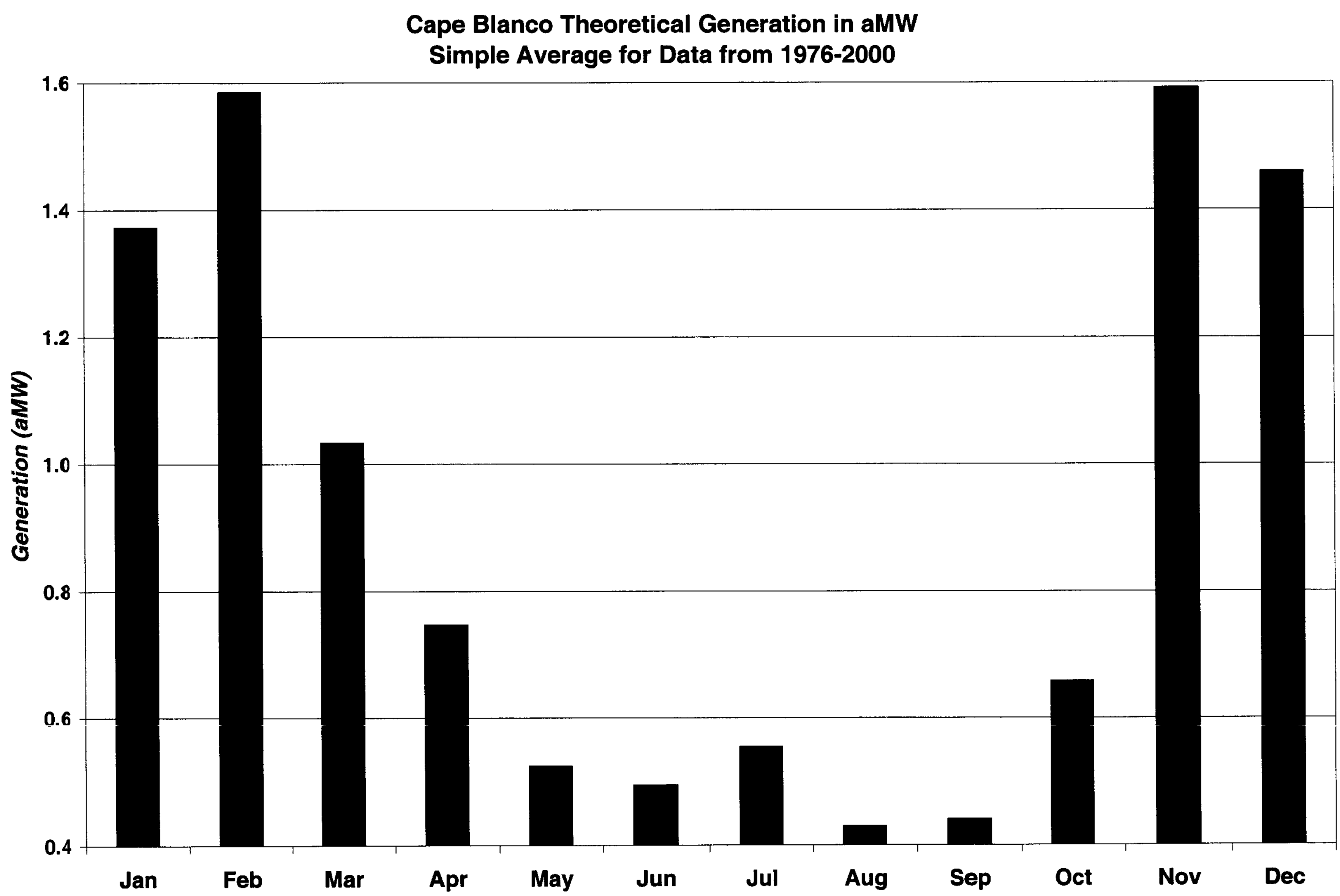
3) Wind generation data modelled after use with NEG Micon's 2 MW Active-Stall wind turbine, model name NM72/2000.

a) A = 4072 m^2 with this design
b) Other model specifications available upon request.

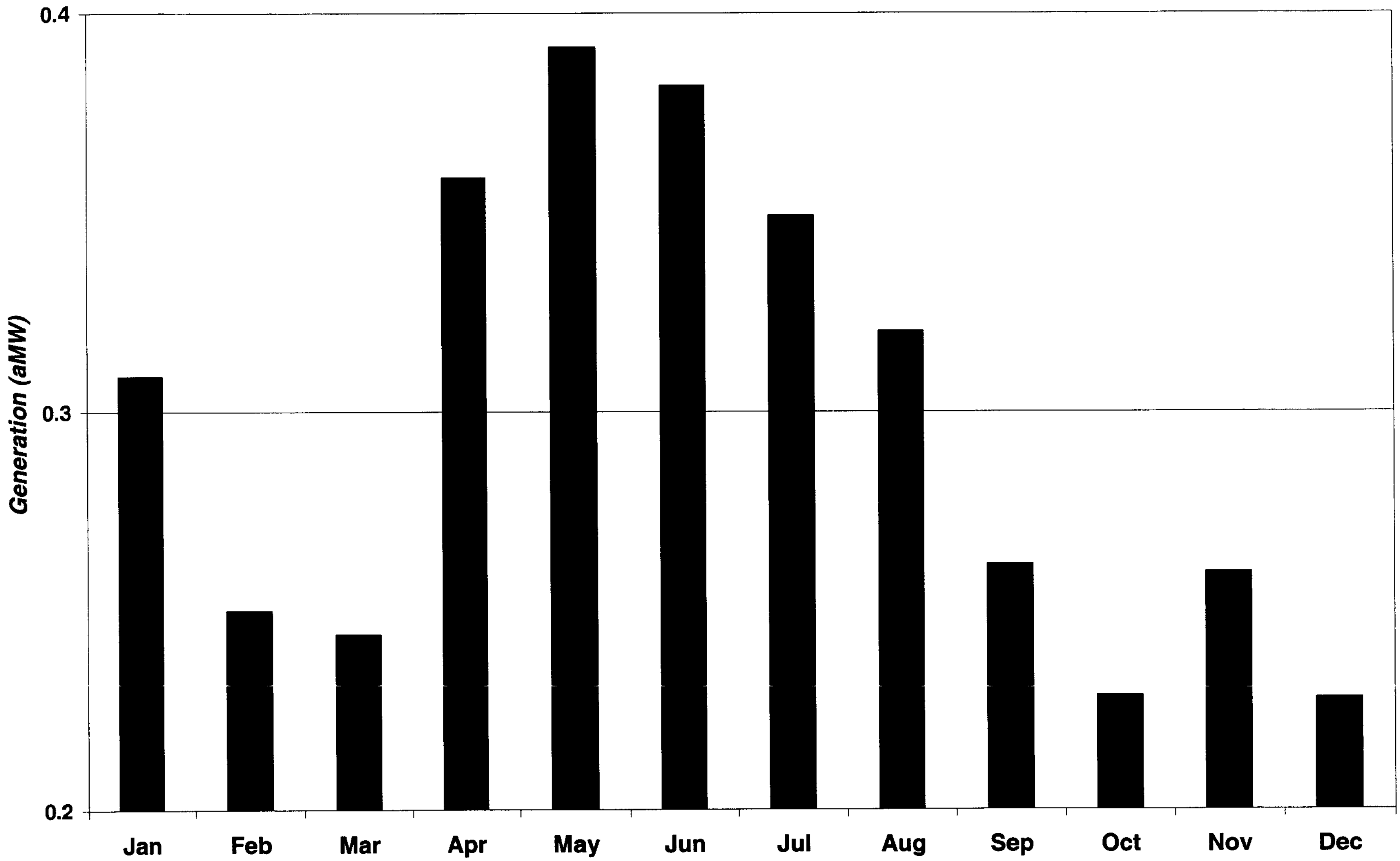
4) The turbine's 2 MW capacity is not reflected in the generation numbers, meaning that some gen figures are higher than 2 which would not happen with actual generation.

Browning Depot Theoretical Generation in aMW
Simple Average for Data from 1985-2000

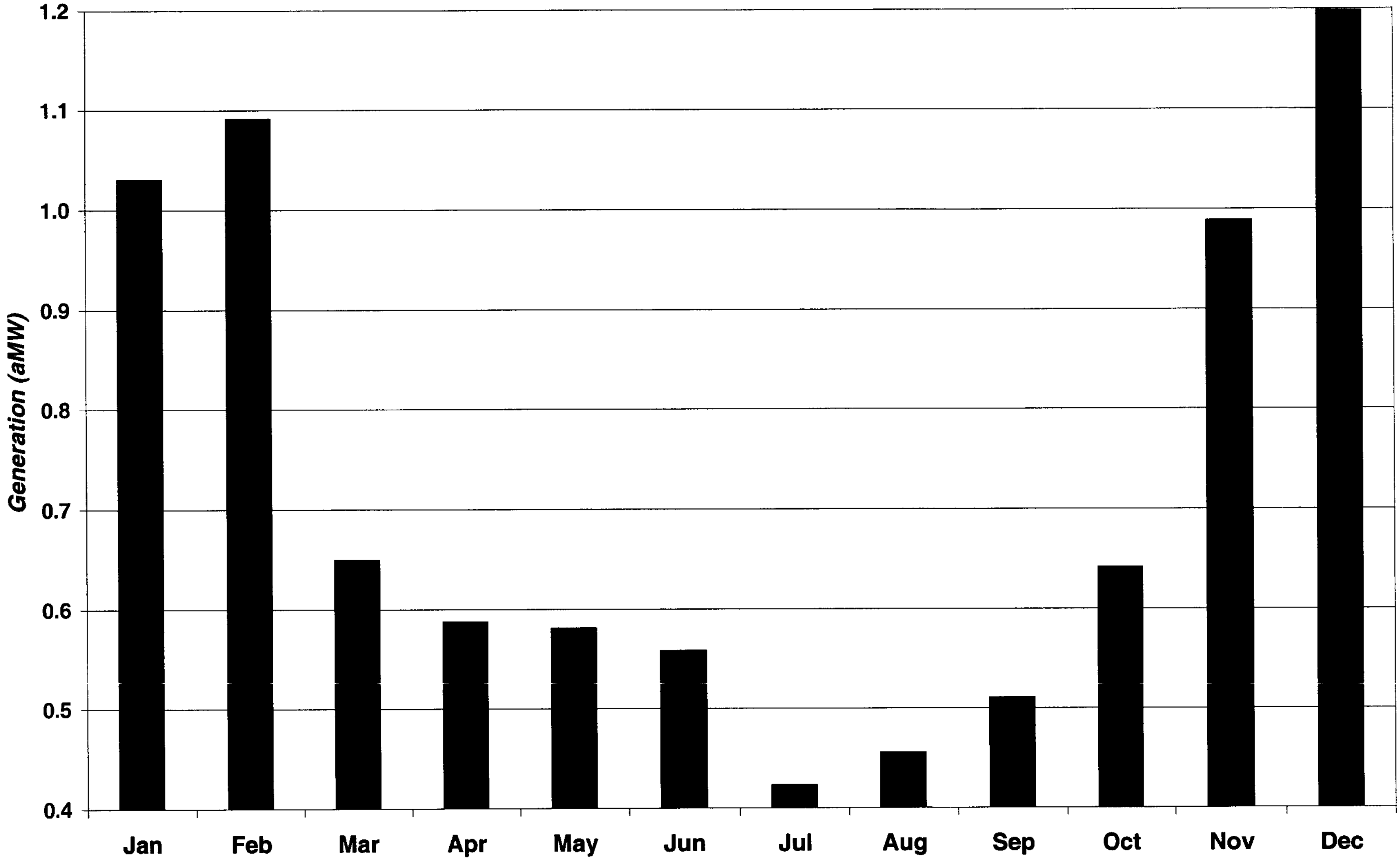



Cape Blanco Theoretical Generation in aMW
Simple Average for Data from 1976-2000
Generation (aMW)
1.6
1.4
1.2
1.0
0.8
0.6
0.4
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec

Goodnoe Hills Tower Theoretical Generation in aMW
Simple Average for Data from 1980-2000



Kennewick Theoretical Generation in aMW
Simple Average for Data from 1987-2000



Seven Mile Hill Theoretical Generation in aMW
Simple Average for Data from 1978-2000

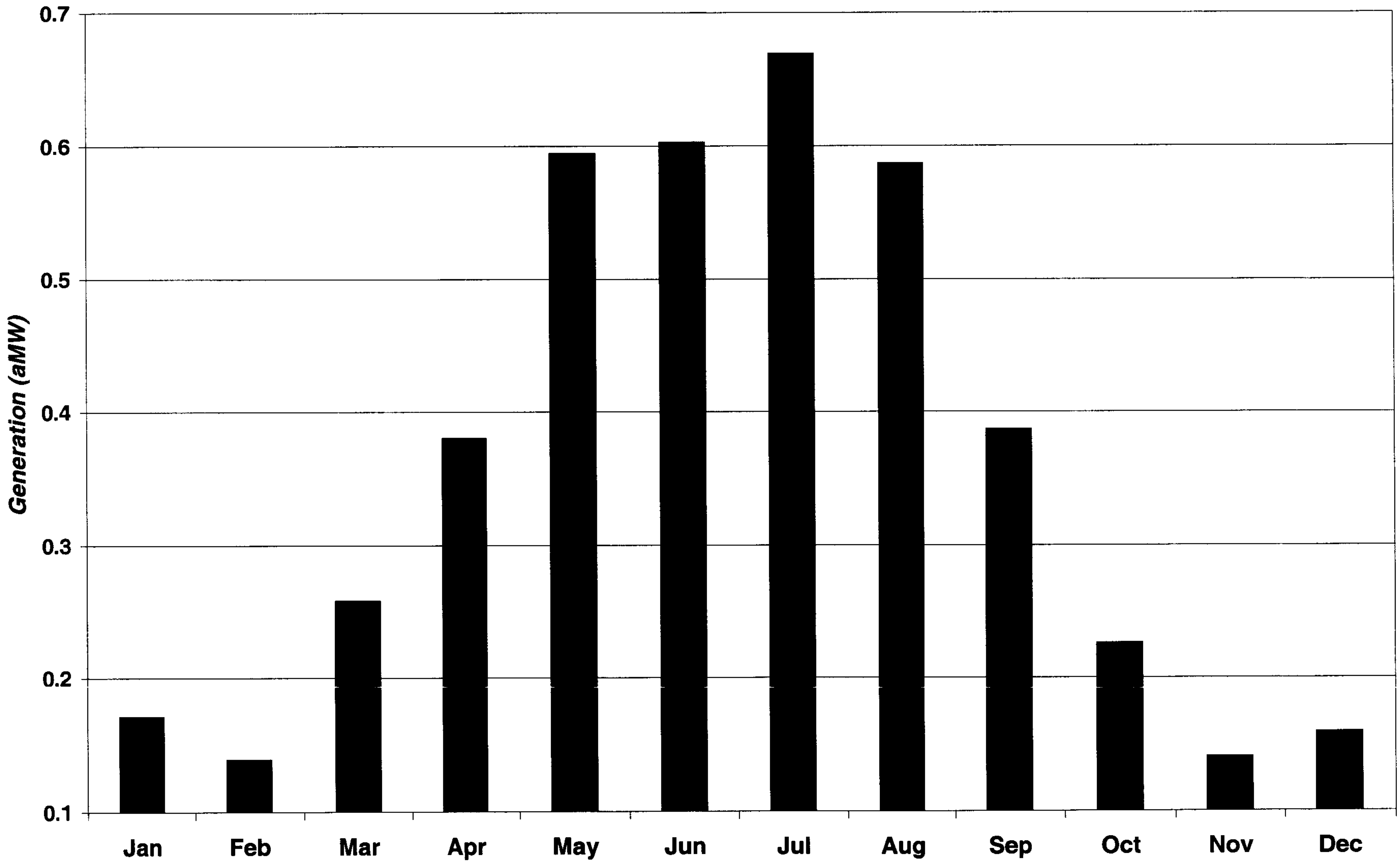


Chart 6
Diversified Portfolio
Average Theoretical Wind Generation by Month (based on 1 MW installation)

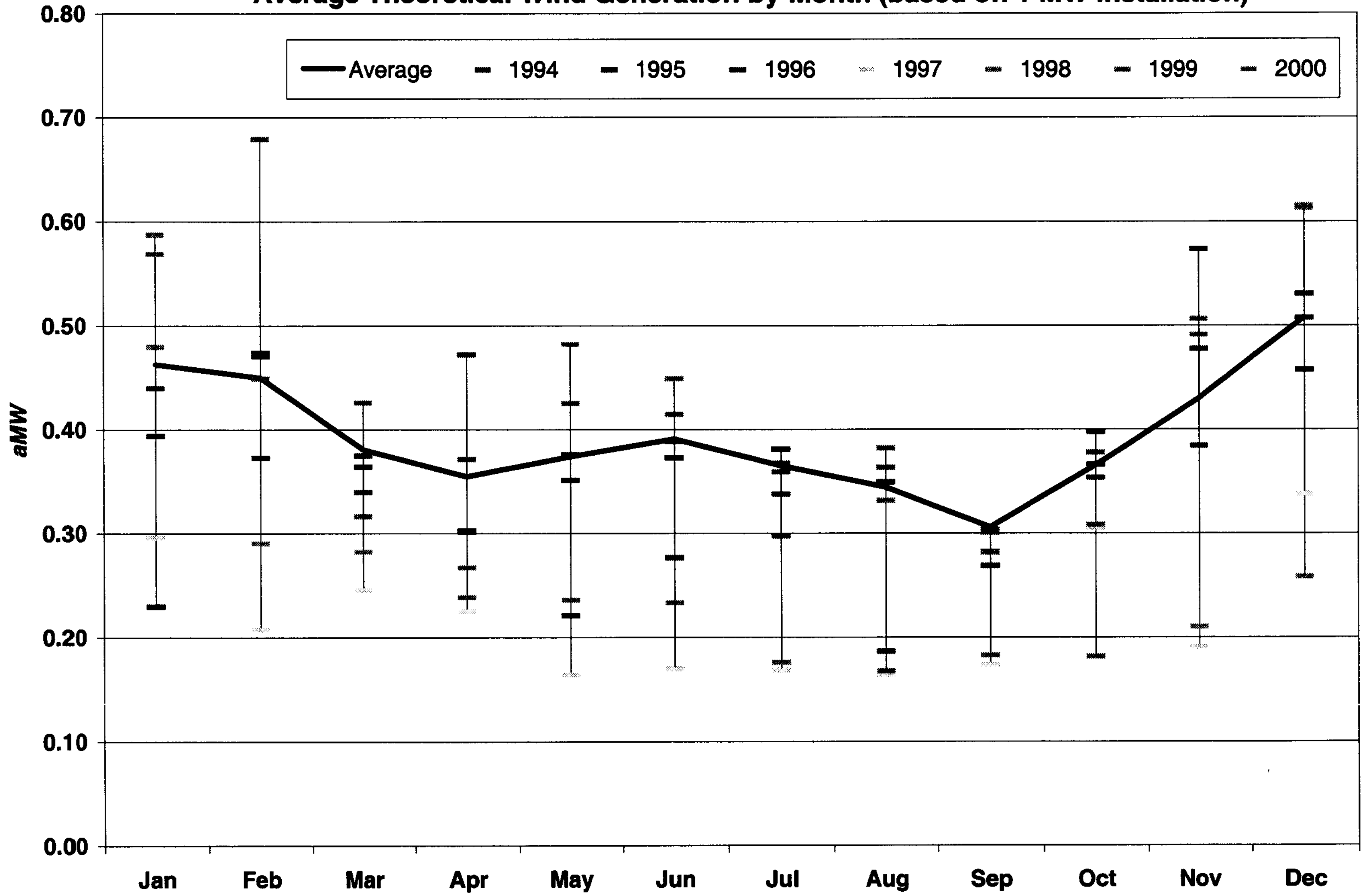
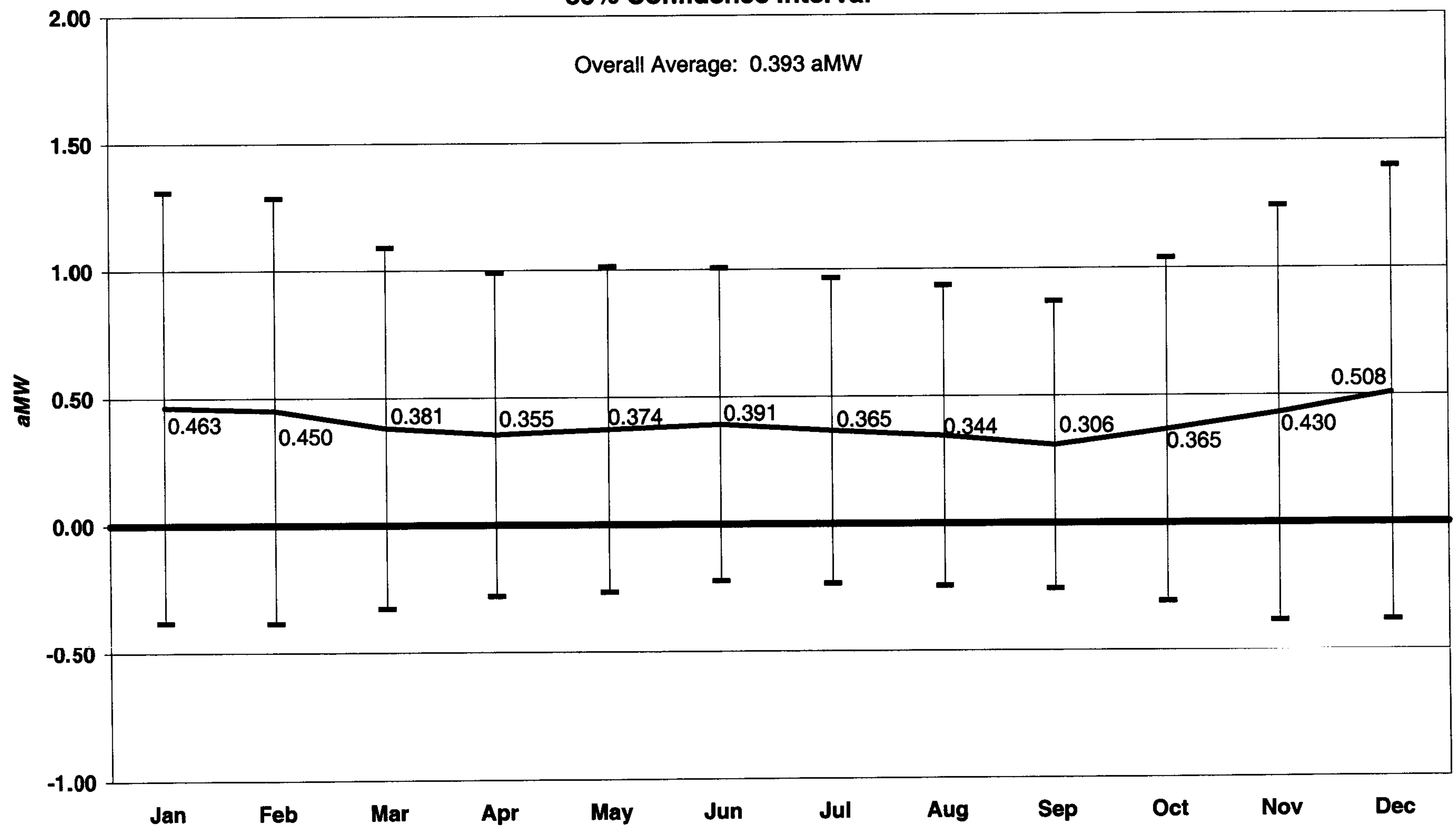
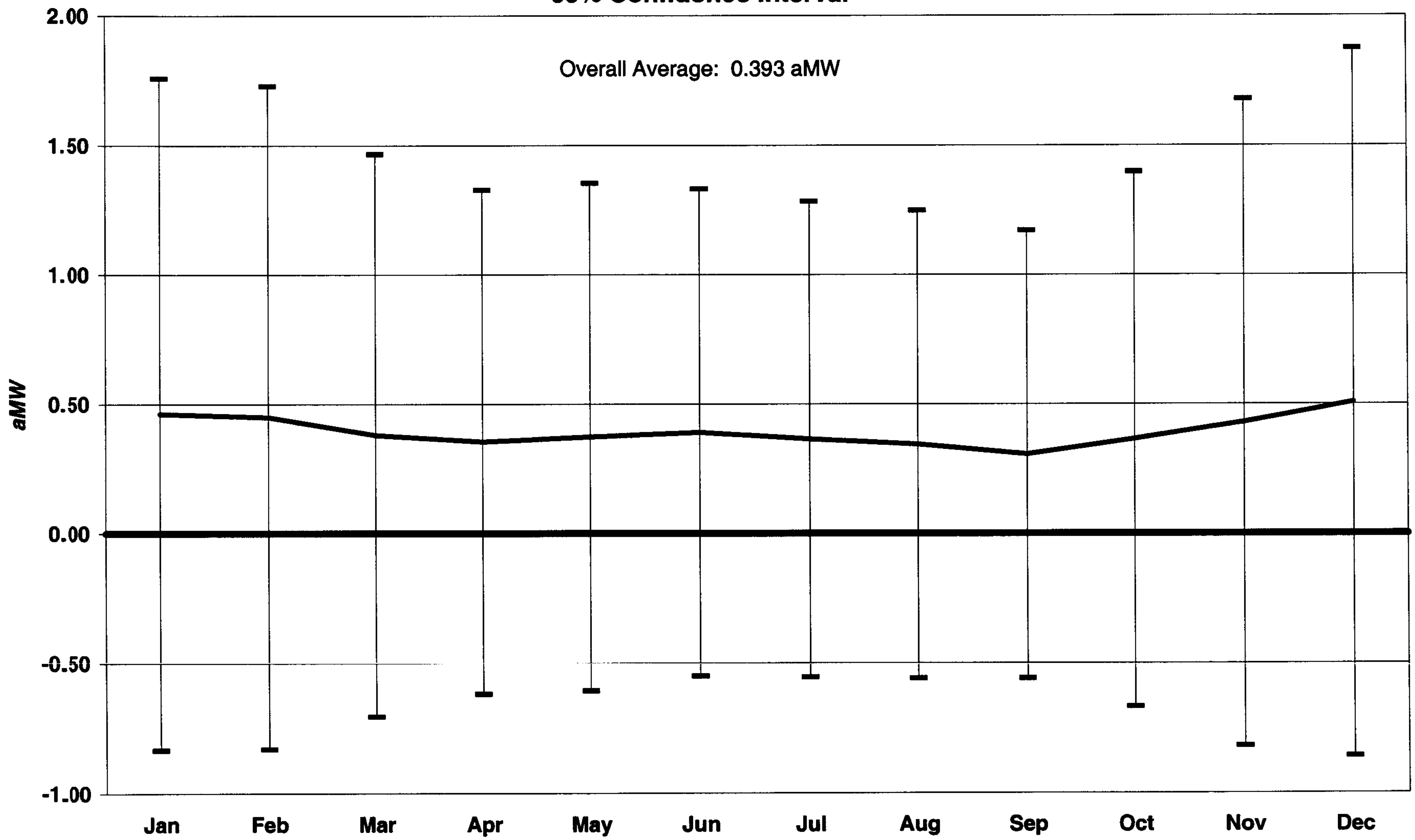


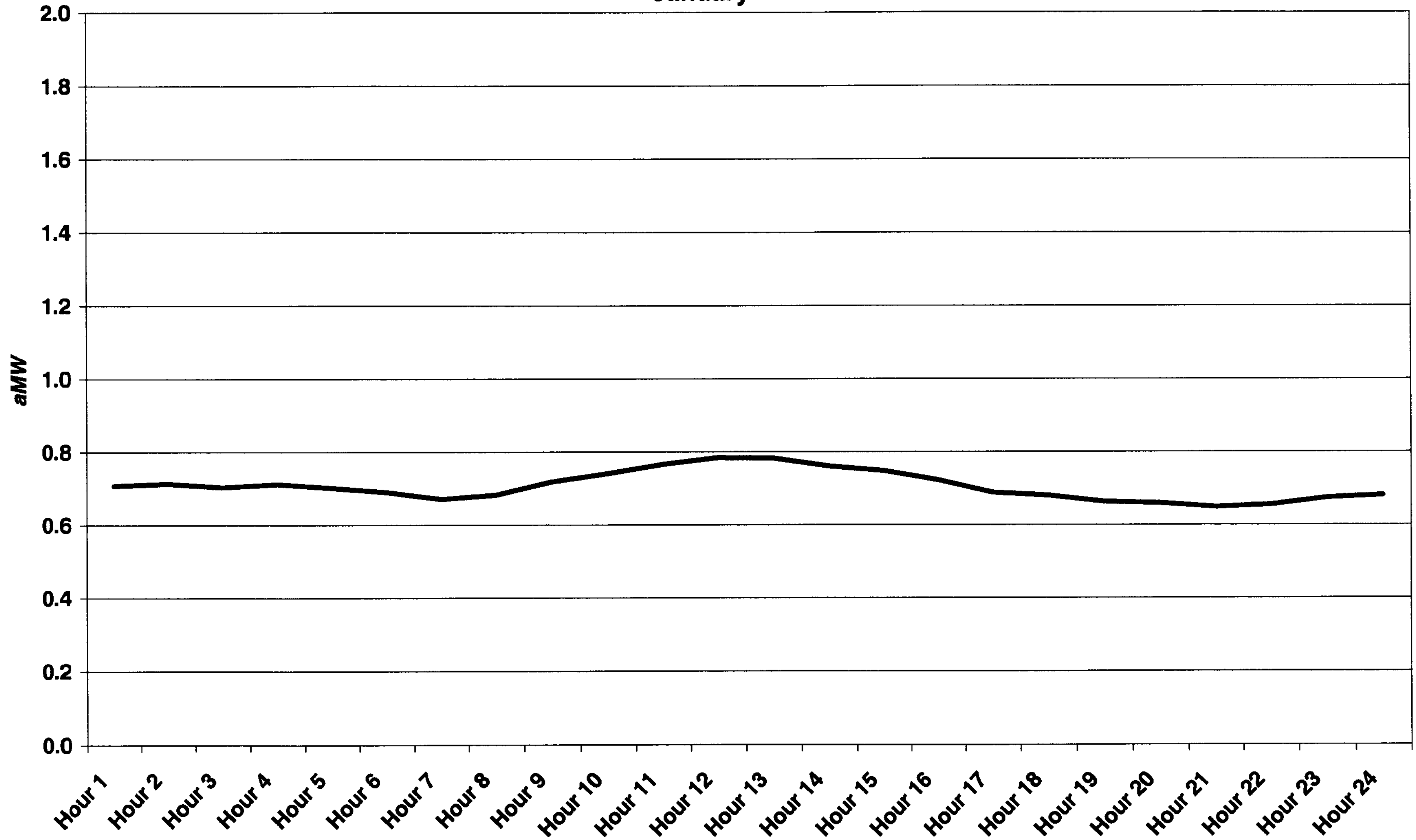
Chart 12
Diversified Portfolio
Average Theoretical Generation by Month
80% Confidence Interval



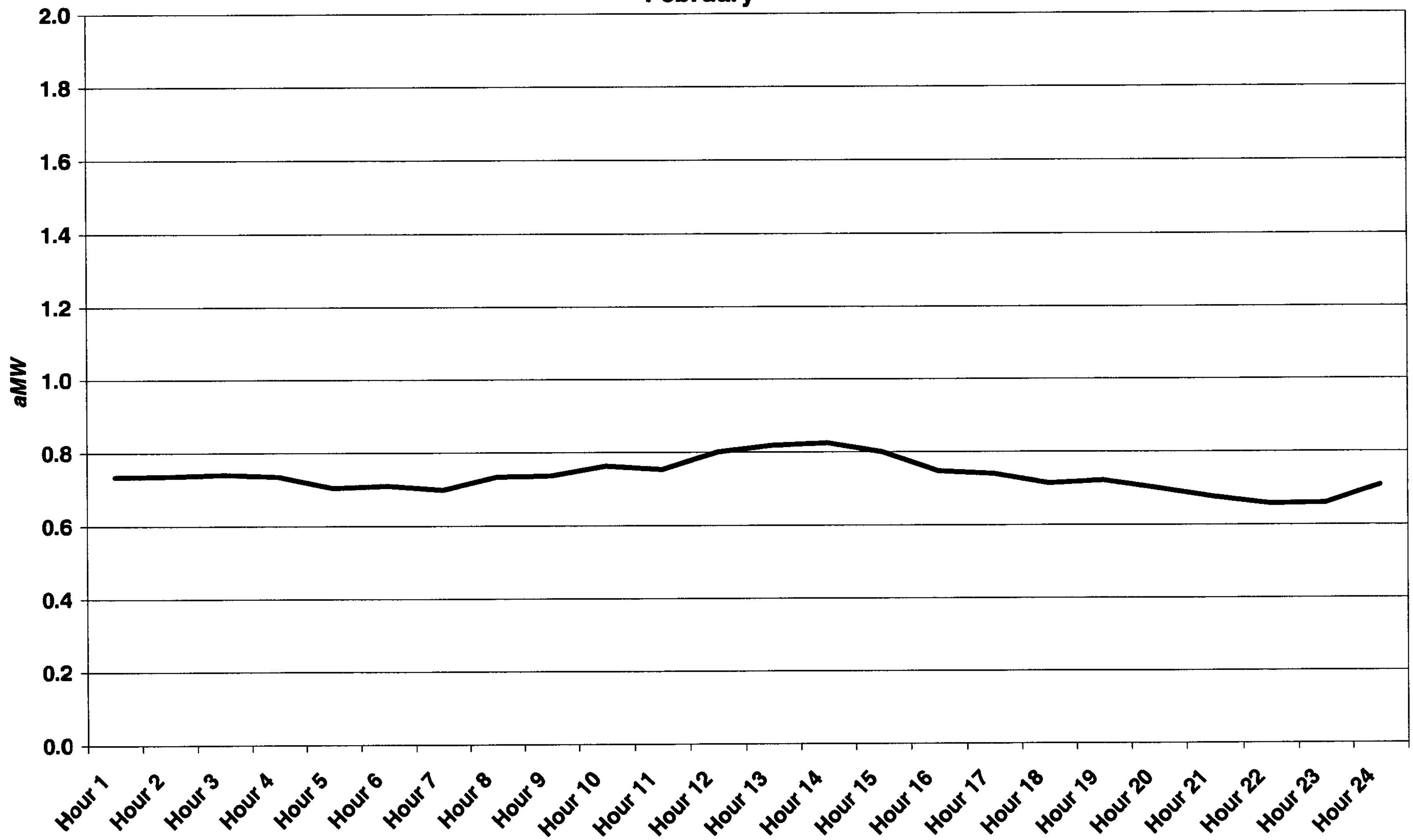
Diversified Portfolio
Average Theoretical Generation by Month
95% Confidence Interval



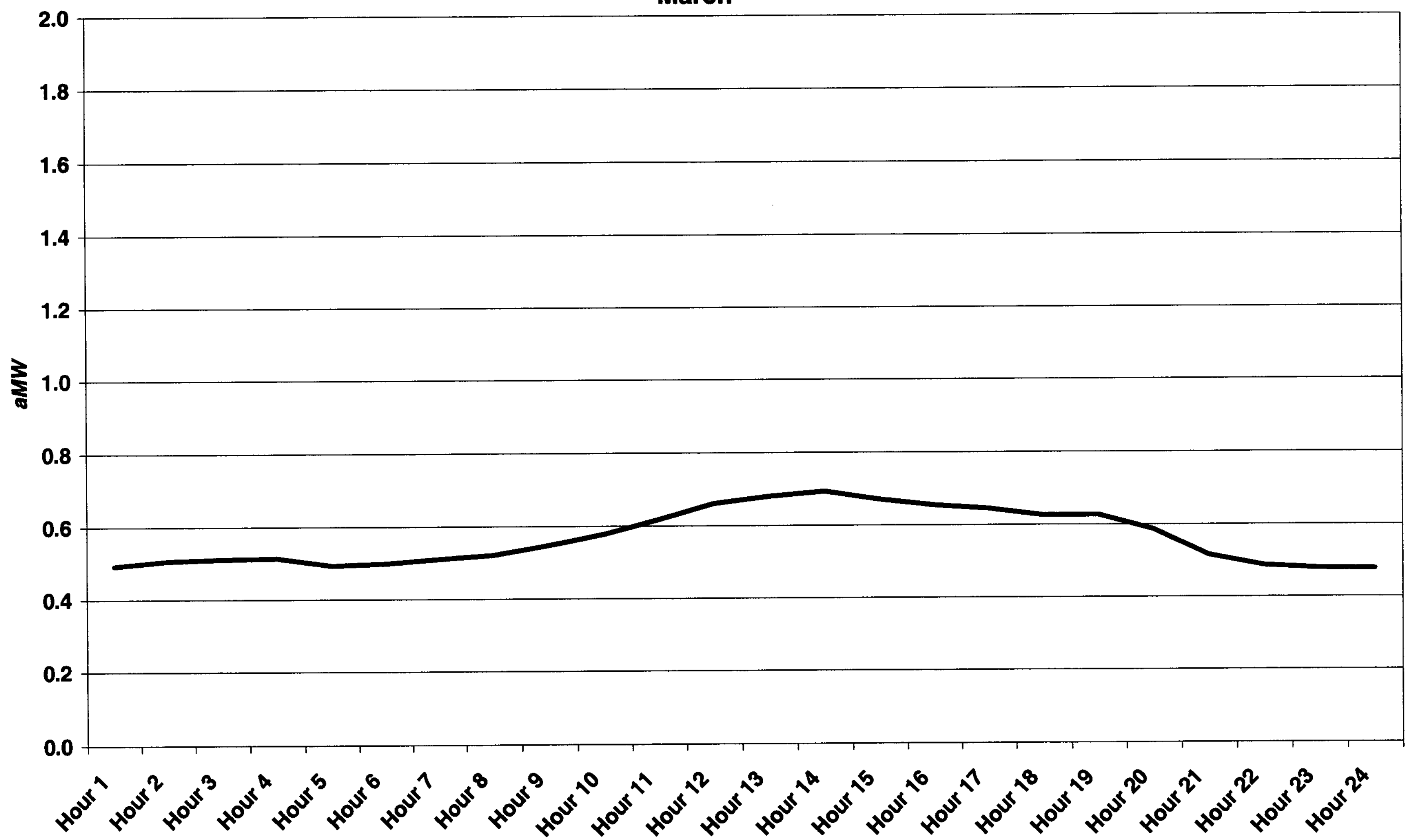
Cape Blanco, OR
Average Hourly Theoretical Generation
January



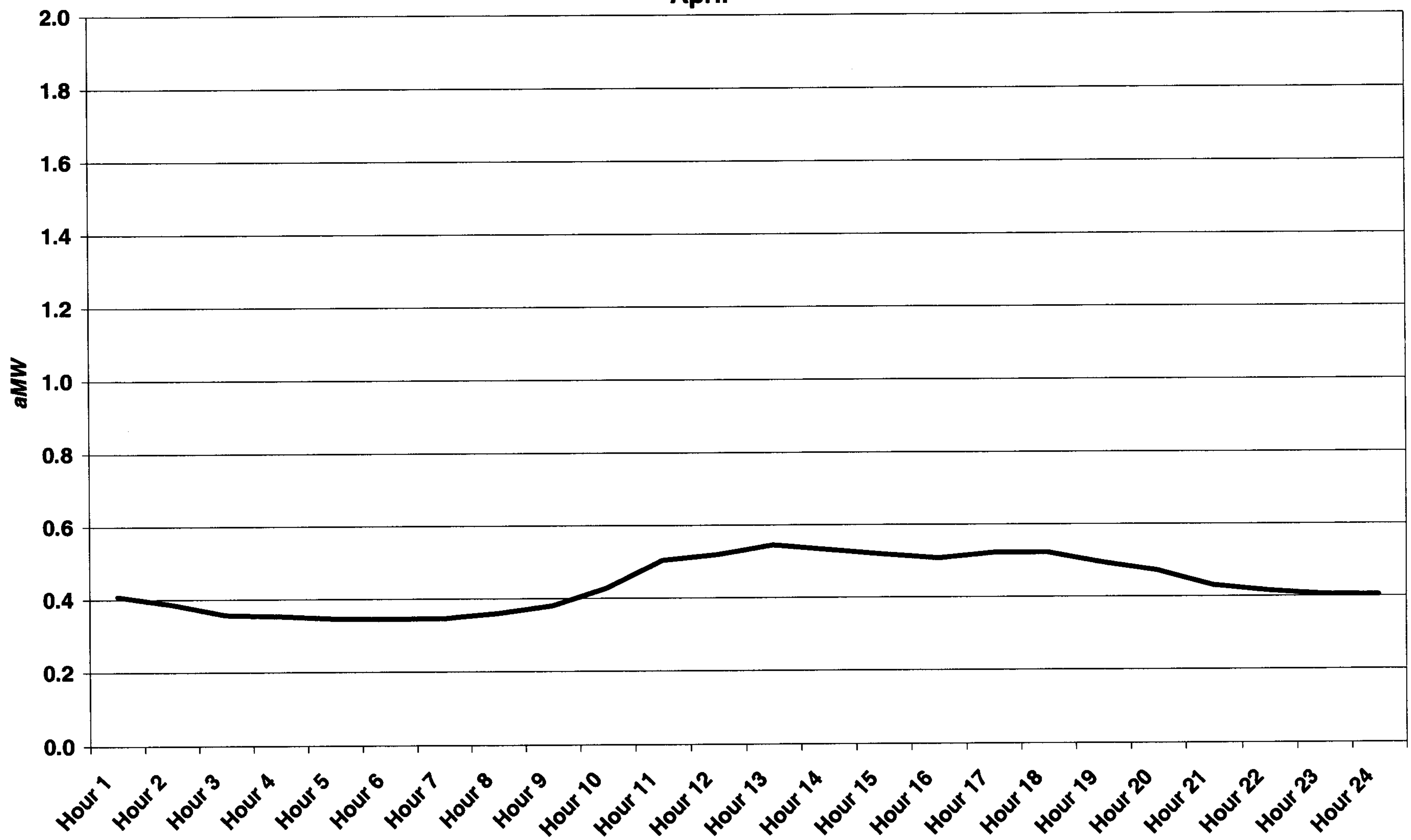
Cape Blanco, OR
Average Hourly Theoretical Generation
February

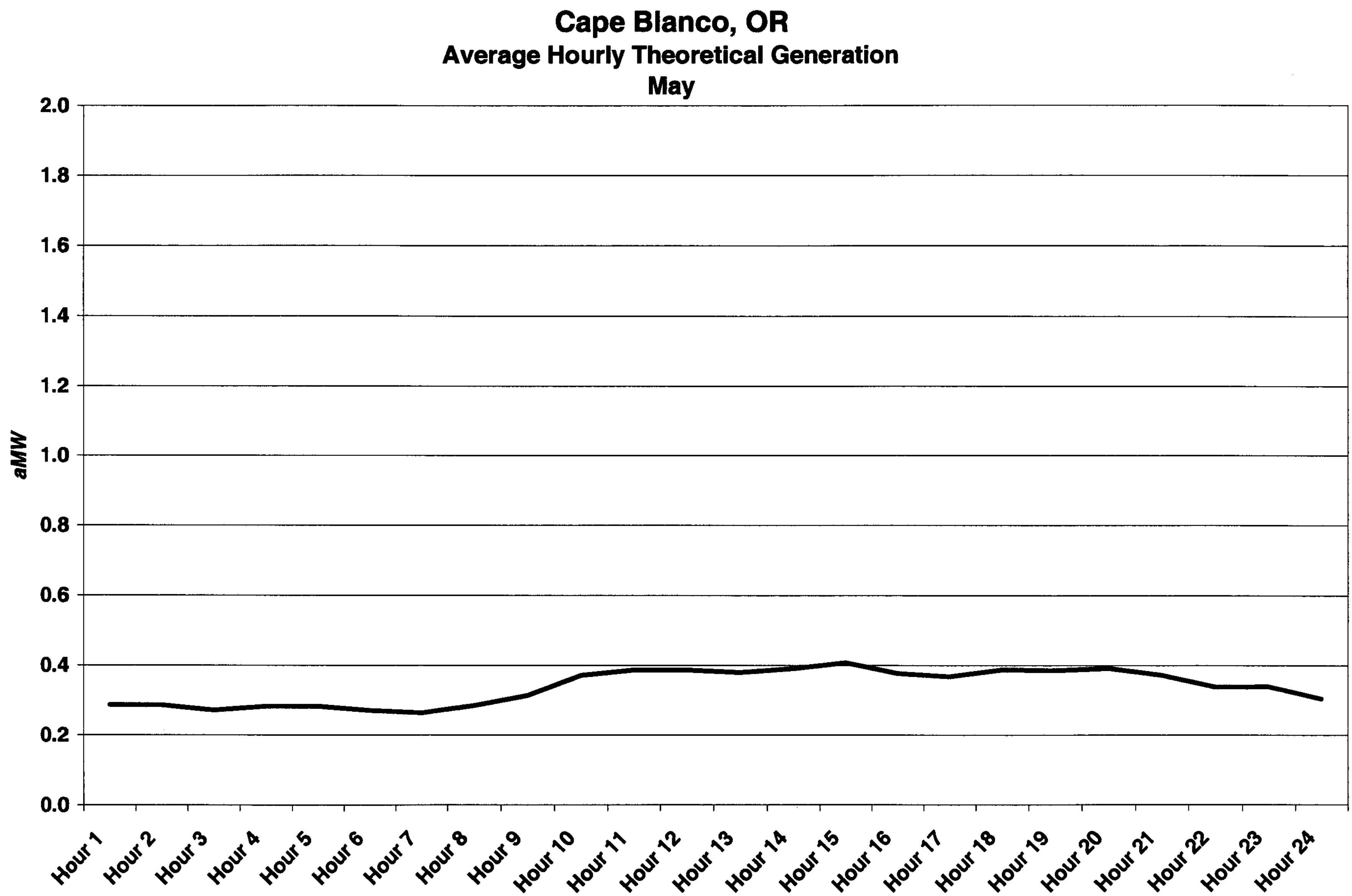


Cape Blanco, OR
Average Hourly Theoretical Generation
March



Cape Blanco, OR
Average Hourly Theoretical Generation
April





Cape Blanco, OR
Average Hourly Theoretical Generation
May
aMW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
Hour 1
Hour 2
Hour 3
Hour 4
Hour 5
Hour 6
Hour 7
Hour 8
Hour 9
Hour 10
Hour 11
Hour 12
Hour 13
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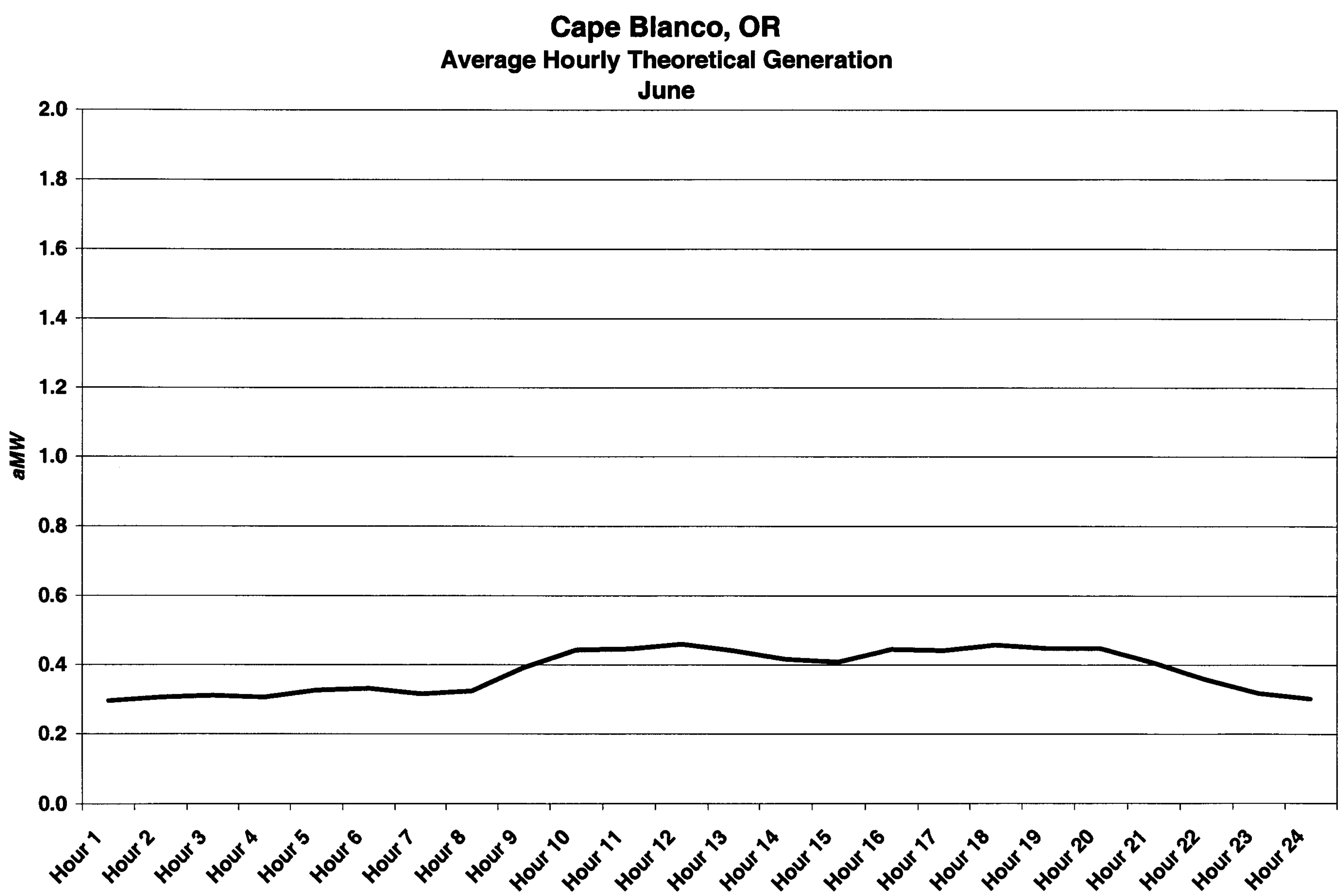
Hour 22
Hour 23
Hour 24



Cape Blanco, OR
Average Hourly Theoretical Generation
June
aMW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
Hour 1
Hour 2
Hour 3
Hour 4
Hour 5
Hour 6
Hour 7
Hour 8
Hour 9
Hour 10
Hour 11
Hour 12
Hour 13
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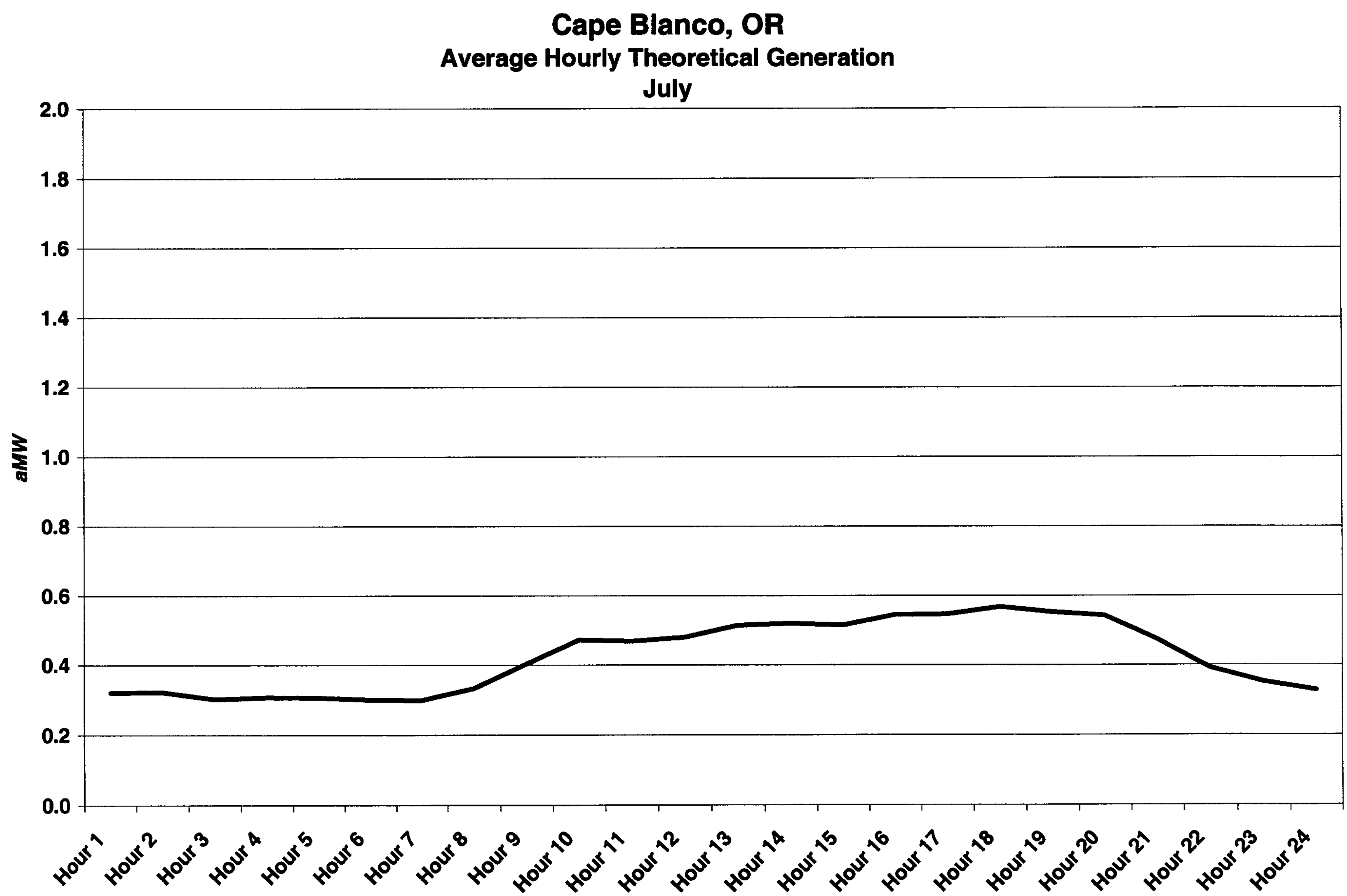
Hour 22
Hour 23
Hour 24


Cape Blanco, OR
Average Hourly Theoretical Generation
July
aMW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
Hour 1
Hour 2
Hour 3
Hour 4
Hour 5
Hour 6
Hour 7
Hour 8
Hour 9
Hour 10
Hour 11
Hour 12
Hour 13
Hour 14
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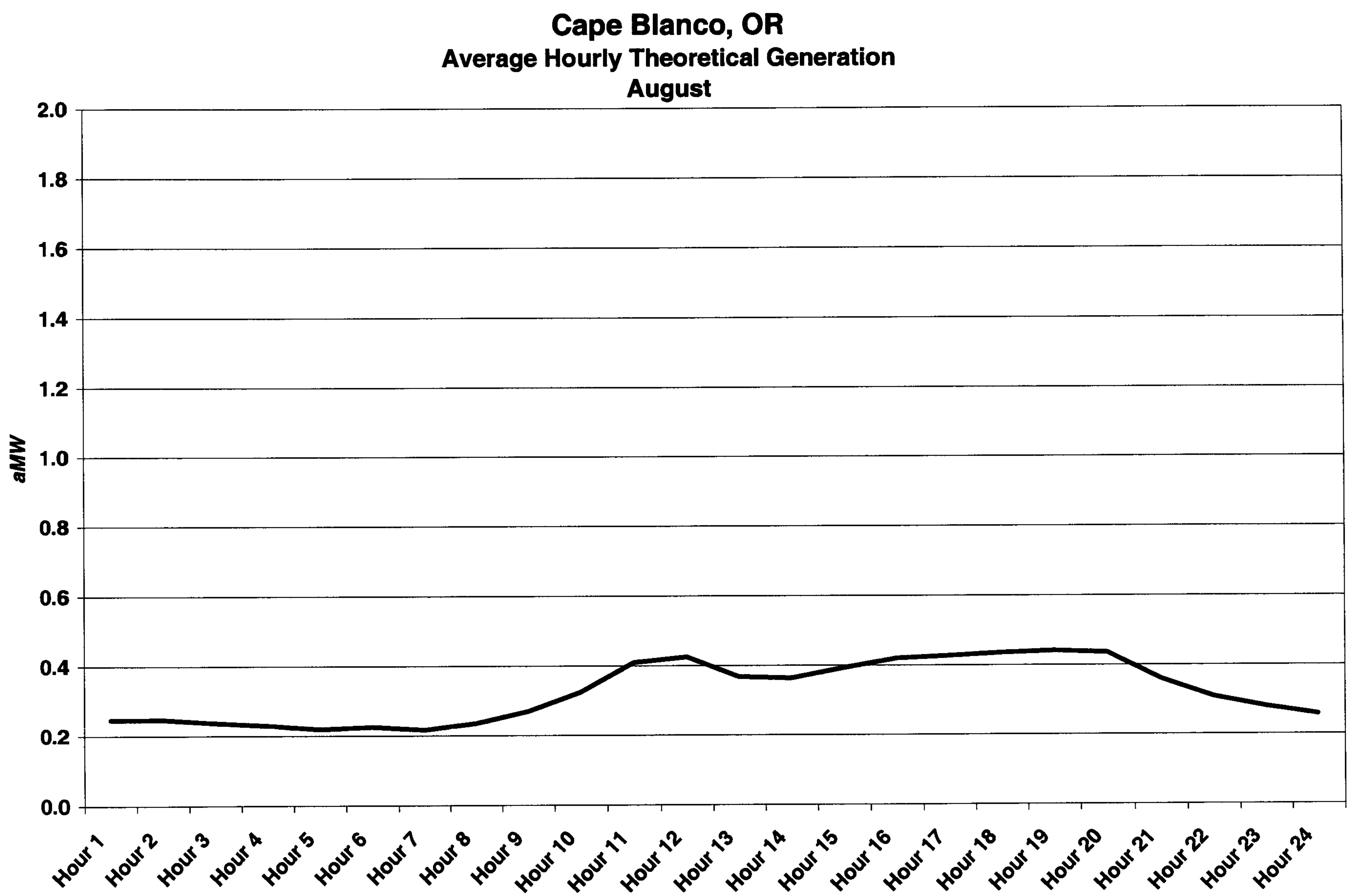
Hour 22
Hour 23
Hour 24


Cape Blanco, OR
Average Hourly Theoretical Generation
August
aMW
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
Hour 1
Hour 2
Hour 3
Hour 4
Hour 5
Hour 6
Hour 7
Hour 8
Hour 9
Hour 10
Hour 11
Hour 12
Hour 13
Hour 14
Hour 15
Hour 16
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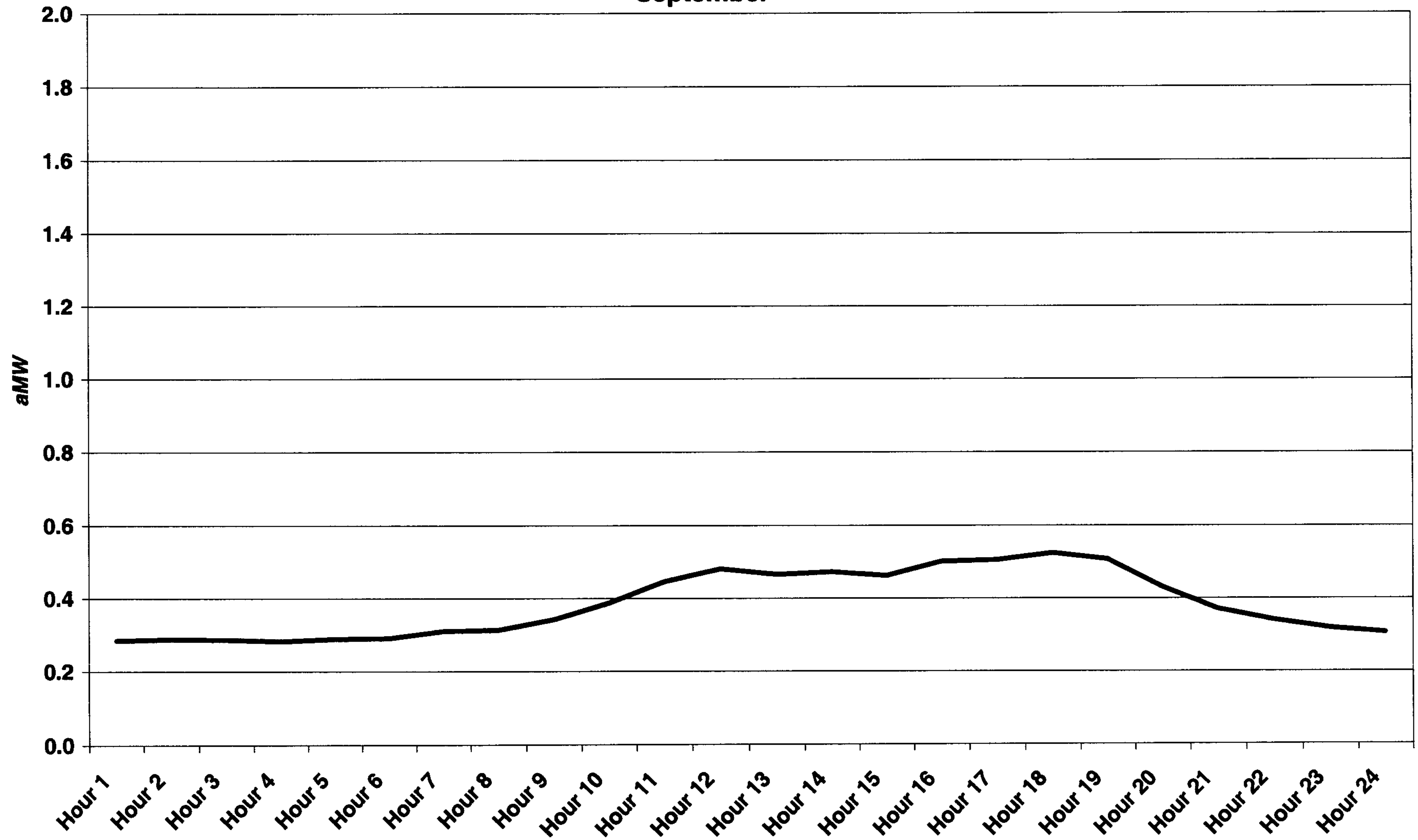
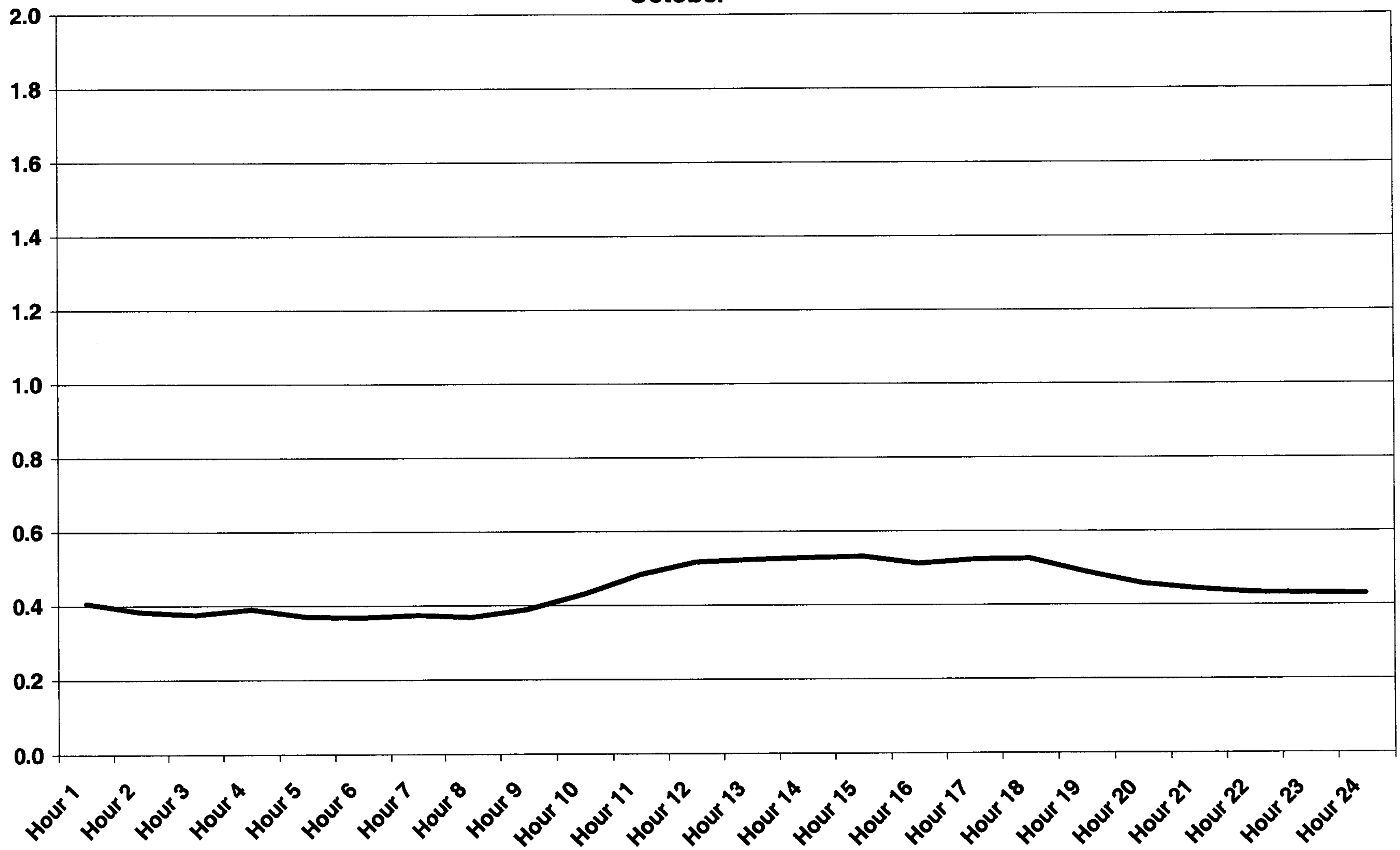
Hour 18
Hour 19
Hour 20
Hour 21
Hour 22
Hour 23
Hour 24

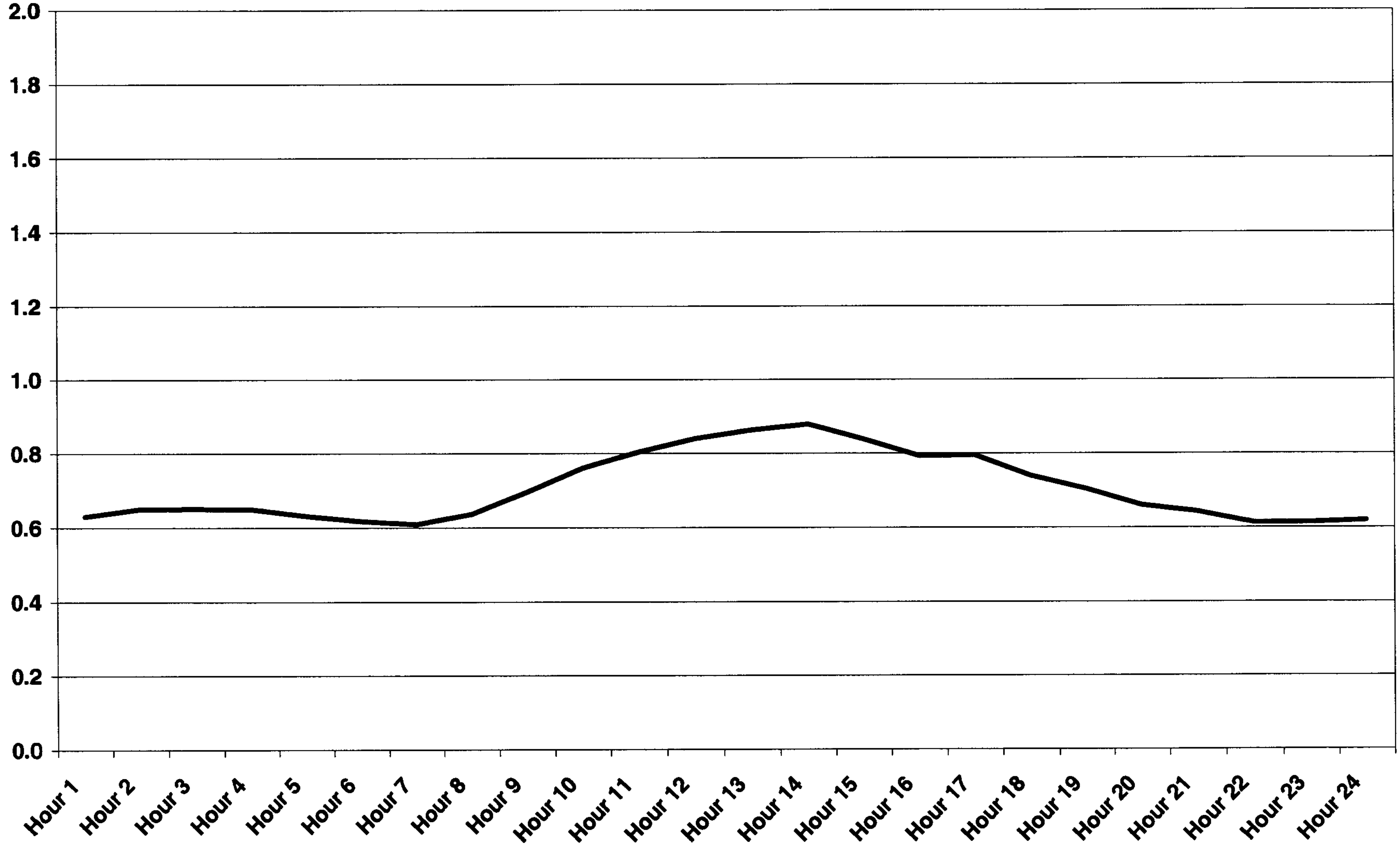
Cape Blanco, OR
Average Hourly Theoretical Generation
September



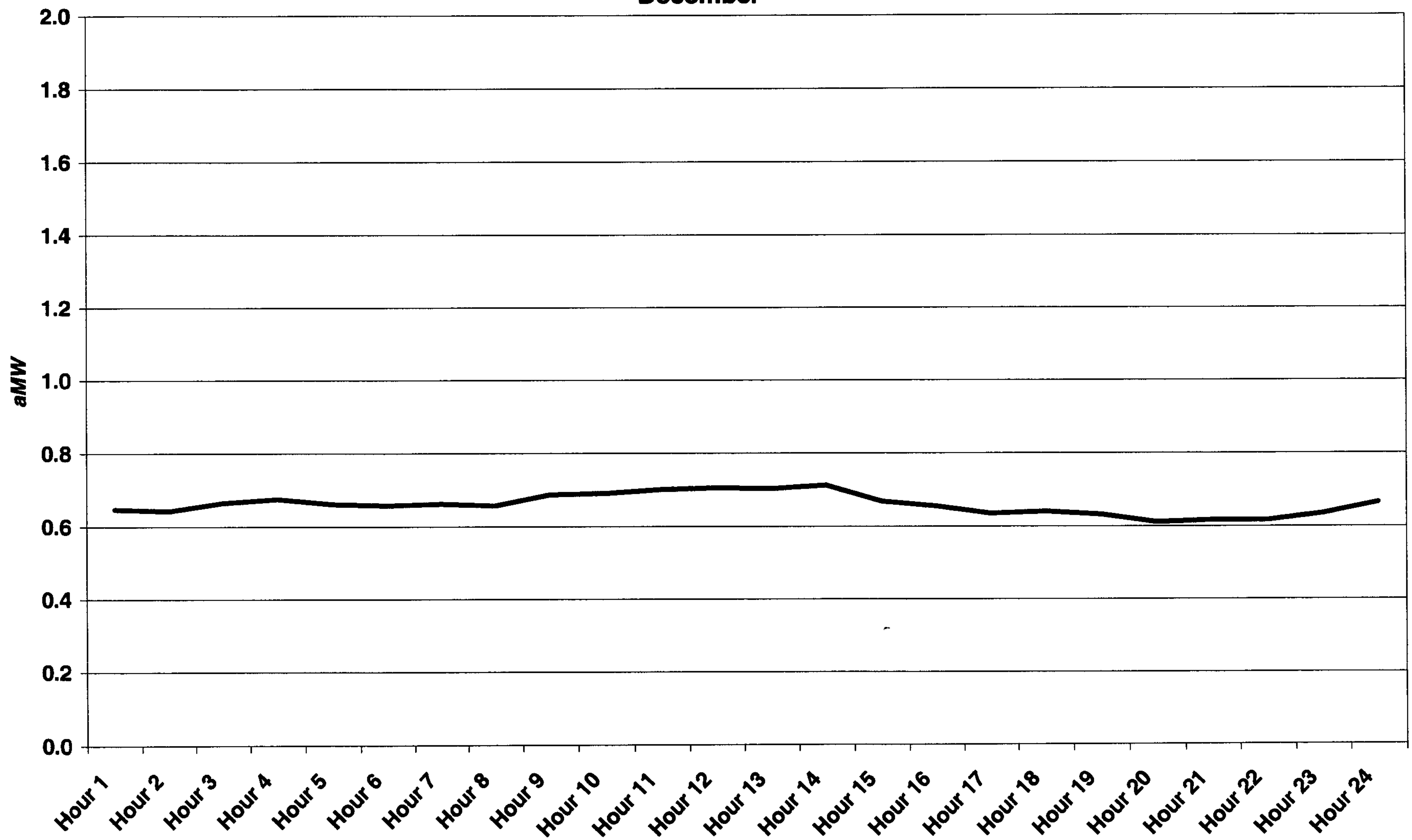
Cape Blanco, OR
Average Hourly Theoretical Generation
October



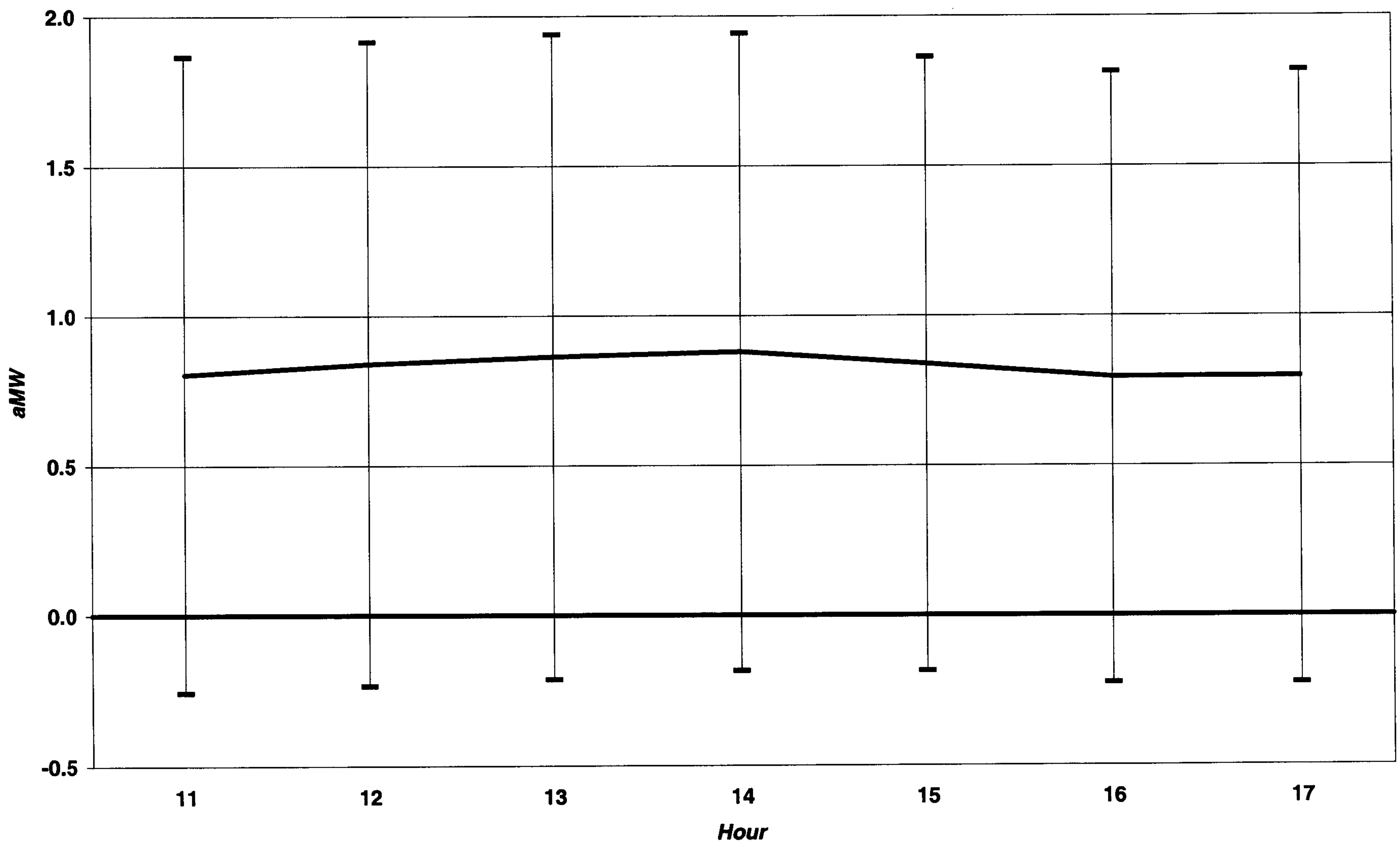
Cape Blanco, OR
Average Hourly Theoretical Generation
November



Cape Blanco, OR
Average Hourly Theoretical Generation
December



Cape Blanco, OR



AVISTA Utilities

Interoffice Memorandum
Energy Resources

DATE: April 4, 2002

TO: Clint Kalich

FROM: Brad Simcox

SUBJECT: Wind Analysis Update

Clint-

Stel Walker, director of the wind research cooperative at OSU, had recently been in contact with us regarding my wind energy analysis. While he approved of most of our methods and results, he did make a couple of suggestions to improve the outcome of the study. Because of this, I went through and made some changes to the study.

First, Stel thought that we should use a smaller 660 kW turbine to model the resource rather than the 2 MW machine that we had used in the initial study. This would give us less time with zero generation (since this turbine can operate at lower wind speeds) and a higher annual capacity factor. Second, he asked me to take into consideration that the sensors used to gather wind speed data and the height of the actual turbine are different; typically, the turbine would be constructed at a higher altitude than the sensors were placed at, so he gave me a formula to adjust for this difference. I used this factor for every site except Cape Blanco, OR, which is a coastal site and according to Stel would have the highest wind speeds at the height that the sensor was placed. For most sites, this added an extra 10% or so to the calculated generation. Lastly, Stel made me aware that wind turbines “cut-out” when the wind speed exceeds a certain point in order to avoid damage to the rotor. For both the 2MW and 660 kW turbines, this wind speed is 25 m/s (or 56 mph). I made all of these adjustments to both the study using the 2 MW turbine and the one with the 660 kW turbine.

After looking at the results, it is apparent that the 660 kW turbine does improve our annual capacity factor and our decreases our time without any generation. However, none of these improvements warrant any excitement – the numbers still look fairly poor. I have attached summaries by site that outline average monthly generation, average annual generation, annual capacity factor, and time with zero generation. Please let me know if you would like any additional detail provided or analysis performed regarding this information.

Thanks.
Brad Simcox
Energy Resources Intern

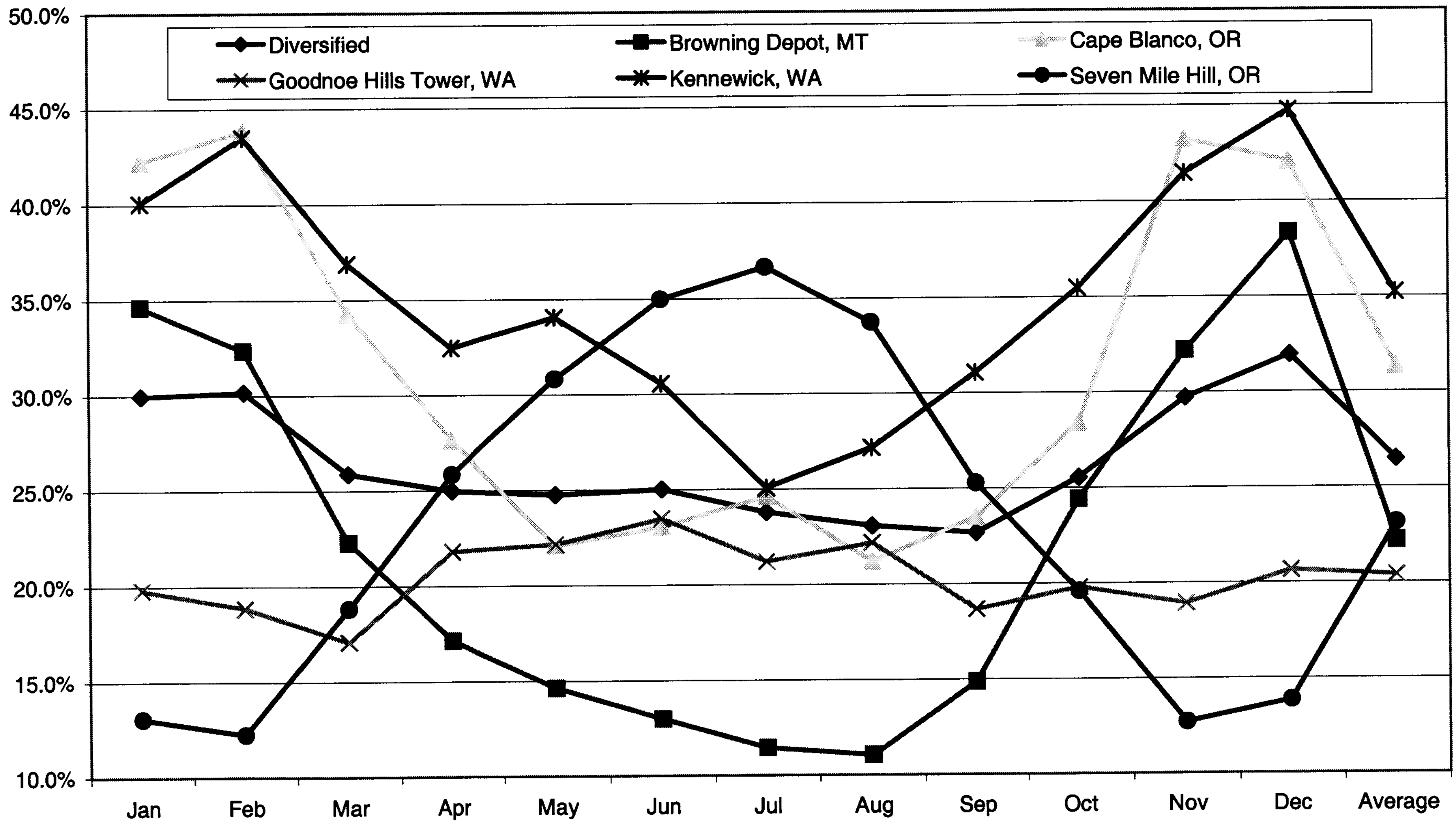
Wind Power Statistics
1994-2000 Capacity Factor Summary by Year

Year	Diversified	Browning Depot, MT	Cape Blanco, OR	Goodnoe Hills Tower, WA	Kennewick, WA	Seven Mile Hill, OR
2000	25.2%	24.3%	29.3%	21.1%	NA	25.9%
1999	28.2%	23.6%	33.6%	19.6%	39.9%	24.1%
1998	25.6%	18.8%	NA	NA	34.0%	24.0%
1997	27.6%	23.8%	30.4%	NA	35.2%	21.2%
1996	26.9%	24.6%	32.5%	20.2%	35.7%	21.5%
1995	25.8%	21.7%	31.2%	20.0%	35.4%	20.9%
1994	NA	18.6%	29.6%	19.6%	33.5%	24.3%
Average	26.5%	22.2%	31.1%	20.1%	35.6%	23.1%
Min	25.2%	18.6%	29.3%	19.6%	33.5%	20.9%
% of Average	94.8%	84.0%	94.4%	97.4%	94.1%	90.4%
Max	28.2%	24.6%	33.6%	21.1%	39.9%	25.9%
% of Average	106.1%	110.9%	108.0%	105.1%	112.0%	111.8%

Wind Power Statistics
1994-2000 Capacity Factor Summary by Month

Year	Diversified	Browning Depot, MT	Cape Blanco, OR	Goodnoe Hills Tower, WA	Kennewick, WA	Seven Mile Hill, OR
Jan	29.9%	34.6%	42.2%	19.8%	40.1%	13.0%
Feb	30.2%	32.3%	43.8%	18.9%	43.5%	12.2%
Mar	25.9%	22.3%	34.3%	17.1%	36.9%	18.8%
Apr	25.0%	17.1%	27.6%	21.8%	32.5%	25.8%
May	24.8%	14.6%	22.1%	22.2%	34.1%	30.8%
Jun	25.0%	13.0%	23.1%	23.5%	30.5%	35.0%
Jul	23.8%	11.4%	24.6%	21.2%	25.1%	36.7%
Aug	23.1%	11.1%	21.2%	22.2%	27.1%	33.7%
Sep	22.7%	14.9%	23.5%	18.7%	31.1%	25.3%
Oct	25.5%	24.4%	28.4%	19.8%	35.5%	19.6%
Nov	29.7%	32.2%	43.2%	18.9%	41.4%	12.7%
Dec	31.9%	38.3%	42.1%	20.7%	44.7%	13.9%
Average	26.5%	22.2%	31.3%	20.4%	35.2%	23.1%
Min	22.7%	11.1%	21.2%	17.1%	25.1%	12.2%
% of Average	85.7%	49.8%	67.7%	83.8%	71.2%	52.9%
Max	31.9%	38.3%	43.8%	23.5%	44.7%	36.7%
% of Average	120.7%	172.8%	139.9%	115.2%	127.1%	158.5%

Monthly Wind Generation Capacity Factor
1994-2000



Appendix

I

Capacity Expansion Process Details

AURORA™ ELECTRIC MARKET MODEL

Capacity Expansion

Overview

AURORA simulates the addition of new-generation resources and the economic retirement of existing units. New units are chosen from a set of available supply alternatives with technology and cost characteristics that can be specified through time. New resources are built only when the combination of hourly prices and frequency of operation for a resource generate enough revenue to make construction profitable; that is, when investors can recover fixed and variable costs with an acceptable return on investment. AURORA uses an iterative technique in these long-term planning studies to solve the interdependencies between prices and changes in resource schedules.

Also, existing units that cannot generate enough revenue to cover their variable and fixed operating costs over time are identified and become candidates for economic retirement. To reflect the timing of transition to competition across all areas, the rate at which existing units can be retired for economic reasons is constrained in these studies for a number of years.

Future-Capacity Expansion Process - The model uses market economics to determine the future resource retirements and additions. In simulating what happens in a competitive marketplace, AURORA produces a set of future resources that have value in the marketplace over the study period. Investors will only make future investments if they get a return of and return on their investment dollars. The model assumes that investors will invest to the point that they get their expected return. As future investments are made and new capacity is added, electricity prices will fall. The prices will continue to decline as long as investors are willing to make investments, and investors will invest as long as their projects have a positive net-present value taking consideration all going forward costs and return on investment. Hence, prices fall and at some point future investments no longer earn the expected return. Once that happens more investment will not be made, and without the investment prices are higher. This continues until the price for a market area is in equilibrium and the future resources for the study period have reached the point where last investment still has a positive net present value.

Capacity Expansion Modeling

In AURORA, future resource units may be put in the database with pre-determined start dates. Or, you can use the long-term optimization logic that uses market economics to determine the long-term resources and the start or retirement dates. Long-term optimization studies are used to forecast capacity expansion resources and retirements.

AURORA performs an iterative future analysis where 1) resources that have negative going-forward value (revenues less cost) are retired and 2) resources that add value are added to the system. This is done on a gradual basis—where resources with positive net present value are selected from the set of new resource options and added to the study. 3) AURORA then uses the new set of resources to compute all of the values again. 4) The process of adding and retiring resources is repeated. This whole process is continually repeated until value or system price stabilizes indicating that an optimal set of resources is identified for the future conditions assumed for the study.

The competitive marketplace will construct resources over the long-term such that there is an expectation that the new resource will create value on a going-forward basis. Likewise, existing resources that have no value on a going forward basis will eventually be retired within the constraints of the system. Existing and potential resources can be studied to see how well they will compete in the marketplace.

The goal of optimization process is to simulate the competitive marketplace by identifying the investments in future resources that have the value in the marketplace. AURORA assumes that new generators will be built (and existing generators retired) based on economics. The economic measure used is real levelized value (revenues less cost) on a $ per MW basis. Investment cost is included in the cost portion of the formula.

Also, the methodology assumes that potentially non-economic contracts will not influence the marketplace and that someone will capture the opportunity value of non-economic contracts. Therefore contracts are not modeled in the pricing piece of AURORA.

In preparing for Long-term optimization studies, users will identify new resource options to be evaluated in the study and determine parameters for the study.

NEW RESOURCES

The New Resources Table in the database is where the user defines a new resource and its operating characteristics. The types of resource may be Wind, Solar, Nuclear, Coal, or Gas. Also, new resources may include improved heat rates of existing technologies, re-deployment of existing resources and emerging technologies.

The new resources input defines the variables of a new unit, including when the potential unit will be placed in service. These variables provide controls for placing operating constraints on all the units in the system.

AURORA will calculate a value for each unit using an approach that enables resources to be compared on equal basis with different capacity sizes and different investment lives. This also handles the economic comparisons when the resource end of life extends beyond study period.

Therefore, investors are compensated for their investment and the economic decision holds for not only over the study period but also over the life of the resource project. The capital investment costs include:

- Rate of Return of attract capital investment
- Capital Recovery
- Income Tax Costs and Benefits

AURORA RESOURCE VALUE

AURORA determines resource value from the difference between market price and resource cost. The basic value formula is:

Market Value = Market Revenues
minus
Fuel Costs
Variable O&M Costs
Fixed O&M Costs
Emission Costs
Capital Investment Costs

This value determination is performed for every hour for every resource in each market region. Thus, a very accurate value is developed which takes into account system value during on peak and off-peak and other hours, and during daily, seasonal, and annual periods of time.

Incremental going forward costs and benefits: The user can specify the use of variable operation and maintenance expenses along with fixed operation and maintenance expense in the computation. However, the value computation should be performed on all forward costs. This produces the best economic view of the resource. In the table above, the carrying costs of the additional fixed operations and maintenances expense are calculated.

The resource value is computed as the present value of the hourly values over the study period. The present value is determined at the nominal discount rate.
In the resource selection, the value used for adding and retiring resources in AURORA is the net present value per MW capacity. This value is used to compare resources on equal basis to allow comparisons of resources with different capacity sizes and different investment lives. It also handles the economic comparisons when the resource end of life extends

beyond study period. Using this approach the result of the optimization study is a set of resources that have value in market. In summary, the net present value per MW of each resource is found for all periods of the study. This net present value is used in long term future analysis for determining whether a new resource should be added to the system or whether an old resource should be dropped.

SUMMARY OF STEPS IN CAPACITY EXPANSION STUDY

1. The first iteration begins with no changes in resources for the time period of the study. (AURORA uses resources in Resources Table)
2. Enumerates all new resources
3. Computes value for each existing resource
4. Computes value for each new enumerated resource
5. Sorts resource values
6. Selects a small set of the most negative value existing resources to retire
7. Selects a small set of the most positive value new resources to add.
8. Rerun AURORA to compute electric prices and resource value
9. AURORA repeats the algorithm until the system stabilizes

In this way, resources that create value on a going-forward basis will be constructed while those that have no value on a going forward basis will be retired. When the change in price achieves the optimization criteria for price change, and when at least the minimum study iterations are complete, the expansion study is complete. The minimum number of iterations is important to make sure a full range of capacity options have been explored out of thousands of potential resource options.

After the future resources have been identified, a resource modifier table is created—this table is used for other long-term studies. The new **RESOURCE MODIFIER** table becomes part of the AURORA input database. This table is the only output saved to the input database.

The output of the capacity expansion or long-term optimization study is used for other long-term analyses where the assumptions are applicable.

Appendix
J

Results of Capacity Expansion

Table J.1
Resource Retirements and Additions

Resource #	Name	Utility	Heat Rate	Capacity (kW)	Load Area	Begin Date	Retire Date
5959	Battle R 3	Alberta Power Limited	10502	157000	13	01-01-1980	12-31-2028
5960	Battle R 4	Alberta Power Limited	10500	157000	13	01-01-1980	12-31-2028
5962	Milner 1	Alberta Power Limited	10501	152000	13	01-01-1980	12-31-2028
5963	Rainbow 1 APL	Alberta Power Limited	10800	30000	13	01-01-1980	12-31-2025
5964	Rainbow 2 APL	Alberta Power Limited	10400	43000	13	01-01-1980	12-31-2025
5965	Rainbow 3 APL	Alberta Power Limited	11400	22000	13	01-01-1980	12-31-2028
5966	Sheerness 1	Alberta Power Limited	10353	389000	13	01-01-1980	12-31-2027
5968	Anaheim GT 1	Anaheim CA, City of	12800	48000	3	01-01-1980	12-31-2011
5970	Apache Station GT2	Arizona Electric Power Coopera	14362	20000	10	01-01-1980	12-31-2007
5971	Apache Station GT3	Arizona Electric Power Coopera	12990	69000	10	01-01-1980	12-31-2011
5972	Apache Station ST2	Arizona Electric Power Coopera	10293	175000	10	01-01-1980	12-31-2010
5973	Apache Station ST3	Arizona Electric Power Coopera	10293	175000	10	01-01-1980	12-31-2009
5977	Cholla 1	Arizona Public Service Company	10378	110000	10	01-01-1980	12-31-2028
5979	Cholla 3	Arizona Public Service Company	10399	260000	10	01-01-1980	12-31-2028
5981	Douglas 1	Arizona Public Service Company	13797	17000	10	01-01-1980	12-31-2007
5984	Four Corners 3	Arizona Public Service Company	11029	220000	9	01-01-1980	12-31-2028
5988	Ocotillo 1	Arizona Public Service Company	10782	115000	10	01-01-1980	12-31-2009
5989	Ocotillo 2	Arizona Public Service Company	10984	115000	10	01-01-1980	12-31-2008
5990	Ocotillo GT1	Arizona Public Service Company	14312	67000	10	01-01-1980	12-31-2009
5991	Ocotillo GT2	Arizona Public Service Company	15873	67000	10	01-01-1980	12-31-2005
5995	Saguaro 1 APSC	Arizona Public Service Company	11195	110000	10	01-01-1980	12-31-2008
5996	Saguaro 2	Arizona Public Service Company	11322	99000	10	01-01-1980	12-31-2008
5997	Saguaro GT1	Arizona Public Service Company	13623	64000	10	01-01-1980	12-31-2008
5998	Saguaro GT2	Arizona Public Service Company	13718	64000	10	01-01-1980	12-31-2008
6000	West Phoenix 1B	Arizona Public Service Company	9201	97000	10	01-01-1980	12-31-2011
6001	West Phoenix 2B	Arizona Public Service Company	9201	97000	10	01-01-1980	12-31-2011
6002	West Phoenix 3B	Arizona Public Service Company	9201	97000	10	01-01-1980	12-31-2011
6003	West Phoenix GT1	Arizona Public Service Company	13965	67000	10	01-01-1980	12-31-2007
6004	West Phoenix GT2	Arizona Public Service Company	13965	67000	10	01-01-1980	12-31-2007
6005	Yucca GT1	Arizona Public Service Company	14667	22000	10	01-01-1980	12-31-2006
6006	Yucca GT2	Arizona Public Service Company	14137	22000	10	01-01-1980	12-31-2006
6007	Yucca GT3	Arizona Public Service Company	11907	67000	10	01-01-1980	12-31-2013
6008	Yucca GT4	Arizona Public Service Company	12691	66000	10	01-01-1980	12-31-2010

Resource #	Name	Utility	Heat Rate	Capacity (kW)	Load Area	Begin Date	Retire Date
6009	Yucca ST1	Arizona Public Service Company	10190	75000	10	01-01-1980	12-31-2011
6018	Ben French 2	Black Hills Power & Light Comp	9240	2000	8	01-01-1980	12-31-2004
6019	Ben French 3	Black Hills Power & Light Comp	9240	2000	8	01-01-1980	12-31-2004
6020	Ben French 4	Black Hills Power & Light Comp	9240	2000	8	01-01-1980	12-31-2006
6021	Ben French 5	Black Hills Power & Light Comp	9240	2000	8	01-01-1980	12-31-2005
6022	Ben French GT1	Black Hills Power & Light Comp	12490	25000	8	01-01-1980	12-31-2007
6023	Ben French GT2	Black Hills Power & Light Comp	12490	25000	8	01-01-1980	12-31-2007
6024	Ben French GT3	Black Hills Power & Light Comp	12490	25000	8	01-01-1980	12-31-2007
6025	Ben French GT4	Black Hills Power & Light Comp	12490	25000	8	01-01-1980	12-31-2007
6026	Ben French IC1	Black Hills Power & Light Comp	9240	2000	8	01-01-1980	12-31-2004
6032	Osage 2	Black Hills Power & Light Comp	14750	10150	7	01-01-1980	12-31-2028
6033	Osage 3	Black Hills Power & Light Comp	14400	10150	7	01-01-1980	12-31-2028
6060	Boston Bar Diesel 1	British Columbia Hydro & Power	12000	2000	4	01-01-1980	12-31-2025
6065	Burrard Thermal 4	British Columbia Hydro & Power	12500	157000	4	01-01-1980	12-31-2025
6066	Burrard Thermal 5	British Columbia Hydro & Power	12500	157000	4	01-01-1980	12-31-2012
6067	Burrard Thermal 6	British Columbia Hydro & Power	12500	163000	4	01-01-1980	12-31-2009
6077	Keogh GT2	British Columbia Hydro & Power	12600	50000	4	01-01-1980	12-31-2024
6081	Lytton Diesel 1	British Columbia Hydro & Power	11500	3450	4	01-01-1980	12-31-2024
6101	Magnolia 4	Burbank Public Service Departm	11100	32000	3	01-01-1980	12-31-2011
6102	Magnolia 5	Burbank Public Service Departm	10010	22000	3	01-01-1980	12-31-2028
6103	Olive 1	Burbank Public Service Departm	10918	46000	3	01-01-1980	12-31-2011
6104	Olive 2	Burbank Public Service Departm	10080	60000	3	01-01-1980	12-31-2026
6105	Olive 3	Burbank Public Service Departm	14339	24000	3	01-01-1980	12-31-2011
6301	Cheyenne Diesel 1	Cheyenne Light Fuel & Power Co	14000	2000	7	01-01-1980	12-31-2005
6302	Cheyenne Diesel 2	Cheyenne Light Fuel & Power Co	14000	2000	7	01-01-1980	12-31-2006
6303	Cheyenne Diesel 3	Cheyenne Light Fuel & Power Co	14000	2000	7	01-01-1980	12-31-2006
6304	Cheyenne Diesel 4	Cheyenne Light Fuel & Power Co	14000	2000	7	01-01-1980	12-31-2005
6305	Cheyenne Diesel 5	Cheyenne Light Fuel & Power Co	14000	2000	7	01-01-1980	12-31-2006
6306	Valencia GT1	Citizens Utilities Company - A	15445	15800	10	01-01-1980	12-31-2006
6307	Valencia GT2	Citizens Utilities Company - A	16647	15800	10	01-01-1980	12-31-2006
6308	Valencia GT3	Citizens Utilities Company - A	15957	16000	10	01-01-1980	12-31-2006
6310	George Birdsall 1	Colorado Springs Utilities - C	13500	16000	8	01-01-1980	12-31-2006
6311	George Birdsall 2	Colorado Springs Utilities - C	13500	17000	8	01-01-1980	12-31-2006
6312	George Birdsall 3	Colorado Springs Utilities - C	13500	23000	8	01-01-1980	12-31-2007
6315	Martin Drake 4	Colorado Springs Utilities - C	14800	11000	8	01-01-1980	12-31-2004
6365	Bonanza 1	Deseret Generation & Transmiss	10463	420000	11	01-01-1980	12-31-2028
6371	Clover Bar 1	Edmonton Power	12500	165000	13	01-01-1980	12-31-2009
6372	Clover Bar 2	Edmonton Power	12500	165000	13	01-01-1980	12-31-2009
6373	Clover Bar 3	Edmonton Power	12500	165000	13	01-01-1980	12-31-2007
6374	Clover Bar 4	Edmonton Power	12500	165000	13	01-01-1980	12-31-2025
6376	Genesee 2	Edmonton Power	10352	406000	13	01-01-1980	12-31-2028
6377	Rossdale 10	Edmonton Power	14000	72000	13	01-01-1980	12-31-2008
6378	Rossdale 8	Edmonton Power	14000	71000	13	01-01-1980	12-31-2008
6379	Rossdale 9	Edmonton Power	14000	73000	13	01-01-1980	12-31-2007
6380	Copper 1	El Paso Electric Company	15800	71000	9	01-01-1980	12-31-2005
6381	Newman 1	El Paso Electric Company	10300	83000	9	01-01-1980	12-31-2011
6382	Newman 2	El Paso Electric Company	10300	82000	9	01-01-1980	12-31-2011

Resource #	Name	Utility	Heat Rate	Capacity (kW)	Load Area	Begin Date	Retire Date
6383	Newman 3	El Paso Electric Company	9900	104000	9	01-01-1980	12-31-2011
6384	Newman CC -- 4+CT1+CT2	El Paso Electric Company	8800	240000	9	01-01-1980	12-31-2013
6385	Rio Grande 6	El Paso Electric Company	11300	48000	9	01-01-1980	12-31-2007
6386	Rio Grande 7	El Paso Electric Company	10500	48000	9	01-01-1980	12-31-2009
6387	Rio Grande 8	El Paso Electric Company	9800	151000	9	01-01-1980	12-31-2013
6419	Animas 3	Farmington NM, City of	13500	9000	9	01-01-1980	12-31-2004
6420	Animas 4	Farmington NM, City of	13000	16000	9	01-01-1980	12-31-2005
6430	Grayson 3	Glendale CA, City of Public Se	13000	19000	3	01-01-1980	12-31-2009
6431	Grayson 4	Glendale CA, City of Public Se	11600	44000	3	01-01-1980	12-31-2011
6432	Grayson 5	Glendale CA, City of Public Se	10500	42000	3	01-01-1980	12-31-2013
6433	Grayson 6	Glendale CA, City of Public Se	13000	18000	3	01-01-1980	12-31-2011
6434	Grayson 7	Glendale CA, City of Public Se	12500	21000	3	01-01-1980	12-31-2010
6507	Brawley 1	Imperial Irrigation District -	17600	11000	3	01-01-1980	12-31-2007
6508	Brawley 2	Imperial Irrigation District -	17600	11000	3	01-01-1980	12-31-2007
6509	Coachella 1	Imperial Irrigation District -	14400	20000	3	01-01-1980	12-31-2004
6510	Coachella 2	Imperial Irrigation District -	14400	20000	3	01-01-1980	12-31-2011
6511	Coachella 3	Imperial Irrigation District -	14400	20000	3	01-01-1980	12-31-2011
6512	Coachella 4	Imperial Irrigation District -	14400	20000	3	01-01-1980	12-31-2010
6527	El Centro 3	Imperial Irrigation District -	11500	48000	3	01-01-1980	12-31-2011
6532	Rockwood 1	Imperial Irrigation District -	13400	25000	3	01-01-1980	12-31-2011
6533	Rockwood 2	Imperial Irrigation District -	13400	25000	3	01-01-1980	12-31-2011
6535	Yuma Axis 1	Imperial Irrigation District -	14100	20000	10	01-01-1980	12-31-2007
6539	Lamar Plt 4	Lamar CO, City of	12465	25000	8	01-01-1980	12-31-2007
6549	Logan City 4	Logan UT, City of	15456	700	11	01-01-1980	12-31-2004
6550	Logan City 5A	Logan UT, City of	7840	1100	11	01-01-1980	12-31-2028
6552	Logan City 6	Logan UT, City of	14684	2250	11	01-01-1980	12-31-2005
6579	Haynes 2	Los Angeles Department of Wate	9578	222000	3	01-01-1980	12-31-2025
6582	Haynes 5	Los Angeles Department of Wate	9543	341000	3	01-01-1980	12-31-2025
6603	Scattergood 1	Los Angeles Department of Wate	9697	179000	3	01-01-1980	12-31-2025
6604	Scattergood 2	Los Angeles Department of Wate	9795	179000	3	01-01-1980	12-31-2025
6616	Valley 3	Los Angeles Department of Wate	10685	163000	3	01-01-1980	12-31-2011
6617	Valley 4	Los Angeles Department of Wate	10487	160000	3	01-01-1980	12-31-2012
6626	Medicine Hat 10	Medicine Hat, City of	11300	18000	13	01-01-1980	12-31-2025
6627	Medicine Hat 11	Medicine Hat, City of	11300	18000	13	01-01-1980	12-31-2025
6628	Medicine Hat 12	Medicine Hat, City of	16500	32000	13	01-01-1980	12-31-2008
6629	Medicine Hat 3	Medicine Hat, City of	17000	16000	13	01-01-1980	12-31-2006
6630	Medicine Hat 4	Medicine Hat, City of	18000	3000	13	01-01-1980	12-31-2004
6631	Medicine Hat 5	Medicine Hat, City of	11200	19000	13	01-01-1980	12-31-2025
6632	Medicine Hat 6	Medicine Hat, City of	18000	5000	13	01-01-1980	12-31-2005
6633	Medicine Hat 7	Medicine Hat, City of	16500	32000	13	01-01-1980	12-31-2008
6634	Medicine Hat 8	Medicine Hat, City of	10500	40000	13	01-01-1980	12-31-2025
6635	Medicine Hat 9	Medicine Hat, City of	10500	40000	13	01-01-1980	12-31-2025
6753	Allen GT1	Nevada Power Company - NV	12500	76000	14	01-01-1980	12-31-2010
6754	Clark 1	Nevada Power Company - NV	11100	42000	14	01-01-1980	12-31-2009
6755	Clark 2	Nevada Power Company - NV	10350	69000	14	01-01-1980	12-31-2009
6756	Clark 3	Nevada Power Company - NV	11400	70000	14	01-01-1980	12-31-2009
6758	Clark GT4	Nevada Power Company - NV	13000	59000	14	01-01-1980	12-31-2011

Resource #	Name	Utility	Heat Rate	Capacity (kW)	Load Area	Begin Date	Retire Date
6767	Sun-Peak 1	Nevada Power Company - NV	12300	70000	14	01-01-1980	12-31-2012
6768	Sun-Peak 2	Nevada Power Company - NV	12300	70000	14	01-01-1980	12-31-2012
6769	Sun-Peak 3	Nevada Power Company - NV	12300	70000	14	01-01-1980	12-31-2012
6771	Sunrise 2	Nevada Power Company - NV	13100	76000	14	01-01-1980	12-31-2011
6772	Alameda 1	Northern California Power Agen	16500	25000	2	01-01-1980	12-31-2004
6773	Alameda 2	Northern California Power Agen	16500	25000	2	01-01-1980	12-31-2004
6785	Lodi 1	Northern California Power Agen	14650	25000	2	01-01-1980	12-31-2005
6787	Roseville 1	Northern California Power Agen	15750	25000	2	01-01-1980	12-31-2004
6788	Roseville 2	Northern California Power Agen	15750	25000	2	01-01-1980	12-31-2004
6817	Contra Costa 6	Mirant	9385	340000	2	01-01-1980	12-31-2010
6818	Contra Costa 7	Mirant	9555	340000	2	01-01-1980	12-31-2010
6827	Downieville 1	Pacific Gas & Electric Company	13088	750	2	01-01-1980	12-31-2028
6859	Humboldt Bay 1	Pacific Gas & Electric Company	11913	52000	2	01-01-1980	12-31-2005
6860	Humboldt Bay 2	Pacific Gas & Electric Company	12352	53000	2	01-01-1980	12-31-2004
6861	Humboldt Bay GT2	Pacific Gas & Electric Company	14000	15000	2	01-01-1980	12-31-2005
6862	Humboldt Bay GT3	Pacific Gas & Electric Company	14000	15000	2	01-01-1980	12-31-2005
6863	Hunters Point 2	Pacific Gas & Electric Company	13134	107000	2	01-01-1980	12-31-2005
6864	Hunters Point 3	Pacific Gas & Electric Company	12582	107000	2	01-01-1980	12-31-2005
6865	Hunters Point 4	Pacific Gas & Electric Company	9759	163000	2	01-01-1980	12-31-2010
6866	Hunters Point GT1	Pacific Gas & Electric Company	12080	52000	2	01-01-1980	12-31-2006
6878	Mobile GT 1	Pacific Gas & Electric Company	14000	15000	2	01-01-1980	12-31-2024
6879	Mobile GT 2	Pacific Gas & Electric Company	14000	15000	2	01-01-1980	12-31-2024
6880	Mobile GT 3	Pacific Gas & Electric Company	14000	15000	2	01-01-1980	12-31-2024
6882	Morro Bay 1	Duke Energy	10293	163000	3	01-01-1980	12-31-2013
6883	Morro Bay 2	Duke Energy	10207	163000	3	01-01-1980	12-31-2025
6886	Moss Landing 6	Duke Energy	8882	739000	2	01-01-1980	12-31-2010
6887	Moss Landing 7	Duke Energy	8981	739000	2	01-01-1980	12-31-2012
6891	Oakland 1	Duke Energy	12080	55000	2	01-01-1980	12-31-2007
6892	Oakland 2	Duke Energy	12080	55000	2	01-01-1980	12-31-2009
6893	Oakland 3	Duke Energy	12080	55000	2	01-01-1980	12-31-2009
6901	Pittsburg 1	SEI	10445	163000	2	01-01-1980	12-31-2005
6902	Pittsburg 2	SEI	10161	163000	2	01-01-1980	12-31-2007
6903	Pittsburg 3	SEI	10410	163000	2	01-01-1980	12-31-2005
6904	Pittsburg 4	SEI	10371	163000	2	01-01-1980	12-31-2006
6905	Pittsburg 5	SEI	9653	325000	2	01-01-1980	12-31-2009
6906	Pittsburg 6	SEI	9625	325000	2	01-01-1980	12-31-2009
6907	Pittsburg 7	SEI	9697	720000	2	01-01-1980	12-31-2008
6954	Blundell 1	PacifiCorp	21248	23000	11	01-01-1980	12-31-2010
6956	Carbon 1	PacifiCorp	11200	70000	11	01-01-1980	12-31-2028
6957	Carbon 2	PacifiCorp	10500	105000	11	01-01-1980	12-31-2028
6975	Dave Johnston 2	PacifiCorp	10900	106000	7	01-01-1980	12-31-2028
6976	Dave Johnston 3	PacifiCorp	10700	230000	7	01-01-1980	12-31-2028
6985	Gadsby 1	PacifiCorp	11500	60000	11	01-01-1980	12-31-2004
6986	Gadsby 2	PacifiCorp	11200	75000	11	01-01-1980	12-31-2006
6987	Gadsby 3	PacifiCorp	10500	100000	11	01-01-1980	12-31-2006
7013	Little Mountain 1	PacifiCorp	14500	14000	11	01-01-1980	12-31-2006
7080	Broadway 1	Pasadena CA, City of	11750	42000	3	01-01-1980	12-31-2008

Resource #	Name	Utility	Heat Rate	Capacity (kW)	Load Area	Begin Date	Retire Date
7081	Broadway 2	Pasadena CA, City of	11200	42000	3	01-01-1980	12-31-2011
7082	Broadway 3	Pasadena CA, City of	10500	66000	3	01-01-1980	12-31-2013
7083	Glenarm GT1	Pasadena CA, City of	12200	26000	3	01-01-1980	12-31-2018
7084	Glenarm GT2	Pasadena CA, City of	12200	26000	3	01-01-1980	12-31-2018
7143	Bonnett 1#1	Provo City Corp - UT	41482	750	11	01-01-1980	12-31-2004
7144	Bonnett 1#2	Provo City Corp - UT	41482	750	11	01-01-1980	12-31-2004
7145	Bonnett 1#3	Provo City Corp - UT	41482	750	11	01-01-1980	12-31-2004
7146	Bonnett 1#4	Provo City Corp - UT	41482	750	11	01-01-1980	12-31-2004
7147	Bonnett 2	Provo City Corp - UT	41482	2000	11	01-01-1980	12-31-2004
7148	Bonnett 3	Provo City Corp - UT	41482	7000	11	01-01-1980	12-31-2004
7154	Alamosa CT1	Public Service Company of Colo	15070	17000	8	01-01-1980	12-31-2009
7155	Alamosa CT2	Public Service Company of Colo	14060	19000	8	01-01-1980	12-31-2009
7158	Arapahoe 1	Public Service Company of Colo	11730	45000	8	01-01-1980	12-31-2028
7159	Arapahoe 2	Public Service Company of Colo	11700	45000	8	01-01-1980	12-31-2028
7171	Cameo 1	Public Service Company of Colo	12440	23700	8	01-01-1980	12-31-2028
7177	Cherokee IC1	Public Service Company of Colo	14000	2750	8	01-01-1980	12-31-2006
7178	Cherokee IC2	Public Service Company of Colo	14000	2750	8	01-01-1980	12-31-2006
7184	Fort Lupton 1	Public Service Company of Colo	14150	50000	8	01-01-1980	12-31-2009
7185	Fort Lupton 2	Public Service Company of Colo	13970	50000	8	01-01-1980	12-31-2009
7186	Fruita 1	Public Service Company of Colo	14820	20000	8	01-01-1980	12-31-2009
7216	Valmont 5	Public Service Company of Colo	10050	189000	8	01-01-1980	12-31-2008
7217	Valmont 6	Public Service Company of Colo	13160	53000	8	01-01-1980	12-31-2010
7219	Zuni 1	Public Service Company of Colo	13630	39000	8	01-01-1980	12-31-2007
7220	Zuni 2	Public Service Company of Colo	13440	68000	8	01-01-1980	12-31-2007
7221	Las Vegas 1	Public Service Company of New	15752	20000	9	01-01-1980	12-31-2004
7222	Reeves 1	Public Service Company of New	11143	44000	9	01-01-1980	12-31-2009
7223	Reeves 2	Public Service Company of New	10972	44000	9	01-01-1980	12-31-2009
7224	Reeves 3	Public Service Company of New	14690	66000	9	01-01-1980	12-31-2006
7225	San Juan 1	Public Service Company of New	11255	316000	9	01-01-1980	12-31-2028
7226	San Juan 2	Public Service Company of New	12869	312000	9	01-01-1980	12-31-2006
7227	San Juan 3	Public Service Company of New	12258	488000	9	01-01-1980	12-31-2012
7338	Raton 4	Raton Public Service Company -	18100	4000	9	01-01-1980	12-31-2004
7339	Raton 5	Raton Public Service Company -	14200	8000	9	01-01-1980	12-31-2005
7357	McClellan 1	Sacramento Municipal Utility D	13695	50000	2	01-01-1980	12-31-2012
7379	Agua Fria 1	Salt River Project - AZ	10277	114000	10	01-01-1980	12-31-2010
7380	Agua Fria 2	Salt River Project - AZ	10346	114000	10	01-01-1980	12-31-2007
7381	Agua Fria 3	Salt River Project - AZ	10055	184000	10	01-01-1980	12-31-2011
7382	Agua Fria 4	Salt River Project - AZ	11788	87000	10	01-01-1980	12-31-2013
7383	Agua Fria 5	Salt River Project - AZ	13524	75000	10	01-01-1980	12-31-2010
7384	Agua Fria 6	Salt River Project - AZ	13044	75000	10	01-01-1980	12-31-2011
7392	Kyrene 1	Salt River Project - AZ	12827	34000	10	01-01-1980	12-31-2007
7393	Kyrene 2	Salt River Project - AZ	11323	72000	10	01-01-1980	12-31-2008
7394	Kyrene KY4	Salt River Project - AZ	13502	69000	10	01-01-1980	12-31-2009
7395	Kyrene KY5	Salt River Project - AZ	12867	61000	10	01-01-1980	12-31-2011
7396	Kyrene KY6	Salt River Project - AZ	13067	60000	10	01-01-1980	12-31-2010
7403	Santan 1	Salt River Project - AZ	9276	87000	10	01-01-1980	12-31-2012
7404	Santan 2	Salt River Project - AZ	8894	85000	10	01-01-1980	12-31-2011

Resource #	Name	Utility	Heat Rate	Capacity (kW)	Load Area	Begin Date	Retire Date
7412	Division 1	San Diego Gas & Electric Compa	16000	19000	3	01-01-1980	12-31-2006
7413	El Cajon 1	San Diego Gas & Electric Compa	16300	20000	3	01-01-1980	12-31-2004
7414	Encina 1	Dynegy and NRG	10300	107000	3	01-01-1980	12-31-2008
7415	Encina 2	Dynegy and NRG	10300	104000	3	01-01-1980	12-31-2008
7416	Encina 3	Dynegy and NRG	10400	110000	3	01-01-1980	12-31-2007
7417	Encina 4	Dynegy and NRG	10200	300000	3	01-01-1980	12-31-2006
7418	Encina 5	Dynegy and NRG	9620	330000	3	01-01-1980	12-31-2011
7419	Encina GT1	Dynegy and NRG	16800	18000	3	01-01-1980	12-31-2004
7422	Kearny 1	San Diego Gas & Electric Compa	15500	20000	3	01-01-1980	12-31-2006
7423	Kearny 2	San Diego Gas & Electric Compa	16400	78000	3	01-01-1980	12-31-2004
7424	Kearny 3	San Diego Gas & Electric Compa	16200	78000	3	01-01-1980	12-31-2006
7425	Miramar 1	San Diego Gas & Electric Compa	15100	47000	3	01-01-1980	12-31-2006
7427	Naval Training Ctr 1	Sithe	15500	20000	3	01-01-1980	12-31-2004
7428	North Island 1	San Diego Gas & Electric Compa	15100	22000	3	01-01-1980	12-31-2006
7429	North Island 2	San Diego Gas & Electric Compa	15100	22000	3	01-01-1980	12-31-2006
7430	South Bay 1	DENA - Port of San Diego	9500	146000	3	01-01-1980	12-31-2010
7431	South Bay 2	DENA - Port of San Diego	9800	150000	3	01-01-1980	12-31-2009
7432	South Bay 3	DENA - Port of San Diego	9900	175000	3	01-01-1980	12-31-2010
7433	South Bay 4	DENA - Port of San Diego	11400	222000	3	01-01-1980	12-31-2007
7434	South Bay GT1	DENA - Port of San Diego	13400	22000	3	01-01-1980	12-31-2006
7480	Battle Mtn 1	Sierra Pacific Power Company -	10180	2000	12	01-01-1980	12-31-2025
7481	Battle Mtn 2	Sierra Pacific Power Company -	10180	2000	12	01-01-1980	12-31-2025
7482	Battle Mtn 3	Sierra Pacific Power Company -	10180	2000	12	01-01-1980	12-31-2025
7483	Battle Mtn 4	Sierra Pacific Power Company -	10180	2000	12	01-01-1980	12-31-2025
7485	Brunswick 1	Sierra Pacific Power Company -	10428	2000	12	01-01-1980	12-31-2025
7486	Brunswick 2	Sierra Pacific Power Company -	10428	2000	12	01-01-1980	12-31-2025
7487	Brunswick 3	Sierra Pacific Power Company -	10428	2000	12	01-01-1980	12-31-2025
7498	Fort Churchill 1	Sierra Pacific Power Company -	10183	113000	12	01-01-1980	12-31-2009
7499	Fort Churchill 2	Sierra Pacific Power Company -	10295	113000	12	01-01-1980	12-31-2010
7502	Kings Beach 1	Sierra Pacific Power Company -	11100	2750	2	01-01-1980	12-31-2028
7503	Kings Beach 2	Sierra Pacific Power Company -	11100	2750	2	01-01-1980	12-31-2028
7504	Kings Beach 3	Sierra Pacific Power Company -	11100	2750	2	01-01-1980	12-31-2028
7505	Kings Beach 4	Sierra Pacific Power Company -	11100	2750	2	01-01-1980	12-31-2028
7506	Kings Beach 5	Sierra Pacific Power Company -	11100	2750	2	01-01-1980	12-31-2028
7507	Kings Beach 6	Sierra Pacific Power Company -	11100	2750	2	01-01-1980	12-31-2028
7514	Portola 1	Sierra Pacific Power Company -	10336	2000	2	01-01-1980	12-31-2028
7515	Portola 2	Sierra Pacific Power Company -	10336	2000	2	01-01-1980	12-31-2028
7516	Portola 3	Sierra Pacific Power Company -	10336	2000	2	01-01-1980	12-31-2028
7522	Tracy 3	Sierra Pacific Power Company -	10423	108000	12	01-01-1980	12-31-2008
7523	Tracy 4	Sierra Pacific Power Company -	11971	83000	12	01-01-1980	12-31-2012
7524	Tracy GT1	Sierra Pacific Power Company -	15300	11000	12	01-01-1980	12-31-2007
7525	Tracy GT2	Sierra Pacific Power Company -	15000	11000	12	01-01-1980	12-31-2007
7526	Tracy GT3	Sierra Pacific Power Company -	11819	83000	12	01-01-1980	12-31-2010
7527	Tracy ST1	Sierra Pacific Power Company -	12220	53000	12	01-01-1980	12-31-2007
7528	Tracy ST2	Sierra Pacific Power Company -	11066	83000	12	01-01-1980	12-31-2009
7529	Valley Road 1	Sierra Pacific Power Company -	10215	2000	12	01-01-1980	12-31-2025
7530	Valley Road 2	Sierra Pacific Power Company -	10215	2000	12	01-01-1980	12-31-2025

Resource #	Name	Utility	Heat Rate	Capacity (kW)	Load Area	Begin Date	Retire Date
7531	Valley Road 3	Sierra Pacific Power Company -	10215	2000	12	01-01-1980	12-31-2025
7532	Valmy 1	Sierra Pacific Power Company -	10047	258000	12	01-01-1980	12-31-2028
7537	Winnemucca 1	Sierra Pacific Power Company -	15900	15000	12	01-01-1980	12-31-2008
7543	Alamitos 1	Williams Energy	10956	175000	3	01-01-1980	12-31-2013
7544	Alamitos 2	Williams Energy	10658	175000	3	01-01-1980	12-31-2012
7545	Alamitos 3	Williams Energy	10236	320000	3	01-01-1980	12-31-2025
7546	Alamitos 4	Williams Energy	9690	320000	3	01-01-1980	12-31-2012
7549	Alamitos 7	Williams Energy	18510	147000	3	01-01-1980	12-31-2007
7589	Alta Power 1 (Coolwater)	Reliant Energy	10428	65000	3	01-01-1980	12-31-2011
7590	Alta Power 2 (Coolwater)	Reliant Energy	10430	81000	3	01-01-1980	12-31-2013
7593	El Segundo 1	Dynegy and NRG	10667	175000	3	01-01-1980	12-31-2010
7594	El Segundo 2	Dynegy and NRG	10620	175000	3	01-01-1980	12-31-2011
7595	El Segundo 3	Dynegy and NRG	9723	335000	3	01-01-1980	12-31-2011
7596	El Segundo 4	Dynegy and NRG	9593	335000	3	01-01-1980	12-31-2012
7597	Ellwood 1	Southern California Edison Com	14950	53000	3	01-01-1980	12-31-2009
7598	Mountain Vista 1 (Etiwanda)	Reliant Energy	11143	132000	3	01-01-1980	12-31-2011
7599	Mountain Vista 2 (Etiwanda)	Reliant Energy	11151	132000	3	01-01-1980	12-31-2010
7600	Mountain Vista 3 (Etiwanda)	Reliant Energy	9616	320000	3	01-01-1980	12-31-2012
7601	Mountain Vista 4 (Etiwanda)	Reliant Energy	9601	320000	3	01-01-1980	12-31-2013
7602	Mountain Vista GT5 (Etiwanda)	Reliant Energy	20006	142000	3	01-01-1980	12-31-2005
7605	Riverside Canal Power Co 1	THERMO ECOTEK	13280	32000	3	01-01-1980	12-31-2008
7606	Riverside Canal Power Co 2	THERMO ECOTEK	13280	33000	3	01-01-1980	12-31-2008
7607	Riverside Canal Power Co 3	THERMO ECOTEK	12320	44000	3	01-01-1980	12-31-2009
7608	Riverside Canal Power Co 4	THERMO ECOTEK	12300	45000	3	01-01-1980	12-31-2010
7609	Huntington Beach 1	AES	9613	225000	3	01-01-1980	12-31-2012
7610	Huntington Beach 2	AES	9775	225000	3	01-01-1980	12-31-2012
7611	Huntington Beach GT5	AES	19997	110000	3	01-01-1980	12-31-2007
7634	Ocean Vista 1 (Mandalay)	Reliant Energy	9519	215000	3	01-01-1980	12-31-2013
7635	Ocean Vista 2 (Mandalay)	Reliant Energy	9579	215000	3	01-01-1980	12-31-2012
7636	Ocean Vista 3 (Mandalay)	Reliant Energy	14393	147000	3	01-01-1980	12-31-2011
7665	Redondo Beach 5	AES	10374	175000	3	01-01-1980	12-31-2013
7666	Redondo Beach 6	AES	10716	175000	3	01-01-1980	12-31-2010
7667	Redondo Beach 7	AES	9559	480000	3	01-01-1980	12-31-2013
7668	Redondo Beach 8	AES	9500	480000	3	01-01-1980	12-31-2013
7671	MOUNTAINVIEW 1	THERMO ECOTEK	11523	63000	3	01-01-1980	12-31-2011
7672	MOUNTAINVIEW 2	THERMO ECOTEK	11577	63000	3	01-01-1980	12-31-2011
7733	Sundance 1	TransAlta Utilities Corporatio	10401	293000	13	01-01-1980	12-31-2028
7734	Sundance 2	TransAlta Utilities Corporatio	10400	294000	13	01-01-1980	12-31-2028
7737	Sundance 5	TransAlta Utilities Corporatio	10358	371000	13	01-01-1980	12-31-2028
7739	Wabamun 1	TransAlta Utilities Corporatio	11501	67000	13	01-01-1980	12-31-2027
7740	Wabamun 2	TransAlta Utilities Corporatio	11500	67000	13	01-01-1980	12-31-2027
7741	Wabamun 3	TransAlta Utilities Corporatio	10503	147000	13	01-01-1980	12-31-2027
7742	Wabamun 4	TransAlta Utilities Corporatio	10402	293000	13	01-01-1980	12-31-2027
7745	Trinidad 4	Trinidad CO, City of	13000	3000	8	01-01-1980	12-31-2005
7750	Nucla 1	Tri-State Generation & Transmi	11670	12000	8	01-01-1980	12-31-2028
7751	Nucla 2	Tri-State Generation & Transmi	11670	12000	8	01-01-1980	12-31-2028
7752	Nucla 3	Tri-State Generation & Transmi	11670	12000	8	01-01-1980	12-31-2028

Resource #	Name	Utility	Heat Rate	Capacity (kW)	Load Area	Begin Date	Retire Date
7754	Irvington 1	Tucson Electric Power Company	9864	81000	10	01-01-1980	12-31-2010
7755	Irvington 2	Tucson Electric Power Company	10182	81000	10	01-01-1980	12-31-2011
7756	Irvington 3	Tucson Electric Power Company	10822	105000	10	01-01-1980	12-31-2008
7757	Irvington 4	Tucson Electric Power Company	10219	156000	10	01-01-1980	12-31-2007
7758	Irvington GT1	Tucson Electric Power Company	15000	24000	10	01-01-1980	12-31-2009
7759	Irvington GT2	Tucson Electric Power Company	15000	25000	10	01-01-1980	12-31-2009
7760	Irvington GT3	Tucson Electric Power Company	15000	25000	10	01-01-1980	12-31-2009
7761	North Loop 1	Tucson Electric Power Company	15000	25000	10	01-01-1980	12-31-2006
7762	North Loop 2	Tucson Electric Power Company	15000	25000	10	01-01-1980	12-31-2009
7763	North Loop 3	Tucson Electric Power Company	15000	23000	10	01-01-1980	12-31-2009
7936	Los Alamos Unit 1	US ERDA-Los Alamos Area Office	14024	5000	9	01-01-1980	12-31-2004
7937	Los Alamos Unit 2	US ERDA-Los Alamos Area Office	14024	4000	9	01-01-1980	12-31-2004
7938	Los Alamos Unit 3	US ERDA-Los Alamos Area Office	13475	9000	9	01-01-1980	12-31-2004
7945	Vernon VER1	Vernon CA, City of	8000	4200	3	01-01-1980	12-31-2028
7946	Vernon VER2	Vernon CA, City of	8000	4200	3	01-01-1980	12-31-2028
7947	Vernon VER3	Vernon CA, City of	8000	4200	3	01-01-1980	12-31-2028
7948	Vernon VER4	Vernon CA, City of	8000	4200	3	01-01-1980	12-31-2028
7949	Vernon VER5	Vernon CA, City of	8000	4200	3	01-01-1980	12-31-2028
7950	Vernon VER6	Vernon CA, City of	12200	5400	3	01-01-1980	12-31-2018
7951	Vernon VER7	Vernon CA, City of	12200	5400	3	01-01-1980	12-31-2018
8006	Pueblo 6	West Plains Energy	13700	20000	8	01-01-1980	12-31-2007
8017	W N Clark 1	West Plains Energy	13100	17000	8	01-01-1980	12-31-2028
8018	W N Clark 2	West Plains Energy	12690	24000	8	01-01-1980	12-31-2028
8103	Aurora Project GTG - Mildred Lake AB	Syncrude	8800	80000	13	07-07-2000	12-31-2025
8118	Delta-Person Project (Albuquerque)	Delta Energy+John Hancock Life	8750	140000	9	05-01-2000	12-31-2011
8121	Drywood Plant	Canadian Hydro	9000	6000	13	09-01-1999	12-31-2025
8129	Fort St Vrain Phase 1 repowering	New Century Energies	8800	240000	8	05-01-1998	12-31-2013
8130	Fort St Vrain Phase 2	New Century Energies	8800	240000	8	05-01-1999	12-31-2013
8134	Fredonia 1	Puget Sound Energy - WA	10711	123636	1	01-01-1980	12-31-2008
8135	Fredonia 2	Puget Sound Energy - WA	10711	123636	1	01-01-1980	12-31-2008
8137	Gold Creek power plant	TransCanada	9000	6000	13	07-01-2000	12-31-2025
8155	Poplar Hill	ATCO Power (IPP)	9503	43000	13	06-30-1999	12-31-2025
8157	Rainbow Lake (ATCO Power)	ATCO Power (IPP)	9503	43000	13	06-30-1999	12-31-2025
8172	Whitehorn 2	Puget Sound Energy - WA	10600	88879	1	01-01-1980	12-31-2009
8173	Whitehorn 3	Puget Sound Energy - WA	10600	88879	1	01-01-1980	12-31-2009
8270	COSO ENERGY DEV 4-6 CAL	CAITHNESS ENERGY LLC	20000	84000	3	01-01-1980	12-31-2028
8271	COSO ENERGY DEV 7-9 CAL	CAITHNESS ENERGY LLC	20000	76000	3	01-01-1980	12-31-2028
8272	COSO FINANCE PARTNERS 1- 3	CAITHNESS ENERGY LLC	20000	80000	3	01-01-1980	12-31-2028
8285	DEL RANCH LTD NILAND#2	CALENERGY	20000	38000	3	01-01-1980	12-31-2028
8307	ELMORE LTD	CALENERGY	20000	38000	3	01-01-1980	12-31-2028
8334	GEM RESOURCES A	GEO EAST MESA LIMITED PARTNERS	20000	20000	3	01-01-1980	12-31-2028
8335	GEM RESOURCES B	GEO EAST MESA LIMITED PARTNERS	20000	20000	3	01-01-1980	12-31-2028
8372	HEBER GEO	CALPINE/ERC	20000	47000	3	01-01-1980	12-31-2028
8408	LEATHERS LP	CALENERGY	20000	38000	3	01-01-1980	12-31-2028
8501	ORMESA GEOTHERMAL II	FPL ENERGY, INC	20000	18500	3	01-01-1980	12-31-2028

Resource #	Name	Utility	Heat Rate	Capacity (kW)	Load Area	Begin Date	Retire Date
8502	ORMESA I IE IH	OESI POWER CORPORATION	20000	24000	3	01-01-1980	12-31-2028
8503	ORMESA IE	OESI POWER CORPORATION	20000	38000	3	01-01-1980	12-31-2028
8504	ORMESA IH	OESI POWER CORPORATION	20000	6500	3	01-01-1980	12-31-2028
8592	SECOND IMPERIAL GEO	OGDEN POWER CORPORATION	20000	37000	3	01-01-1980	12-31-2028
8684	Valley 1	Los Angeles Department of Wate	10685	95000	3	01-01-1980	12-31-2011
8685	Valley 2	Los Angeles Department of Wate	10685	99000	3	01-01-1980	12-31-2011
8692	VULCAN BN GEO	CALENERGY	20000	34000	3	01-01-1980	12-31-2028
8745	Biosphere 2 Center #G-4	Decisions Investments Corp	10000	1500	10	04-01-2000	12-31-2004
8747	Holly #5	Holly City of	10000	400	8	06-01-2000	12-31-2005
8755	Athol	Kootenai Electric	10000	1640	1	03-01-2001	12-31-2028
8756	Bains	Bains, LLC	10000	2500	1	05-01-2001	12-31-2006
8763	Drywood	Canadian Gas & Electric	10000	6000	13	01-01-1980	12-31-2025
8770	Fort Nelson	TransAlta	10000	45000	13	01-01-2000	12-31-2025
8784	Red Earth Creek Area	Columbia Power Systems	9500	4000	13	01-01-1980	12-31-2004
8789	Springfield ICs	Springfield Utility Board	10000	26700	1	04-01-2001	12-31-2011
8800	Calgary Energy Centre	Calpine	8500	250000	13	12-01-2002	12-31-2013
8804	Cavalier Power Station	PanCanadian	9500	106000	13	09-01-2001	12-31-2010
8811	Drywood Exp	Canadian Gas & Electric	10000	7000	13	09-01-2001	12-31-2025
8813	Elmworth Area	Northstone Power Corp	9500	15000	13	10-01-2001	12-31-2004
8815	Gillette Upgrade	Black Hills	10000	10000	7	06-01-2001	12-31-2009
8834	Petitt Industrial Park	California NEO	11000	49000	2	06-01-2001	12-31-2011
8839	Red Deer (A)	API Grain Processors	12000	3500	13	06-01-2001	12-31-2007
8840	Red Deer (B)	Collicutt Hanover Servcies	12000	2000	13	10-01-2001	12-31-2007
8847	Sturgeon Addition	ATCO	10000	92000	13	12-01-2001	12-31-2025
8851	Taber area	Maxim Energy Corp	10000	8500	13	12-01-2001	12-31-2025
8853	University of CA Riverside	Southern States Power Co Inc	10000	6000	3	08-01-2001	12-31-2028
8854	Valleyview (AB)	ATCO	9000	92000	13	11-01-2001	12-31-2011
8859	Sturgeon	ATCO	10000	18000	13	01-01-1980	12-31-2025
8956	Cipres 1-2	Comision Federal de Electricidad	10000	54860	18	01-01-1980	12-31-2011
8957	Mexicali 1	Comision Federal de Electricidad	10000	31200	18	01-01-1980	12-31-2004
8958	Mexicali 2-3	Comision Federal de Electricidad	10000	41300	18	01-01-1980	12-31-2005
8959	Pdte Juarez 1-6	Comision Federal de Electricidad	9500	620000	18	01-01-1980	12-31-2012
8960	Pdte Juarez GT1-2	Comision Federal de Electricidad	10000	63220	18	01-01-1980	12-31-2011
9003	Grays Harbor Co PUD ICs	Grays Harbor PUD	10000	12000	1	07-01-2001	12-31-2009
9004	Gunkel Orchards	Gunkel Orchards	10000	3200	1	05-01-2001	12-31-2028
9010	Titan	Titan	10000	15000	1	07-01-2001	12-31-2011
9011	Gillette GT 1	Black Hills	8600	40000	7	07-01-2000	12-31-2011
9012	Gillette GT 2	Black Hills	8600	40000	7	05-01-2001	12-31-2007
9015	Valmont Plant Expansion (Boulder)	Black Hills	10000	40000	8	07-01-2001	12-31-2013
9024	Wyodak Expansion	Black Hills	11680	40000	7	05-01-2001	12-31-2009
9153	BHG Gas Turbine #2	Black Hills Corporation	10000	34000	7	06-01-2001	12-31-2008
9154	Bountiful City 1A	Bountiful City City of	11000	5100	11	06-01-2001	12-31-2007
9348	OR SBC Wind 03	N/A	0	30000	1	12-31-2003	12-31-2049
9349	OR SBC Wind 04	N/A	0	30000	1	12-31-2004	12-31-2049
9350	OR SBC Wind 05	N/A	0	30000	1	12-31-2005	12-31-2049
9351	OR SBC Wind 06	N/A	0	30000	1	12-31-2006	12-31-2049
9352	OR SBC Wind 07	N/A	0	30000	1	12-31-2007	12-31-2049

Resource #	Name	Utility	Heat Rate	Capacity (kW)	Load Area	Begin Date	Retire Date
9353	OR SBC Wind 08	N/A	0	30000	1	12-31-2008	12-31-2049
9354	OR SBC Wind 09	N/A	0	30000	1	12-31-2009	12-31-2049
9355	OR SBC Wind 10	N/A	0	30000	1	12-31-2010	12-31-2049
9356	OR SBC Wind 11	N/A	0	30000	1	12-31-2011	12-31-2049
9357	OR SBC Wind 12	N/A	0	30000	1	12-31-2012	12-31-2049
9358	CAN SBC Wind 03	N/A	0	90000	2	12-31-2003	12-31-2049
9359	CAN SBC Wind 04	N/A	0	90000	2	12-31-2004	12-31-2049
9360	CAN SBC Wind 05	N/A	0	90000	2	12-31-2005	12-31-2049
9361	CAN SBC Wind 06	N/A	0	90000	2	12-31-2006	12-31-2049
9362	CAN SBC Wind 07	N/A	0	90000	2	12-31-2007	12-31-2049
9363	CAN SBC Wind 08	N/A	0	90000	2	12-31-2008	12-31-2049
9364	CAN SBC Wind 09	N/A	0	90000	2	12-31-2009	12-31-2049
9365	CAN SBC Wind 10	N/A	0	90000	2	12-31-2010	12-31-2049
9366	CAN SBC Wind 11	N/A	0	90000	2	12-31-2011	12-31-2049
9367	CAN SBC Wind 12	N/A	0	90000	2	12-31-2012	12-31-2049
9368	CAS SBC Wind 03	N/A	0	90000	3	12-31-2003	12-31-2049
9369	CAS SBC Wind 04	N/A	0	90000	3	12-31-2004	12-31-2049
9370	CAS SBC Wind 05	N/A	0	90000	3	12-31-2005	12-31-2049
9371	CAS SBC Wind 06	N/A	0	90000	3	12-31-2006	12-31-2049
9372	CAS SBC Wind 07	N/A	0	90000	3	12-31-2007	12-31-2049
9373	CAS SBC Wind 08	N/A	0	90000	3	12-31-2008	12-31-2049
9374	CAS SBC Wind 09	N/A	0	90000	3	12-31-2009	12-31-2049
9375	CAS SBC Wind 10	N/A	0	90000	3	12-31-2010	12-31-2049
9376	CAS SBC Wind 11	N/A	0	90000	3	12-31-2011	12-31-2049
9377	CAS SBC Wind 12	N/A	0	90000	3	12-31-2012	12-31-2049
9378	MT SBC Wind 03	N/A	0	3000	6	12-31-2003	12-31-2049
9379	MT SBC Wind 04	N/A	0	3000	6	12-31-2004	12-31-2049
9380	MT SBC Wind 05	N/A	0	3000	6	12-31-2005	12-31-2049
9381	MT SBC Wind 06	N/A	0	3000	6	12-31-2006	12-31-2049
9382	MT SBC Wind 07	N/A	0	3000	6	12-31-2007	12-31-2049
9383	MT SBC Wind 08	N/A	0	3000	6	12-31-2008	12-31-2049
9384	MT SBC Wind 09	N/A	0	3000	6	12-31-2009	12-31-2049
9385	MT SBC Wind 10	N/A	0	3000	6	12-31-2010	12-31-2049
9386	MT SBC Wind 11	N/A	0	3000	6	12-31-2011	12-31-2049
9387	MT SBC Wind 12	N/A	0	3000	6	12-31-2012	12-31-2049
9388	NM SBC Wind 03	N/A	0	12000	9	12-31-2003	12-31-2049
9389	NM SBC Wind 04	N/A	0	12000	9	12-31-2004	12-31-2049
9390	NM SBC Wind 05	N/A	0	12000	9	12-31-2005	12-31-2049
9391	NM SBC Wind 06	N/A	0	12000	9	12-31-2006	12-31-2049
9392	NM SBC Wind 07	N/A	0	12000	9	12-31-2007	12-31-2049
9393	NM SBC Wind 08	N/A	0	12000	9	12-31-2008	12-31-2049
9394	NM SBC Wind 09	N/A	0	12000	9	12-31-2009	12-31-2049
9395	NM SBC Wind 10	N/A	0	12000	9	12-31-2010	12-31-2049
9396	NM SBC Wind 11	N/A	0	12000	9	12-31-2011	12-31-2049
9397	NM SBC Wind 12	N/A	0	12000	9	12-31-2012	12-31-2049
9398	AZ SBC Wind 03	N/A	0	70000	10	12-31-2003	12-31-2049
9399	AZ SBC Wind 04	N/A	0	70000	10	12-31-2004	12-31-2049

Resource #	Name	Utility	Heat Rate	Capacity (kW)	Load Area	Begin Date	Retire Date
9400	AZ SBC Wind 05	N/A	0	70000	10	12-31-2005	12-31-2049
9401	AZ SBC Wind 06	N/A	0	70000	10	12-31-2006	12-31-2049
9402	AZ SBC Wind 07	N/A	0	70000	10	12-31-2007	12-31-2049
9403	AZ SBC Wind 08	N/A	0	70000	10	12-31-2008	12-31-2049
9404	AZ SBC Wind 09	N/A	0	70000	10	12-31-2009	12-31-2049
9405	AZ SBC Wind 10	N/A	0	70000	10	12-31-2010	12-31-2049
9406	AZ SBC Wind 11	N/A	0	70000	10	12-31-2011	12-31-2049
9407	AZ SBC Wind 12	N/A	0	70000	10	12-31-2012	12-31-2049
AURORANewRes 1	New No 2916 Coal 400 MW	na	9426	400000	6	01-01-2010	12-31-2049
AURORANewRes 10	New No 5352 CCCT 280 MW	na	6233	280000	1	01-01-2022	12-31-2049
AURORANewRes 100	New No 5727 CCCT 280 MW	na	6619	280000	3	01-01-2012	12-31-2049
AURORANewRes 101	New No 5729 CCCT 280 MW	na	6619	280000	3	01-01-2012	12-31-2049
AURORANewRes 102	New No 5730 CCCT 280 MW	na	6619	280000	3	01-01-2012	12-31-2049
AURORANewRes 103	New No 5731 CCCT 280 MW	na	6619	280000	3	01-01-2012	12-31-2049
AURORANewRes 104	New No 5732 CCCT 280 MW	na	6619	280000	3	01-01-2012	12-31-2049
AURORANewRes 105	New No 5733 CCCT 280 MW	na	6619	280000	3	01-01-2012	12-31-2049
AURORANewRes 106	New No 5734 CCCT 280 MW	na	6619	280000	3	01-01-2012	12-31-2049
AURORANewRes 107	New No 5735 CCCT 280 MW	na	6619	280000	3	01-01-2012	12-31-2049
AURORANewRes 108	New No 5736 CCCT 280 MW	na	6580	280000	3	01-01-2013	12-31-2049
AURORANewRes 109	New No 5737 CCCT 280 MW	na	6580	280000	3	01-01-2013	12-31-2049
AURORANewRes 11	New No 5353 CCCT 280 MW	na	6233	280000	1	01-01-2022	12-31-2049
AURORANewRes 110	New No 5738 CCCT 280 MW	na	6580	280000	3	01-01-2013	12-31-2049
AURORANewRes 111	New No 5739 CCCT 280 MW	na	6580	280000	3	01-01-2013	12-31-2049
AURORANewRes 112	New No 5742 CCCT 280 MW	na	6580	280000	3	01-01-2013	12-31-2049
AURORANewRes 113	New No 5743 CCCT 280 MW	na	6580	280000	3	01-01-2013	12-31-2049
AURORANewRes 114	New No 5745 CCCT 280 MW	na	6580	280000	3	01-01-2013	12-31-2049
AURORANewRes 115	New No 5746 CCCT 280 MW	na	6540	280000	3	01-01-2014	12-31-2049
AURORANewRes 116	New No 5747 CCCT 280 MW	na	6540	280000	3	01-01-2014	12-31-2049
AURORANewRes 117	New No 5748 CCCT 280 MW	na	6540	280000	3	01-01-2014	12-31-2049
AURORANewRes 118	New No 5749 CCCT 280 MW	na	6540	280000	3	01-01-2014	12-31-2049
AURORANewRes 119	New No 5753 CCCT 280 MW	na	6540	280000	3	01-01-2014	12-31-2049
AURORANewRes 12	New No 5368 CCCT 280 MW	na	6158	280000	1	01-01-2024	12-31-2049
AURORANewRes 120	New No 5754 CCCT 280 MW	na	6540	280000	3	01-01-2014	12-31-2049
AURORANewRes 121	New No 5755 CCCT 280 MW	na	6540	280000	3	01-01-2014	12-31-2049
AURORANewRes 122	New No 5756 CCCT 280 MW	na	6501	280000	3	01-01-2015	12-31-2049
AURORANewRes 123	New No 5757 CCCT 280 MW	na	6501	280000	3	01-01-2015	12-31-2049
AURORANewRes 124	New No 5758 CCCT 280 MW	na	6501	280000	3	01-01-2015	12-31-2049
AURORANewRes 125	New No 5759 CCCT 280 MW	na	6501	280000	3	01-01-2015	12-31-2049
AURORANewRes 126	New No 5766 CCCT 280 MW	na	6462	280000	3	01-01-2016	12-31-2049
AURORANewRes 127	New No 5767 CCCT 280 MW	na	6462	280000	3	01-01-2016	12-31-2049
AURORANewRes 128	New No 5768 CCCT 280 MW	na	6462	280000	3	01-01-2016	12-31-2049
AURORANewRes 129	New No 5772 CCCT 280 MW	na	6462	280000	3	01-01-2016	12-31-2049
AURORANewRes 13	New No 5378 CCCT 280 MW	na	6121	280000	1	01-01-2025	12-31-2049
AURORANewRes 130	New No 5774 CCCT 280 MW	na	6462	280000	3	01-01-2016	12-31-2049
AURORANewRes 131	New No 5776 CCCT 280 MW	na	6423	280000	3	01-01-2017	12-31-2049
AURORANewRes 132	New No 5777 CCCT 280 MW	na	6423	280000	3	01-01-2017	12-31-2049
AURORANewRes 133	New No 5778 CCCT 280 MW	na	6423	280000	3	01-01-2017	12-31-2049

Resource #	Name	Utility	Heat Rate	Capacity (kW)	Load Area	Begin Date	Retire Date
AURORANewRes 134	New No 5779 CCCT 280 MW	na	6423	280000	3	01-01-2017	12-31-2049
AURORANewRes 135	New No 5780 CCCT 280 MW	na	6423	280000	3	01-01-2017	12-31-2049
AURORANewRes 136	New No 5786 CCCT 280 MW	na	6385	280000	3	01-01-2018	12-31-2049
AURORANewRes 137	New No 5787 CCCT 280 MW	na	6385	280000	3	01-01-2018	12-31-2049
AURORANewRes 138	New No 5788 CCCT 280 MW	na	6385	280000	3	01-01-2018	12-31-2049
AURORANewRes 139	New No 5789 CCCT 280 MW	na	6385	280000	3	01-01-2018	12-31-2049
AURORANewRes 14	New No 5380 CCCT 280 MW	na	6121	280000	1	01-01-2025	12-31-2049
AURORANewRes 140	New No 5790 CCCT 280 MW	na	6385	280000	3	01-01-2018	12-31-2049
AURORANewRes 141	New No 5798 CCCT 280 MW	na	6346	280000	3	01-01-2019	12-31-2049
AURORANewRes 142	New No 5799 CCCT 280 MW	na	6346	280000	3	01-01-2019	12-31-2049
AURORANewRes 143	New No 5800 CCCT 280 MW	na	6346	280000	3	01-01-2019	12-31-2049
AURORANewRes 144	New No 5801 CCCT 280 MW	na	6346	280000	3	01-01-2019	12-31-2049
AURORANewRes 145	New No 5804 CCCT 280 MW	na	6346	280000	3	01-01-2019	12-31-2049
AURORANewRes 146	New No 5806 CCCT 280 MW	na	6308	280000	3	01-01-2020	12-31-2049
AURORANewRes 147	New No 5807 CCCT 280 MW	na	6308	280000	3	01-01-2020	12-31-2049
AURORANewRes 148	New No 5808 CCCT 280 MW	na	6308	280000	3	01-01-2020	12-31-2049
AURORANewRes 149	New No 5809 CCCT 280 MW	na	6308	280000	3	01-01-2020	12-31-2049
AURORANewRes 15	New No 5386 CCCT 280 MW	na	6085	280000	1	01-01-2026	12-31-2049
AURORANewRes 150	New No 5810 CCCT 280 MW	na	6308	280000	3	01-01-2020	12-31-2049
AURORANewRes 151	New No 5811 CCCT 280 MW	na	6308	280000	3	01-01-2020	12-31-2049
AURORANewRes 152	New No 5812 CCCT 280 MW	na	6308	280000	3	01-01-2020	12-31-2049
AURORANewRes 153	New No 5813 CCCT 280 MW	na	6308	280000	3	01-01-2020	12-31-2049
AURORANewRes 154	New No 5814 CCCT 280 MW	na	6308	280000	3	01-01-2020	12-31-2049
AURORANewRes 155	New No 5815 CCCT 280 MW	na	6308	280000	3	01-01-2020	12-31-2049
AURORANewRes 156	New No 5820 CCCT 280 MW	na	6270	280000	3	01-01-2021	12-31-2049
AURORANewRes 157	New No 5821 CCCT 280 MW	na	6270	280000	3	01-01-2021	12-31-2049
AURORANewRes 158	New No 5822 CCCT 280 MW	na	6270	280000	3	01-01-2021	12-31-2049
AURORANewRes 159	New No 5823 CCCT 280 MW	na	6270	280000	3	01-01-2021	12-31-2049
AURORANewRes 16	New No 5399 CCCT 280 MW	na	6048	280000	1	01-01-2027	12-31-2049
AURORANewRes 160	New No 5824 CCCT 280 MW	na	6270	280000	3	01-01-2021	12-31-2049
AURORANewRes 161	New No 5826 CCCT 280 MW	na	6233	280000	3	01-01-2022	12-31-2049
AURORANewRes 162	New No 5827 CCCT 280 MW	na	6233	280000	3	01-01-2022	12-31-2049
AURORANewRes 163	New No 5829 CCCT 280 MW	na	6233	280000	3	01-01-2022	12-31-2049
AURORANewRes 164	New No 5830 CCCT 280 MW	na	6233	280000	3	01-01-2022	12-31-2049
AURORANewRes 165	New No 5831 CCCT 280 MW	na	6233	280000	3	01-01-2022	12-31-2049
AURORANewRes 166	New No 5832 CCCT 280 MW	na	6233	280000	3	01-01-2022	12-31-2049
AURORANewRes 167	New No 5833 CCCT 280 MW	na	6233	280000	3	01-01-2022	12-31-2049
AURORANewRes 168	New No 5835 CCCT 280 MW	na	6233	280000	3	01-01-2022	12-31-2049
AURORANewRes 169	New No 5845 CCCT 280 MW	na	6195	280000	3	01-01-2023	12-31-2049
AURORANewRes 17	New No 5400 CCCT 280 MW	na	6048	280000	1	01-01-2027	12-31-2049
AURORANewRes 170	New No 5846 CCCT 280 MW	na	6158	280000	3	01-01-2024	12-31-2049
AURORANewRes 171	New No 5847 CCCT 280 MW	na	6158	280000	3	01-01-2024	12-31-2049
AURORANewRes 172	New No 5848 CCCT 280 MW	na	6158	280000	3	01-01-2024	12-31-2049
AURORANewRes 173	New No 5850 CCCT 280 MW	na	6158	280000	3	01-01-2024	12-31-2049
AURORANewRes 174	New No 5856 CCCT 280 MW	na	6121	280000	3	01-01-2025	12-31-2049
AURORANewRes 175	New No 5860 CCCT 280 MW	na	6121	280000	3	01-01-2025	12-31-2049
AURORANewRes 176	New No 5862 CCCT 280 MW	na	6121	280000	3	01-01-2025	12-31-2049

Resource #	Name	Utility	Heat Rate	Capacity (kW)	Load Area	Begin Date	Retire Date
AURORANewRes 177	New No 5863 CCCT 280 MW	na	6121	280000	3	01-01-2025	12-31-2049
AURORANewRes 178	New No 5864 CCCT 280 MW	na	6121	280000	3	01-01-2025	12-31-2049
AURORANewRes 179	New No 5865 CCCT 280 MW	na	6121	280000	3	01-01-2025	12-31-2049
AURORANewRes 18	New No 5411 CCCT 280 MW	na	6012	280000	1	01-01-2028	12-31-2049
AURORANewRes 180	New No 5866 CCCT 280 MW	na	6085	280000	3	01-01-2026	12-31-2049
AURORANewRes 181	New No 5867 CCCT 280 MW	na	6085	280000	3	01-01-2026	12-31-2049
AURORANewRes 182	New No 5868 CCCT 280 MW	na	6085	280000	3	01-01-2026	12-31-2049
AURORANewRes 183	New No 5869 CCCT 280 MW	na	6085	280000	3	01-01-2026	12-31-2049
AURORANewRes 184	New No 5870 CCCT 280 MW	na	6085	280000	3	01-01-2026	12-31-2049
AURORANewRes 185	New No 5871 CCCT 280 MW	na	6085	280000	3	01-01-2026	12-31-2049
AURORANewRes 186	New No 5872 CCCT 280 MW	na	6085	280000	3	01-01-2026	12-31-2049
AURORANewRes 187	New No 5873 CCCT 280 MW	na	6085	280000	3	01-01-2026	12-31-2049
AURORANewRes 188	New No 5874 CCCT 280 MW	na	6085	280000	3	01-01-2026	12-31-2049
AURORANewRes 189	New No 5876 CCCT 280 MW	na	6048	280000	3	01-01-2027	12-31-2049
AURORANewRes 19	New No 5413 CCCT 280 MW	na	6012	280000	1	01-01-2028	12-31-2049
AURORANewRes 190	New No 5877 CCCT 280 MW	na	6048	280000	3	01-01-2027	12-31-2049
AURORANewRes 191	New No 5878 CCCT 280 MW	na	6048	280000	3	01-01-2027	12-31-2049
AURORANewRes 192	New No 5879 CCCT 280 MW	na	6048	280000	3	01-01-2027	12-31-2049
AURORANewRes 193	New No 5880 CCCT 280 MW	na	6048	280000	3	01-01-2027	12-31-2049
AURORANewRes 194	New No 5882 CCCT 280 MW	na	6048	280000	3	01-01-2027	12-31-2049
AURORANewRes 195	New No 5885 CCCT 280 MW	na	6048	280000	3	01-01-2027	12-31-2049
AURORANewRes 196	New No 5887 CCCT 280 MW	na	6012	280000	3	01-01-2028	12-31-2049
AURORANewRes 197	New No 5889 CCCT 280 MW	na	6012	280000	3	01-01-2028	12-31-2049
AURORANewRes 198	New No 5892 CCCT 280 MW	na	6012	280000	3	01-01-2028	12-31-2049
AURORANewRes 199	New No 5893 CCCT 280 MW	na	6012	280000	3	01-01-2028	12-31-2049
AURORANewRes 2	New No 2918 Coal 400 MW	na	9426	400000	6	01-01-2010	12-31-2049
AURORANewRes 20	New No 5415 CCCT 280 MW	na	6012	280000	1	01-01-2028	12-31-2049
AURORANewRes 200	New No 5894 CCCT 280 MW	na	6012	280000	3	01-01-2028	12-31-2049
AURORANewRes 201	New No 5895 CCCT 280 MW	na	6012	280000	3	01-01-2028	12-31-2049
AURORANewRes 202	New No 5919 CCCT 280 MW	na	6822	280000	4	01-01-2007	12-31-2049
AURORANewRes 203	New No 5942 CCCT 280 MW	na	6740	280000	4	01-01-2009	12-31-2049
AURORANewRes 204	New No 5952 CCCT 280 MW	na	6700	280000	4	01-01-2010	12-31-2049
AURORANewRes 205	New No 5959 CCCT 280 MW	na	6659	280000	4	01-01-2011	12-31-2049
AURORANewRes 206	New No 5974 CCCT 280 MW	na	6619	280000	4	01-01-2012	12-31-2049
AURORANewRes 207	New No 5982 CCCT 280 MW	na	6580	280000	4	01-01-2013	12-31-2049
AURORANewRes 208	New No 5989 CCCT 280 MW	na	6540	280000	4	01-01-2014	12-31-2049
AURORANewRes 209	New No 5997 CCCT 280 MW	na	6501	280000	4	01-01-2015	12-31-2049
AURORANewRes 21	New No 5477 CCCT 280 MW	na	6659	280000	2	01-01-2011	12-31-2049
AURORANewRes 210	New No 6009 CCCT 280 MW	na	6462	280000	4	01-01-2016	12-31-2049
AURORANewRes 211	New No 6027 CCCT 280 MW	na	6385	280000	4	01-01-2018	12-31-2049
AURORANewRes 212	New No 6042 CCCT 280 MW	na	6346	280000	4	01-01-2019	12-31-2049
AURORANewRes 213	New No 6049 CCCT 280 MW	na	6308	280000	4	01-01-2020	12-31-2049
AURORANewRes 214	New No 6058 CCCT 280 MW	na	6270	280000	4	01-01-2021	12-31-2049
AURORANewRes 215	New No 6078 CCCT 280 MW	na	6195	280000	4	01-01-2023	12-31-2049
AURORANewRes 216	New No 6080 CCCT 280 MW	na	6195	280000	4	01-01-2023	12-31-2049
AURORANewRes 217	New No 6091 CCCT 280 MW	na	6158	280000	4	01-01-2024	12-31-2049
AURORANewRes 218	New No 6094 CCCT 280 MW	na	6158	280000	4	01-01-2024	12-31-2049

Resource #	Name	Utility	Heat Rate	Capacity (kW)	Load Area	Begin Date	Retire Date
AURORANewRes 219	New No 6099 CCCT 280 MW	na	6121	280000	4	01-01-2025	12-31-2049
AURORANewRes 22	New No 5478 CCCT 280 MW	na	6659	280000	2	01-01-2011	12-31-2049
AURORANewRes 220	New No 6103 CCCT 280 MW	na	6121	280000	4	01-01-2025	12-31-2049
AURORANewRes 221	New No 6119 CCCT 280 MW	na	6048	280000	4	01-01-2027	12-31-2049
AURORANewRes 222	New No 6120 CCCT 280 MW	na	6048	280000	4	01-01-2027	12-31-2049
AURORANewRes 223	New No 6134 CCCT 280 MW	na	6012	280000	4	01-01-2028	12-31-2049
AURORANewRes 224	New No 6212 CCCT 280 MW	na	6619	280000	5	01-01-2012	12-31-2049
AURORANewRes 225	New No 6228 CCCT 280 MW	na	6540	280000	5	01-01-2014	12-31-2049
AURORANewRes 226	New No 6229 CCCT 280 MW	na	6540	280000	5	01-01-2014	12-31-2049
AURORANewRes 227	New No 6232 CCCT 280 MW	na	6540	280000	5	01-01-2014	12-31-2049
AURORANewRes 228	New No 6243 CCCT 280 MW	na	6501	280000	5	01-01-2015	12-31-2049
AURORANewRes 229	New No 6249 CCCT 280 MW	na	6462	280000	5	01-01-2016	12-31-2049
AURORANewRes 23	New No 5479 CCCT 280 MW	na	6659	280000	2	01-01-2011	12-31-2049
AURORANewRes 230	New No 6250 CCCT 280 MW	na	6462	280000	5	01-01-2016	12-31-2049
AURORANewRes 231	New No 6297 CCCT 280 MW	na	6270	280000	5	01-01-2021	12-31-2049
AURORANewRes 232	New No 6308 CCCT 280 MW	na	6233	280000	5	01-01-2022	12-31-2049
AURORANewRes 233	New No 6319 CCCT 280 MW	na	6195	280000	5	01-01-2023	12-31-2049
AURORANewRes 234	New No 6331 CCCT 280 MW	na	6158	280000	5	01-01-2024	12-31-2049
AURORANewRes 235	New No 6343 CCCT 280 MW	na	6121	280000	5	01-01-2025	12-31-2049
AURORANewRes 236	New No 6349 CCCT 280 MW	na	6085	280000	5	01-01-2026	12-31-2049
AURORANewRes 237	New No 6352 CCCT 280 MW	na	6085	280000	5	01-01-2026	12-31-2049
AURORANewRes 238	New No 6357 CCCT 280 MW	na	6048	280000	5	01-01-2027	12-31-2049
AURORANewRes 239	New No 6358 CCCT 280 MW	na	6048	280000	5	01-01-2027	12-31-2049
AURORANewRes 24	New No 5486 CCCT 280 MW	na	6619	280000	2	01-01-2012	12-31-2049
AURORANewRes 240	New No 6465 CCCT 280 MW	na	6580	280000	6	01-01-2013	12-31-2049
AURORANewRes 241	New No 6490 CCCT 280 MW	na	6462	280000	6	01-01-2016	12-31-2049
AURORANewRes 242	New No 6534 CCCT 280 MW	na	6308	280000	6	01-01-2020	12-31-2049
AURORANewRes 243	New No 6592 CCCT 280 MW	na	6085	280000	6	01-01-2026	12-31-2049
AURORANewRes 244	New No 6599 CCCT 280 MW	na	6048	280000	6	01-01-2027	12-31-2049
AURORANewRes 245	New No 6606 CCCT 280 MW	na	6012	280000	6	01-01-2028	12-31-2049
AURORANewRes 246	New No 6607 CCCT 280 MW	na	6012	280000	6	01-01-2028	12-31-2049
AURORANewRes 247	New No 6741 CCCT 280 MW	na	6423	280000	7	01-01-2017	12-31-2049
AURORANewRes 248	New No 6836 CCCT 280 MW	na	6048	280000	7	01-01-2027	12-31-2049
AURORANewRes 249	New No 6848 CCCT 280 MW	na	6012	280000	7	01-01-2028	12-31-2049
AURORANewRes 25	New No 5489 CCCT 280 MW	na	6619	280000	2	01-01-2012	12-31-2049
AURORANewRes 250	New No 6849 CCCT 280 MW	na	6012	280000	7	01-01-2028	12-31-2049
AURORANewRes 251	New No 6850 CCCT 280 MW	na	6012	280000	7	01-01-2028	12-31-2049
AURORANewRes 252	New No 6851 CCCT 280 MW	na	6012	280000	7	01-01-2028	12-31-2049
AURORANewRes 253	New No 6852 CCCT 280 MW	na	6012	280000	7	01-01-2028	12-31-2049
AURORANewRes 254	New No 6961 CCCT 280 MW	na	6501	280000	8	01-01-2015	12-31-2049
AURORANewRes 255	New No 6962 CCCT 280 MW	na	6501	280000	8	01-01-2015	12-31-2049
AURORANewRes 256	New No 6972 CCCT 280 MW	na	6462	280000	8	01-01-2016	12-31-2049
AURORANewRes 257	New No 6992 CCCT 280 MW	na	6385	280000	8	01-01-2018	12-31-2049
AURORANewRes 258	New No 7005 CCCT 280 MW	na	6346	280000	8	01-01-2019	12-31-2049
AURORANewRes 259	New No 7012 CCCT 280 MW	na	6308	280000	8	01-01-2020	12-31-2049
AURORANewRes 26	New No 5490 CCCT 280 MW	na	6619	280000	2	01-01-2012	12-31-2049
AURORANewRes 260	New No 7039 CCCT 280 MW	na	6195	280000	8	01-01-2023	12-31-2049

Resource #	Name	Utility	Heat Rate	Capacity (kW)	Load Area	Begin Date	Retire Date
AURORANewRes 261	New No 7045 CCCT 280 MW	na	6195	280000	8	01-01-2023	12-31-2049
AURORANewRes 262	New No 7052 CCCT 280 MW	na	6158	280000	8	01-01-2024	12-31-2049
AURORANewRes 263	New No 7067 CCCT 280 MW	na	6085	280000	8	01-01-2026	12-31-2049
AURORANewRes 264	New No 7079 CCCT 280 MW	na	6048	280000	8	01-01-2027	12-31-2049
AURORANewRes 265	New No 7082 CCCT 280 MW	na	6048	280000	8	01-01-2027	12-31-2049
AURORANewRes 266	New No 7085 CCCT 280 MW	na	6048	280000	8	01-01-2027	12-31-2049
AURORANewRes 267	New No 7086 CCCT 280 MW	na	6012	280000	8	01-01-2028	12-31-2049
AURORANewRes 268	New No 7088 CCCT 280 MW	na	6012	280000	8	01-01-2028	12-31-2049
AURORANewRes 269	New No 7089 CCCT 280 MW	na	6012	280000	8	01-01-2028	12-31-2049
AURORANewRes 27	New No 5491 CCCT 280 MW	na	6619	280000	2	01-01-2012	12-31-2049
AURORANewRes 270	New No 7090 CCCT 280 MW	na	6012	280000	8	01-01-2028	12-31-2049
AURORANewRes 271	New No 7091 CCCT 280 MW	na	6012	280000	8	01-01-2028	12-31-2049
AURORANewRes 272	New No 7093 CCCT 280 MW	na	6012	280000	8	01-01-2028	12-31-2049
AURORANewRes 273	New No 7094 CCCT 280 MW	na	6012	280000	8	01-01-2028	12-31-2049
AURORANewRes 274	New No 7177 CCCT 280 MW	na	6580	280000	9	01-01-2013	12-31-2049
AURORANewRes 275	New No 7178 CCCT 280 MW	na	6580	280000	9	01-01-2013	12-31-2049
AURORANewRes 276	New No 7181 CCCT 280 MW	na	6580	280000	9	01-01-2013	12-31-2049
AURORANewRes 277	New No 7193 CCCT 280 MW	na	6540	280000	9	01-01-2014	12-31-2049
AURORANewRes 278	New No 7194 CCCT 280 MW	na	6540	280000	9	01-01-2014	12-31-2049
AURORANewRes 279	New No 7197 CCCT 280 MW	na	6501	280000	9	01-01-2015	12-31-2049
AURORANewRes 28	New No 5492 CCCT 280 MW	na	6619	280000	2	01-01-2012	12-31-2049
AURORANewRes 280	New No 7199 CCCT 280 MW	na	6501	280000	9	01-01-2015	12-31-2049
AURORANewRes 281	New No 7210 CCCT 280 MW	na	6462	280000	9	01-01-2016	12-31-2049
AURORANewRes 282	New No 7219 CCCT 280 MW	na	6423	280000	9	01-01-2017	12-31-2049
AURORANewRes 283	New No 7232 CCCT 280 MW	na	6385	280000	9	01-01-2018	12-31-2049
AURORANewRes 284	New No 7258 CCCT 280 MW	na	6270	280000	9	01-01-2021	12-31-2049
AURORANewRes 285	New No 7268 CCCT 280 MW	na	6233	280000	9	01-01-2022	12-31-2049
AURORANewRes 286	New No 7271 CCCT 280 MW	na	6233	280000	9	01-01-2022	12-31-2049
AURORANewRes 287	New No 7280 CCCT 280 MW	na	6195	280000	9	01-01-2023	12-31-2049
AURORANewRes 288	New No 7282 CCCT 280 MW	na	6195	280000	9	01-01-2023	12-31-2049
AURORANewRes 289	New No 7290 CCCT 280 MW	na	6158	280000	9	01-01-2024	12-31-2049
AURORANewRes 29	New No 5494 CCCT 280 MW	na	6619	280000	2	01-01-2012	12-31-2049
AURORANewRes 290	New No 7292 CCCT 280 MW	na	6158	280000	9	01-01-2024	12-31-2049
AURORANewRes 291	New No 7299 CCCT 280 MW	na	6121	280000	9	01-01-2025	12-31-2049
AURORANewRes 292	New No 7301 CCCT 280 MW	na	6121	280000	9	01-01-2025	12-31-2049
AURORANewRes 293	New No 7302 CCCT 280 MW	na	6121	280000	9	01-01-2025	12-31-2049
AURORANewRes 294	New No 7309 CCCT 280 MW	na	6085	280000	9	01-01-2026	12-31-2049
AURORANewRes 295	New No 7316 CCCT 280 MW	na	6048	280000	9	01-01-2027	12-31-2049
AURORANewRes 296	New No 7318 CCCT 280 MW	na	6048	280000	9	01-01-2027	12-31-2049
AURORANewRes 297	New No 7324 CCCT 280 MW	na	6048	280000	9	01-01-2027	12-31-2049
AURORANewRes 298	New No 7332 CCCT 280 MW	na	6012	280000	9	01-01-2028	12-31-2049
AURORANewRes 299	New No 7334 CCCT 280 MW	na	6012	280000	9	01-01-2028	12-31-2049
AURORANewRes 3	New No 3142 Coal 400 MW	na	9451	400000	7	01-01-2009	12-31-2049
AURORANewRes 30	New No 5495 CCCT 280 MW	na	6619	280000	2	01-01-2012	12-31-2049
AURORANewRes 300	New No 7335 CCCT 280 MW	na	6012	280000	9	01-01-2028	12-31-2049
AURORANewRes 301	New No 7419 CCCT 280 MW	na	6580	280000	10	01-01-2013	12-31-2049
AURORANewRes 302	New No 7432 CCCT 280 MW	na	6540	280000	10	01-01-2014	12-31-2049

Resource #	Name	Utility	Heat Rate	Capacity (kW)	Load Area	Begin Date	Retire Date
AURORANewRes 303	New No 7438 CCCT 280 MW	na	6501	280000	10	01-01-2015	12-31-2049
AURORANewRes 304	New No 7441 CCCT 280 MW	na	6501	280000	10	01-01-2015	12-31-2049
AURORANewRes 305	New No 7459 CCCT 280 MW	na	6423	280000	10	01-01-2017	12-31-2049
AURORANewRes 306	New No 7460 CCCT 280 MW	na	6423	280000	10	01-01-2017	12-31-2049
AURORANewRes 307	New No 7506 CCCT 280 MW	na	6233	280000	10	01-01-2022	12-31-2049
AURORANewRes 308	New No 7507 CCCT 280 MW	na	6233	280000	10	01-01-2022	12-31-2049
AURORANewRes 309	New No 7513 CCCT 280 MW	na	6233	280000	10	01-01-2022	12-31-2049
AURORANewRes 31	New No 5496 CCCT 280 MW	na	6580	280000	2	01-01-2013	12-31-2049
AURORANewRes 310	New No 7514 CCCT 280 MW	na	6233	280000	10	01-01-2022	12-31-2049
AURORANewRes 311	New No 7516 CCCT 280 MW	na	6195	280000	10	01-01-2023	12-31-2049
AURORANewRes 312	New No 7519 CCCT 280 MW	na	6195	280000	10	01-01-2023	12-31-2049
AURORANewRes 313	New No 7520 CCCT 280 MW	na	6195	280000	10	01-01-2023	12-31-2049
AURORANewRes 314	New No 7522 CCCT 280 MW	na	6195	280000	10	01-01-2023	12-31-2049
AURORANewRes 315	New No 7529 CCCT 280 MW	na	6158	280000	10	01-01-2024	12-31-2049
AURORANewRes 316	New No 7530 CCCT 280 MW	na	6158	280000	10	01-01-2024	12-31-2049
AURORANewRes 317	New No 7531 CCCT 280 MW	na	6158	280000	10	01-01-2024	12-31-2049
AURORANewRes 318	New No 7532 CCCT 280 MW	na	6158	280000	10	01-01-2024	12-31-2049
AURORANewRes 319	New No 7539 CCCT 280 MW	na	6121	280000	10	01-01-2025	12-31-2049
AURORANewRes 32	New No 5497 CCCT 280 MW	na	6580	280000	2	01-01-2013	12-31-2049
AURORANewRes 320	New No 7540 CCCT 280 MW	na	6121	280000	10	01-01-2025	12-31-2049
AURORANewRes 321	New No 7549 CCCT 280 MW	na	6085	280000	10	01-01-2026	12-31-2049
AURORANewRes 322	New No 7550 CCCT 280 MW	na	6085	280000	10	01-01-2026	12-31-2049
AURORANewRes 323	New No 7551 CCCT 280 MW	na	6085	280000	10	01-01-2026	12-31-2049
AURORANewRes 324	New No 7556 CCCT 280 MW	na	6048	280000	10	01-01-2027	12-31-2049
AURORANewRes 325	New No 7563 CCCT 280 MW	na	6048	280000	10	01-01-2027	12-31-2049
AURORANewRes 326	New No 7568 CCCT 280 MW	na	6012	280000	10	01-01-2028	12-31-2049
AURORANewRes 327	New No 7570 CCCT 280 MW	na	6012	280000	10	01-01-2028	12-31-2049
AURORANewRes 328	New No 7571 CCCT 280 MW	na	6012	280000	10	01-01-2028	12-31-2049
AURORANewRes 329	New No 7572 CCCT 280 MW	na	6012	280000	10	01-01-2028	12-31-2049
AURORANewRes 33	New No 5498 CCCT 280 MW	na	6580	280000	2	01-01-2013	12-31-2049
AURORANewRes 330	New No 7573 CCCT 280 MW	na	6012	280000	10	01-01-2028	12-31-2049
AURORANewRes 331	New No 7643 CCCT 280 MW	na	6659	280000	11	01-01-2011	12-31-2049
AURORANewRes 332	New No 7661 CCCT 280 MW	na	6580	280000	11	01-01-2013	12-31-2049
AURORANewRes 333	New No 7668 CCCT 280 MW	na	6540	280000	11	01-01-2014	12-31-2049
AURORANewRes 334	New No 7669 CCCT 280 MW	na	6540	280000	11	01-01-2014	12-31-2049
AURORANewRes 335	New No 7671 CCCT 280 MW	na	6540	280000	11	01-01-2014	12-31-2049
AURORANewRes 336	New No 7676 CCCT 280 MW	na	6501	280000	11	01-01-2015	12-31-2049
AURORANewRes 337	New No 7688 CCCT 280 MW	na	6462	280000	11	01-01-2016	12-31-2049
AURORANewRes 338	New No 7740 CCCT 280 MW	na	6270	280000	11	01-01-2021	12-31-2049
AURORANewRes 339	New No 7760 CCCT 280 MW	na	6195	280000	11	01-01-2023	12-31-2049
AURORANewRes 34	New No 5499 CCCT 280 MW	na	6580	280000	2	01-01-2013	12-31-2049
AURORANewRes 340	New No 7775 CCCT 280 MW	na	6158	280000	11	01-01-2024	12-31-2049
AURORANewRes 341	New No 7787 CCCT 280 MW	na	6085	280000	11	01-01-2026	12-31-2049
AURORANewRes 342	New No 7799 CCCT 280 MW	na	6048	280000	11	01-01-2027	12-31-2049
AURORANewRes 343	New No 7802 CCCT 280 MW	na	6048	280000	11	01-01-2027	12-31-2049
AURORANewRes 344	New No 7809 CCCT 280 MW	na	6012	280000	11	01-01-2028	12-31-2049
AURORANewRes 345	New No 7811 CCCT 280 MW	na	6012	280000	11	01-01-2028	12-31-2049

Resource #	Name	Utility	Heat Rate	Capacity (kW)	Load Area	Begin Date	Retire Date
AURORANewRes 346	New No 7812 CCCT 280 MW	na	6012	280000	11	01-01-2028	12-31-2049
AURORANewRes 347	New No 7814 CCCT 280 MW	na	6012	280000	11	01-01-2028	12-31-2049
AURORANewRes 348	New No 7879 CCCT 280 MW	na	6659	280000	12	01-01-2011	12-31-2049
AURORANewRes 349	New No 7911 CCCT 280 MW	na	6540	280000	12	01-01-2014	12-31-2049
AURORANewRes 35	New No 5500 CCCT 280 MW	na	6580	280000	2	01-01-2013	12-31-2049
AURORANewRes 350	New No 7919 CCCT 280 MW	na	6501	280000	12	01-01-2015	12-31-2049
AURORANewRes 351	New No 7929 CCCT 280 MW	na	6462	280000	12	01-01-2016	12-31-2049
AURORANewRes 352	New No 7979 CCCT 280 MW	na	6270	280000	12	01-01-2021	12-31-2049
AURORANewRes 353	New No 7989 CCCT 280 MW	na	6233	280000	12	01-01-2022	12-31-2049
AURORANewRes 354	New No 8003 CCCT 280 MW	na	6195	280000	12	01-01-2023	12-31-2049
AURORANewRes 355	New No 8009 CCCT 280 MW	na	6158	280000	12	01-01-2024	12-31-2049
AURORANewRes 356	New No 8018 CCCT 280 MW	na	6121	280000	12	01-01-2025	12-31-2049
AURORANewRes 357	New No 8179 CCCT 280 MW	na	6423	280000	13	01-01-2017	12-31-2049
AURORANewRes 358	New No 8194 CCCT 280 MW	na	6385	280000	13	01-01-2018	12-31-2049
AURORANewRes 359	New No 8219 CCCT 280 MW	na	6270	280000	13	01-01-2021	12-31-2049
AURORANewRes 36	New No 5501 CCCT 280 MW	na	6580	280000	2	01-01-2013	12-31-2049
AURORANewRes 360	New No 8234 CCCT 280 MW	na	6233	280000	13	01-01-2022	12-31-2049
AURORANewRes 361	New No 8238 CCCT 280 MW	na	6195	280000	13	01-01-2023	12-31-2049
AURORANewRes 362	New No 8257 CCCT 280 MW	na	6121	280000	13	01-01-2025	12-31-2049
AURORANewRes 363	New No 8271 CCCT 280 MW	na	6085	280000	13	01-01-2026	12-31-2049
AURORANewRes 364	New No 8272 CCCT 280 MW	na	6085	280000	13	01-01-2026	12-31-2049
AURORANewRes 365	New No 8273 CCCT 280 MW	na	6085	280000	13	01-01-2026	12-31-2049
AURORANewRes 366	New No 8286 CCCT 280 MW	na	6012	280000	13	01-01-2028	12-31-2049
AURORANewRes 367	New No 8287 CCCT 280 MW	na	6012	280000	13	01-01-2028	12-31-2049
AURORANewRes 368	New No 8288 CCCT 280 MW	na	6012	280000	13	01-01-2028	12-31-2049
AURORANewRes 369	New No 8289 CCCT 280 MW	na	6012	280000	13	01-01-2028	12-31-2049
AURORANewRes 37	New No 5502 CCCT 280 MW	na	6580	280000	2	01-01-2013	12-31-2049
AURORANewRes 370	New No 8290 CCCT 280 MW	na	6012	280000	13	01-01-2028	12-31-2049
AURORANewRes 371	New No 8291 CCCT 280 MW	na	6012	280000	13	01-01-2028	12-31-2049
AURORANewRes 372	New No 8292 CCCT 280 MW	na	6012	280000	13	01-01-2028	12-31-2049
AURORANewRes 373	New No 8293 CCCT 280 MW	na	6012	280000	13	01-01-2028	12-31-2049
AURORANewRes 374	New No 8294 CCCT 280 MW	na	6012	280000	13	01-01-2028	12-31-2049
AURORANewRes 375	New No 8295 CCCT 280 MW	na	6012	280000	13	01-01-2028	12-31-2049
AURORANewRes 376	New No 8599 CCCT 280 MW	na	6659	280000	14	01-01-2011	12-31-2049
AURORANewRes 377	New No 8611 CCCT 280 MW	na	6619	280000	14	01-01-2012	12-31-2049
AURORANewRes 378	New No 8612 CCCT 280 MW	na	6619	280000	14	01-01-2012	12-31-2049
AURORANewRes 379	New No 8622 CCCT 280 MW	na	6580	280000	14	01-01-2013	12-31-2049
AURORANewRes 38	New No 5503 CCCT 280 MW	na	6580	280000	2	01-01-2013	12-31-2049
AURORANewRes 380	New No 8632 CCCT 280 MW	na	6540	280000	14	01-01-2014	12-31-2049
AURORANewRes 381	New No 8639 CCCT 280 MW	na	6501	280000	14	01-01-2015	12-31-2049
AURORANewRes 382	New No 8652 CCCT 280 MW	na	6462	280000	14	01-01-2016	12-31-2049
AURORANewRes 383	New No 8680 CCCT 280 MW	na	6346	280000	14	01-01-2019	12-31-2049
AURORANewRes 384	New No 8692 CCCT 280 MW	na	6308	280000	14	01-01-2020	12-31-2049
AURORANewRes 385	New No 8699 CCCT 280 MW	na	6270	280000	14	01-01-2021	12-31-2049
AURORANewRes 386	New No 8702 CCCT 280 MW	na	6270	280000	14	01-01-2021	12-31-2049
AURORANewRes 387	New No 8706 CCCT 280 MW	na	6233	280000	14	01-01-2022	12-31-2049
AURORANewRes 388	New No 8709 CCCT 280 MW	na	6233	280000	14	01-01-2022	12-31-2049

Resource #	Name	Utility	Heat Rate	Capacity (kW)	Load Area	Begin Date	Retire Date
AURORANewRes 389	New No 8720 CCCT 280 MW	na	6195	280000	14	01-01-2023	12-31-2049
AURORANewRes 39	New No 5505 CCCT 280 MW	na	6580	280000	2	01-01-2013	12-31-2049
AURORANewRes 390	New No 8722 CCCT 280 MW	na	6195	280000	14	01-01-2023	12-31-2049
AURORANewRes 391	New No 8729 CCCT 280 MW	na	6158	280000	14	01-01-2024	12-31-2049
AURORANewRes 392	New No 8769 CCCT 280 MW	na	6012	280000	14	01-01-2028	12-31-2049
AURORANewRes 393	New No 8772 CCCT 280 MW	na	6012	280000	14	01-01-2028	12-31-2049
AURORANewRes 394	New No 8773 CCCT 280 MW	na	6012	280000	14	01-01-2028	12-31-2049
AURORANewRes 395	New No 8914 SCCT 2x46 MW	na	8771	92000	1	01-01-2017	12-31-2049
AURORANewRes 396	New No 8926 SCCT 2x46 MW	na	8736	92000	1	01-01-2019	12-31-2049
AURORANewRes 397	New No 8929 SCCT 2x46 MW	na	8736	92000	1	01-01-2019	12-31-2049
AURORANewRes 398	New No 8930 SCCT 2x46 MW	na	8736	92000	1	01-01-2019	12-31-2049
AURORANewRes 399	New No 8932 SCCT 2x46 MW	na	8736	92000	1	01-01-2019	12-31-2049
AURORANewRes 4	New No 3161 Coal 400 MW	na	9402	400000	7	01-01-2011	12-31-2049
AURORANewRes 40	New No 5506 CCCT 280 MW	na	6540	280000	2	01-01-2014	12-31-2049
AURORANewRes 400	New No 8933 SCCT 2x46 MW	na	8736	92000	1	01-01-2019	12-31-2049
AURORANewRes 401	New No 8934 SCCT 2x46 MW	na	8736	92000	1	01-01-2019	12-31-2049
AURORANewRes 402	New No 8969 SCCT 2x46 MW	na	8692	92000	1	01-01-2023	12-31-2049
AURORANewRes 403	New No 8973 SCCT 2x46 MW	na	8692	92000	1	01-01-2023	12-31-2049
AURORANewRes 404	New No 8982 SCCT 2x46 MW	na	8683	92000	1	01-01-2024	12-31-2049
AURORANewRes 405	New No 9016 SCCT 2x46 MW	na	8675	92000	1	01-01-2028	12-31-2049
AURORANewRes 406	New No 9017 SCCT 2x46 MW	na	8675	92000	1	01-01-2028	12-31-2049
AURORANewRes 407	New No 9024 SCCT 2x46 MW	na	8675	92000	1	01-01-2028	12-31-2049
AURORANewRes 408	New No 9025 SCCT 2x46 MW	na	8675	92000	1	01-01-2028	12-31-2049
AURORANewRes 409	New No 9267 SCCT 2x46 MW	na	8675	92000	2	01-01-2028	12-31-2049
AURORANewRes 41	New No 5512 CCCT 280 MW	na	6540	280000	2	01-01-2014	12-31-2049
AURORANewRes 410	New No 9274 SCCT 2x46 MW	na	8675	92000	2	01-01-2028	12-31-2049
AURORANewRes 411	New No 9275 SCCT 2x46 MW	na	8675	92000	2	01-01-2028	12-31-2049
AURORANewRes 412	New No 9518 SCCT 2x46 MW	na	8675	92000	3	01-01-2028	12-31-2049
AURORANewRes 413	New No 9524 SCCT 2x46 MW	na	8675	92000	3	01-01-2028	12-31-2049
AURORANewRes 414	New No 11268 SCCT 2x46 MW	na	8675	92000	10	01-01-2028	12-31-2049
AURORANewRes 415	New No 11269 SCCT 2x46 MW	na	8675	92000	10	01-01-2028	12-31-2049
AURORANewRes 416	New No 11270 SCCT 2x46 MW	na	8675	92000	10	01-01-2028	12-31-2049
AURORANewRes 417	New No 12521 SCCT 2x46 MW	na	8675	92000	14	01-01-2028	12-31-2049
AURORANewRes 418	New No 12522 SCCT 2x46 MW	na	8675	92000	14	01-01-2028	12-31-2049
AURORANewRes 419	New No 12596 Wind 100 MW	na	0	100000	1	01-01-2011	12-31-2049
AURORANewRes 42	New No 5513 CCCT 280 MW	na	6540	280000	2	01-01-2014	12-31-2049
AURORANewRes 420	New No 12597 Wind 100 MW	na	0	100000	1	01-01-2011	12-31-2049
AURORANewRes 421	New No 12598 Wind 100 MW	na	0	100000	1	01-01-2011	12-31-2049
AURORANewRes 422	New No 12599 Wind 100 MW	na	0	100000	1	01-01-2011	12-31-2049
AURORANewRes 423	New No 12600 Wind 100 MW	na	0	100000	1	01-01-2011	12-31-2049
AURORANewRes 424	New No 12601 Wind 100 MW	na	0	100000	1	01-01-2011	12-31-2049
AURORANewRes 425	New No 12602 Wind 100 MW	na	0	100000	1	01-01-2011	12-31-2049
AURORANewRes 426	New No 12603 Wind 100 MW	na	0	100000	1	01-01-2011	12-31-2049
AURORANewRes 427	New No 12604 Wind 100 MW	na	0	100000	1	01-01-2011	12-31-2049
AURORANewRes 428	New No 12605 Wind 100 MW	na	0	100000	1	01-01-2011	12-31-2049
AURORANewRes 429	New No 12836 Wind 100 MW	na	0	100000	2	01-01-2010	12-31-2049
AURORANewRes 43	New No 5516 CCCT 280 MW	na	6501	280000	2	01-01-2015	12-31-2049

Resource #	Name	Utility	Heat Rate	Capacity (kW)	Load Area	Begin Date	Retire Date
AURORANewRes 430	New No 12837 Wind 100 MW	na	0	100000	2	01-01-2010	12-31-2049
AURORANewRes 431	New No 12838 Wind 100 MW	na	0	100000	2	01-01-2010	12-31-2049
AURORANewRes 432	New No 12839 Wind 100 MW	na	0	100000	2	01-01-2010	12-31-2049
AURORANewRes 433	New No 12840 Wind 100 MW	na	0	100000	2	01-01-2010	12-31-2049
AURORANewRes 434	New No 12841 Wind 100 MW	na	0	100000	2	01-01-2010	12-31-2049
AURORANewRes 435	New No 12842 Wind 100 MW	na	0	100000	2	01-01-2010	12-31-2049
AURORANewRes 436	New No 12843 Wind 100 MW	na	0	100000	2	01-01-2010	12-31-2049
AURORANewRes 437	New No 12844 Wind 100 MW	na	0	100000	2	01-01-2010	12-31-2049
AURORANewRes 438	New No 12845 Wind 100 MW	na	0	100000	2	01-01-2010	12-31-2049
AURORANewRes 439	New No 13076 Wind 100 MW	na	0	100000	3	01-01-2009	12-31-2049
AURORANewRes 44	New No 5519 CCCT 280 MW	na	6501	280000	2	01-01-2015	12-31-2049
AURORANewRes 440	New No 13077 Wind 100 MW	na	0	100000	3	01-01-2009	12-31-2049
AURORANewRes 441	New No 13078 Wind 100 MW	na	0	100000	3	01-01-2009	12-31-2049
AURORANewRes 442	New No 13079 Wind 100 MW	na	0	100000	3	01-01-2009	12-31-2049
AURORANewRes 443	New No 13080 Wind 100 MW	na	0	100000	3	01-01-2009	12-31-2049
AURORANewRes 444	New No 13081 Wind 100 MW	na	0	100000	3	01-01-2009	12-31-2049
AURORANewRes 445	New No 13082 Wind 100 MW	na	0	100000	3	01-01-2009	12-31-2049
AURORANewRes 446	New No 13083 Wind 100 MW	na	0	100000	3	01-01-2009	12-31-2049
AURORANewRes 447	New No 13084 Wind 100 MW	na	0	100000	3	01-01-2009	12-31-2049
AURORANewRes 448	New No 13085 Wind 100 MW	na	0	100000	3	01-01-2009	12-31-2049
AURORANewRes 449	New No 13319 Wind 100 MW	na	0	100000	4	01-01-2008	12-31-2049
AURORANewRes 45	New No 5520 CCCT 280 MW	na	6501	280000	2	01-01-2015	12-31-2049
AURORANewRes 450	New No 13329 Wind 100 MW	na	0	100000	4	01-01-2009	12-31-2049
AURORANewRes 451	New No 13331 Wind 100 MW	na	0	100000	4	01-01-2009	12-31-2049
AURORANewRes 452	New No 13333 Wind 100 MW	na	0	100000	4	01-01-2009	12-31-2049
AURORANewRes 453	New No 13342 Wind 100 MW	na	0	100000	4	01-01-2010	12-31-2049
AURORANewRes 454	New No 13344 Wind 100 MW	na	0	100000	4	01-01-2010	12-31-2049
AURORANewRes 455	New No 13376 Wind 100 MW	na	0	100000	4	01-01-2014	12-31-2049
AURORANewRes 456	New No 13397 Wind 100 MW	na	0	100000	4	01-01-2016	12-31-2049
AURORANewRes 457	New No 13402 Wind 100 MW	na	0	100000	4	01-01-2016	12-31-2049
AURORANewRes 458	New No 13405 Wind 100 MW	na	0	100000	4	01-01-2016	12-31-2049
AURORANewRes 459	New No 13611 Wind 100 MW	na	0	100000	5	01-01-2012	12-31-2049
AURORANewRes 46	New No 5530 CCCT 280 MW	na	6462	280000	2	01-01-2016	12-31-2049
AURORANewRes 460	New No 13618 Wind 100 MW	na	0	100000	5	01-01-2013	12-31-2049
AURORANewRes 461	New No 13620 Wind 100 MW	na	0	100000	5	01-01-2013	12-31-2049
AURORANewRes 462	New No 13622 Wind 100 MW	na	0	100000	5	01-01-2013	12-31-2049
AURORANewRes 463	New No 13623 Wind 100 MW	na	0	100000	5	01-01-2013	12-31-2049
AURORANewRes 464	New No 13624 Wind 100 MW	na	0	100000	5	01-01-2013	12-31-2049
AURORANewRes 465	New No 13625 Wind 100 MW	na	0	100000	5	01-01-2013	12-31-2049
AURORANewRes 466	New No 13652 Wind 100 MW	na	0	100000	5	01-01-2016	12-31-2049
AURORANewRes 467	New No 13656 Wind 100 MW	na	0	100000	5	01-01-2017	12-31-2049
AURORANewRes 468	New No 13674 Wind 100 MW	na	0	100000	5	01-01-2018	12-31-2049
AURORANewRes 469	New No 13816 Wind 100 MW	na	0	100000	6	01-01-2008	12-31-2049
AURORANewRes 47	New No 5531 CCCT 280 MW	na	6462	280000	2	01-01-2016	12-31-2049
AURORANewRes 470	New No 13817 Wind 100 MW	na	0	100000	6	01-01-2008	12-31-2049
AURORANewRes 471	New No 13818 Wind 100 MW	na	0	100000	6	01-01-2008	12-31-2049
AURORANewRes 472	New No 13819 Wind 100 MW	na	0	100000	6	01-01-2008	12-31-2049

Resource #	Name	Utility	Heat Rate	Capacity (kW)	Load Area	Begin Date	Retire Date
AURORANewRes 473	New No 13820 Wind 100 MW	na	0	100000	6	01-01-2008	12-31-2049
AURORANewRes 474	New No 13821 Wind 100 MW	na	0	100000	6	01-01-2008	12-31-2049
AURORANewRes 475	New No 13822 Wind 100 MW	na	0	100000	6	01-01-2008	12-31-2049
AURORANewRes 476	New No 13823 Wind 100 MW	na	0	100000	6	01-01-2008	12-31-2049
AURORANewRes 477	New No 13824 Wind 100 MW	na	0	100000	6	01-01-2008	12-31-2049
AURORANewRes 478	New No 13825 Wind 100 MW	na	0	100000	6	01-01-2008	12-31-2049
AURORANewRes 479	New No 14079 Wind 100 MW	na	0	100000	7	01-01-2009	12-31-2049
AURORANewRes 48	New No 5536 CCCT 280 MW	na	6423	280000	2	01-01-2017	12-31-2049
AURORANewRes 480	New No 14082 Wind 100 MW	na	0	100000	7	01-01-2009	12-31-2049
AURORANewRes 481	New No 14088 Wind 100 MW	na	0	100000	7	01-01-2010	12-31-2049
AURORANewRes 482	New No 14111 Wind 100 MW	na	0	100000	7	01-01-2012	12-31-2049
AURORANewRes 483	New No 14112 Wind 100 MW	na	0	100000	7	01-01-2012	12-31-2049
AURORANewRes 484	New No 14122 Wind 100 MW	na	0	100000	7	01-01-2013	12-31-2049
AURORANewRes 485	New No 14127 Wind 100 MW	na	0	100000	7	01-01-2014	12-31-2049
AURORANewRes 486	New No 14131 Wind 100 MW	na	0	100000	7	01-01-2014	12-31-2049
AURORANewRes 487	New No 14146 Wind 100 MW	na	0	100000	7	01-01-2016	12-31-2049
AURORANewRes 488	New No 14149 Wind 100 MW	na	0	100000	7	01-01-2016	12-31-2049
AURORANewRes 489	New No 14336 Wind 100 MW	na	0	100000	8	01-01-2010	12-31-2049
AURORANewRes 49	New No 5538 CCCT 280 MW	na	6423	280000	2	01-01-2017	12-31-2049
AURORANewRes 490	New No 14339 Wind 100 MW	na	0	100000	8	01-01-2010	12-31-2049
AURORANewRes 491	New No 14340 Wind 100 MW	na	0	100000	8	01-01-2010	12-31-2049
AURORANewRes 492	New No 14341 Wind 100 MW	na	0	100000	8	01-01-2010	12-31-2049
AURORANewRes 493	New No 14343 Wind 100 MW	na	0	100000	8	01-01-2010	12-31-2049
AURORANewRes 494	New No 14344 Wind 100 MW	na	0	100000	8	01-01-2010	12-31-2049
AURORANewRes 495	New No 14350 Wind 100 MW	na	0	100000	8	01-01-2011	12-31-2049
AURORANewRes 496	New No 14351 Wind 100 MW	na	0	100000	8	01-01-2011	12-31-2049
AURORANewRes 497	New No 14352 Wind 100 MW	na	0	100000	8	01-01-2011	12-31-2049
AURORANewRes 498	New No 14354 Wind 100 MW	na	0	100000	8	01-01-2011	12-31-2049
AURORANewRes 499	New No 14587 Wind 100 MW	na	0	100000	9	01-01-2010	12-31-2049
AURORANewRes 5	New No 3164 Coal 400 MW	na	9402	400000	7	01-01-2011	12-31-2049
AURORANewRes 50	New No 5539 CCCT 280 MW	na	6423	280000	2	01-01-2017	12-31-2049
AURORANewRes 500	New No 14593 Wind 100 MW	na	0	100000	9	01-01-2010	12-31-2049
AURORANewRes 501	New No 14597 Wind 100 MW	na	0	100000	9	01-01-2011	12-31-2049
AURORANewRes 502	New No 14598 Wind 100 MW	na	0	100000	9	01-01-2011	12-31-2049
AURORANewRes 503	New No 14599 Wind 100 MW	na	0	100000	9	01-01-2011	12-31-2049
AURORANewRes 504	New No 14600 Wind 100 MW	na	0	100000	9	01-01-2011	12-31-2049
AURORANewRes 505	New No 14601 Wind 100 MW	na	0	100000	9	01-01-2011	12-31-2049
AURORANewRes 506	New No 14602 Wind 100 MW	na	0	100000	9	01-01-2011	12-31-2049
AURORANewRes 507	New No 14603 Wind 100 MW	na	0	100000	9	01-01-2011	12-31-2049
AURORANewRes 508	New No 14604 Wind 100 MW	na	0	100000	9	01-01-2011	12-31-2049
AURORANewRes 509	New No 14896 Wind 100 MW	na	0	100000	10	01-01-2016	12-31-2049
AURORANewRes 51	New No 5540 CCCT 280 MW	na	6423	280000	2	01-01-2017	12-31-2049
AURORANewRes 510	New No 14897 Wind 100 MW	na	0	100000	10	01-01-2016	12-31-2049
AURORANewRes 511	New No 14899 Wind 100 MW	na	0	100000	10	01-01-2016	12-31-2049
AURORANewRes 512	New No 14900 Wind 100 MW	na	0	100000	10	01-01-2016	12-31-2049
AURORANewRes 513	New No 14901 Wind 100 MW	na	0	100000	10	01-01-2016	12-31-2049
AURORANewRes 514	New No 14902 Wind 100 MW	na	0	100000	10	01-01-2016	12-31-2049

Resource #	Name	Utility	Heat Rate	Capacity (kW)	Load Area	Begin Date	Retire Date
AURORANewRes 515	New No 14909 Wind 100 MW	na	0	100000	10	01-01-2017	12-31-2049
AURORANewRes 516	New No 14916 Wind 100 MW	na	0	100000	10	01-01-2018	12-31-2049
AURORANewRes 517	New No 14918 Wind 100 MW	na	0	100000	10	01-01-2018	12-31-2049
AURORANewRes 518	New No 14920 Wind 100 MW	na	0	100000	10	01-01-2018	12-31-2049
AURORANewRes 519	New No 15119 Wind 100 MW	na	0	100000	11	01-01-2013	12-31-2049
AURORANewRes 52	New No 5544 CCCT 280 MW	na	6423	280000	2	01-01-2017	12-31-2049
AURORANewRes 520	New No 15122 Wind 100 MW	na	0	100000	11	01-01-2013	12-31-2049
AURORANewRes 521	New No 15147 Wind 100 MW	na	0	100000	11	01-01-2016	12-31-2049
AURORANewRes 522	New No 15152 Wind 100 MW	na	0	100000	11	01-01-2016	12-31-2049
AURORANewRes 523	New No 15159 Wind 100 MW	na	0	100000	11	01-01-2017	12-31-2049
AURORANewRes 524	New No 15170 Wind 100 MW	na	0	100000	11	01-01-2018	12-31-2049
AURORANewRes 525	New No 15171 Wind 100 MW	na	0	100000	11	01-01-2018	12-31-2049
AURORANewRes 526	New No 15172 Wind 100 MW	na	0	100000	11	01-01-2018	12-31-2049
AURORANewRes 527	New No 15174 Wind 100 MW	na	0	100000	11	01-01-2018	12-31-2049
AURORANewRes 528	New No 15188 Wind 100 MW	na	0	100000	11	01-01-2020	12-31-2049
AURORANewRes 529	New No 15346 Wind 100 MW	na	0	100000	12	01-01-2011	12-31-2049
AURORANewRes 53	New No 5545 CCCT 280 MW	na	6423	280000	2	01-01-2017	12-31-2049
AURORANewRes 530	New No 15347 Wind 100 MW	na	0	100000	12	01-01-2011	12-31-2049
AURORANewRes 531	New No 15348 Wind 100 MW	na	0	100000	12	01-01-2011	12-31-2049
AURORANewRes 532	New No 15349 Wind 100 MW	na	0	100000	12	01-01-2011	12-31-2049
AURORANewRes 533	New No 15350 Wind 100 MW	na	0	100000	12	01-01-2011	12-31-2049
AURORANewRes 534	New No 15351 Wind 100 MW	na	0	100000	12	01-01-2011	12-31-2049
AURORANewRes 535	New No 15352 Wind 100 MW	na	0	100000	12	01-01-2011	12-31-2049
AURORANewRes 536	New No 15353 Wind 100 MW	na	0	100000	12	01-01-2011	12-31-2049
AURORANewRes 537	New No 15354 Wind 100 MW	na	0	100000	12	01-01-2011	12-31-2049
AURORANewRes 538	New No 15355 Wind 100 MW	na	0	100000	12	01-01-2011	12-31-2049
AURORANewRes 539	New No 15583 Wind 100 MW	na	0	100000	13	01-01-2009	12-31-2049
AURORANewRes 54	New No 5546 CCCT 280 MW	na	6385	280000	2	01-01-2018	12-31-2049
AURORANewRes 540	New No 15585 Wind 100 MW	na	0	100000	13	01-01-2009	12-31-2049
AURORANewRes 541	New No 15586 Wind 100 MW	na	0	100000	13	01-01-2010	12-31-2049
AURORANewRes 542	New No 15588 Wind 100 MW	na	0	100000	13	01-01-2010	12-31-2049
AURORANewRes 543	New No 15589 Wind 100 MW	na	0	100000	13	01-01-2010	12-31-2049
AURORANewRes 544	New No 15590 Wind 100 MW	na	0	100000	13	01-01-2010	12-31-2049
AURORANewRes 545	New No 15592 Wind 100 MW	na	0	100000	13	01-01-2010	12-31-2049
AURORANewRes 546	New No 15593 Wind 100 MW	na	0	100000	13	01-01-2010	12-31-2049
AURORANewRes 547	New No 15595 Wind 100 MW	na	0	100000	13	01-01-2010	12-31-2049
AURORANewRes 548	New No 15599 Wind 100 MW	na	0	100000	13	01-01-2011	12-31-2049
AURORANewRes 549	New No 16087 Wind 100 MW	na	0	100000	14	01-01-2010	12-31-2049
AURORANewRes 55	New No 5548 CCCT 280 MW	na	6385	280000	2	01-01-2018	12-31-2049
AURORANewRes 550	New No 16088 Wind 100 MW	na	0	100000	14	01-01-2010	12-31-2049
AURORANewRes 551	New No 16094 Wind 100 MW	na	0	100000	14	01-01-2010	12-31-2049
AURORANewRes 552	New No 16096 Wind 100 MW	na	0	100000	14	01-01-2011	12-31-2049
AURORANewRes 553	New No 16101 Wind 100 MW	na	0	100000	14	01-01-2011	12-31-2049
AURORANewRes 554	New No 16102 Wind 100 MW	na	0	100000	14	01-01-2011	12-31-2049
AURORANewRes 555	New No 16104 Wind 100 MW	na	0	100000	14	01-01-2011	12-31-2049
AURORANewRes 556	New No 16117 Wind 100 MW	na	0	100000	14	01-01-2013	12-31-2049
AURORANewRes 557	New No 16119 Wind 100 MW	na	0	100000	14	01-01-2013	12-31-2049

Resource #	Name	Utility	Heat Rate	Capacity (kW)	Load Area	Begin Date	Retire Date
AURORANewRes 558	New No 16120 Wind 100 MW	na	0	100000	14	01-01-2013	12-31-2049
AURORANewRes 559	New No 16333 Duke Moapa 1 CCCT 610 MW	na	6659	610000	14	01-01-2011	12-31-2049
AURORANewRes 56	New No 5550 CCCT 280 MW	na	6385	280000	2	01-01-2018	12-31-2049
AURORANewRes 560	New No 16358 Duke Moapa 2 CCCT 610 MW	na	6659	610000	14	01-01-2011	12-31-2049
AURORANewRes 561	New No 16377 DSM Com HVAC 1	Avista Corp	0	8935.1	17	01-01-2005	12-31-2049
AURORANewRes 562	New No 16401 DSM Com Ltg 1	Avista Corp	0	2392.9	17	01-01-2004	12-31-2049
AURORANewRes 563	New No 16532 DSM Com HVAC 2	Avista Corp	0	893.5	17	01-01-2010	12-31-2049
AURORANewRes 564	New No 16551 DSM Com Ltg 2	Avista Corp	0	239.3	17	01-01-2004	12-31-2049
AURORANewRes 565	New No 16682 DSM Com HVAC 3	Avista Corp	0	89.4	17	01-01-2010	12-31-2049
AURORANewRes 566	New No 16701 DSM Com Ltg 3	Avista Corp	0	23.9	17	01-01-2004	12-31-2049
AURORANewRes 567	New No 16832 DSM Com HVAC 4	Avista Corp	0	8.9	17	01-01-2010	12-31-2049
AURORANewRes 568	New No 16851 DSM Com Ltg 4	Avista Corp	0	2.4	17	01-01-2004	12-31-2049
AURORANewRes 57	New No 5551 CCCT 280 MW	na	6385	280000	2	01-01-2018	12-31-2049
AURORANewRes 58	New No 5552 CCCT 280 MW	na	6385	280000	2	01-01-2018	12-31-2049
AURORANewRes 59	New No 5553 CCCT 280 MW	na	6385	280000	2	01-01-2018	12-31-2049
AURORANewRes 6	New No 5339 CCCT 280 MW	na	6270	280000	1	01-01-2021	12-31-2049
AURORANewRes 60	New No 5554 CCCT 280 MW	na	6385	280000	2	01-01-2018	12-31-2049
AURORANewRes 61	New No 5557 CCCT 280 MW	na	6346	280000	2	01-01-2019	12-31-2049
AURORANewRes 62	New No 5558 CCCT 280 MW	na	6346	280000	2	01-01-2019	12-31-2049
AURORANewRes 63	New No 5559 CCCT 280 MW	na	6346	280000	2	01-01-2019	12-31-2049
AURORANewRes 64	New No 5563 CCCT 280 MW	na	6346	280000	2	01-01-2019	12-31-2049
AURORANewRes 65	New No 5564 CCCT 280 MW	na	6346	280000	2	01-01-2019	12-31-2049
AURORANewRes 66	New No 5565 CCCT 280 MW	na	6346	280000	2	01-01-2019	12-31-2049
AURORANewRes 67	New No 5568 CCCT 280 MW	na	6308	280000	2	01-01-2020	12-31-2049
AURORANewRes 68	New No 5569 CCCT 280 MW	na	6308	280000	2	01-01-2020	12-31-2049
AURORANewRes 69	New No 5574 CCCT 280 MW	na	6308	280000	2	01-01-2020	12-31-2049
AURORANewRes 7	New No 5340 CCCT 280 MW	na	6270	280000	1	01-01-2021	12-31-2049
AURORANewRes 70	New No 5575 CCCT 280 MW	na	6308	280000	2	01-01-2020	12-31-2049
AURORANewRes 71	New No 5576 CCCT 280 MW	na	6270	280000	2	01-01-2021	12-31-2049
AURORANewRes 72	New No 5577 CCCT 280 MW	na	6270	280000	2	01-01-2021	12-31-2049
AURORANewRes 73	New No 5578 CCCT 280 MW	na	6270	280000	2	01-01-2021	12-31-2049
AURORANewRes 74	New No 5584 CCCT 280 MW	na	6270	280000	2	01-01-2021	12-31-2049
AURORANewRes 75	New No 5591 CCCT 280 MW	na	6233	280000	2	01-01-2022	12-31-2049
AURORANewRes 76	New No 5600 CCCT 280 MW	na	6195	280000	2	01-01-2023	12-31-2049
AURORANewRes 77	New No 5602 CCCT 280 MW	na	6195	280000	2	01-01-2023	12-31-2049
AURORANewRes 78	New No 5603 CCCT 280 MW	na	6195	280000	2	01-01-2023	12-31-2049
AURORANewRes 79	New No 5610 CCCT 280 MW	na	6158	280000	2	01-01-2024	12-31-2049
AURORANewRes 8	New No 5345 CCCT 280 MW	na	6270	280000	1	01-01-2021	12-31-2049
AURORANewRes 80	New No 5611 CCCT 280 MW	na	6158	280000	2	01-01-2024	12-31-2049
AURORANewRes 81	New No 5612 CCCT 280 MW	na	6158	280000	2	01-01-2024	12-31-2049
AURORANewRes 82	New No 5615 CCCT 280 MW	na	6158	280000	2	01-01-2024	12-31-2049
AURORANewRes 83	New No 5621 CCCT 280 MW	na	6121	280000	2	01-01-2025	12-31-2049
AURORANewRes 84	New No 5622 CCCT 280 MW	na	6121	280000	2	01-01-2025	12-31-2049
AURORANewRes 85	New No 5623 CCCT 280 MW	na	6121	280000	2	01-01-2025	12-31-2049
AURORANewRes 86	New No 5624 CCCT 280 MW	na	6121	280000	2	01-01-2025	12-31-2049
AURORANewRes 87	New No 5625 CCCT 280 MW	na	6121	280000	2	01-01-2025	12-31-2049
AURORANewRes 88	New No 5626 CCCT 280 MW	na	6085	280000	2	01-01-2026	12-31-2049

Resource #	Name	Utility	Heat Rate	Capacity (kW)	Load Area	Begin Date	Retire Date
AURORANewRes 89	New No 5627 CCCT 280 MW	na	6085	280000	2	01-01-2026	12-31-2049
AURORANewRes 9	New No 5351 CCCT 280 MW	na	6233	280000	1	01-01-2022	12-31-2049
AURORANewRes 90	New No 5628 CCCT 280 MW	na	6085	280000	2	01-01-2026	12-31-2049
AURORANewRes 91	New No 5629 CCCT 280 MW	na	6085	280000	2	01-01-2026	12-31-2049
AURORANewRes 92	New No 5630 CCCT 280 MW	na	6085	280000	2	01-01-2026	12-31-2049
AURORANewRes 93	New No 5633 CCCT 280 MW	na	6085	280000	2	01-01-2026	12-31-2049
AURORANewRes 94	New No 5636 CCCT 280 MW	na	6048	280000	2	01-01-2027	12-31-2049
AURORANewRes 95	New No 5638 CCCT 280 MW	na	6048	280000	2	01-01-2027	12-31-2049
AURORANewRes 96	New No 5639 CCCT 280 MW	na	6048	280000	2	01-01-2027	12-31-2049
AURORANewRes 97	New No 5640 CCCT 280 MW	na	6048	280000	2	01-01-2027	12-31-2049
AURORANewRes 98	New No 5651 CCCT 280 MW	na	6012	280000	2	01-01-2028	12-31-2049
AURORANewRes 99	New No 5654 CCCT 280 MW	na	6012	280000	2	01-01-2028	12-31-2049

Appendix

K

Spokane River Relicensing

The Spokane River Project consists of five hydroelectric developments (HEDs): Post Falls, Upper Falls, Monroe Street, Nine Mile, and Long Lake. The project produces an average of 95 MW of power at an approximate cost of $24/MWH. The operation of these developments is governed in a single license issued by FERC, #2545. This license expires at the end of July 2007.

The Federal Power Act (FPA) of 1920 provides the Federal Energy Regulatory Commission (FERC) exclusive authority to license all nonfederal hydroelectric projects that are located on navigable waterways or federal lands. New licenses are normally issued for a period of 30 to 50 years.

The FERC relicensing process requires years of extensive planning, including environmental studies, agency consensus and public involvement. The FPA was amended in 1986 by the Electric Consumers Protection Act (ECPA). The amended law requires that FERC give equal consideration to the non-generating benefits of the natural resource (fish, wildlife, aesthetics, water quality, land use, and recreational resources, for example) along with the benefit of power production. This range of issues is addressed through a consultation process, outlined in FERC rules. In addition, other reviewing and conditioning authorities come into play, including the National Environmental Policy Act (NEPA), the Clean Water Act, the Endangered Species Act, and several portions of the Federal Power Act that create specific licensing conditioning authorities.

These additional authorities reside in agencies at the local, state and federal level. In addition, since the U.S. Supreme Court ruled that the Coeur d'Alene tribe owns the southern portion of Lake Coeur d'Alene, the tribe has a significant stake in relicensing. Avista must negotiate past and future storage charges with the tribe per Section 10(e) of the FPA. In addition, since the project occupies federally-reserved lands for the tribe, the Bureau of Indian Affairs has mandatory conditioning authority for a new project license, meaning that FERC has no discretion regarding such conditions.

Consequently, the relicensing process can be very complicated, and at times has led to extended conflict between interests. In an effort to resolve the range of issues in a more productive fashion, relicensing efforts have more recently shifted to provide increased opportunity to collaborate on issue resolution. This shift, recognized as the "Alternative Licensing Procedures," (ALP) also aims to improve coordination between the various legal authorities that come into play during relicensing.

Avista began the relicensing process for this project several years ago with a series of stakeholder interviews. This was near the end of the Clark Fork relicensing effort, which had helped pioneer what became the ALP.

In 2001, two stakeholder meetings were held to form the relicensing team. In addition, the team developed a Communications Protocol and Guiding Principles document. Through these efforts, broad agreement developed to use the ALP. We made a request to FERC for approval to use the ALP in April 2002. FERC approved the request in June 2002. We filed our formal Notice of Intent to relicense the project in July 2002.

The ALP is a collaborative approach to decision-making for relicensing. The goal is to develop a broad agreement that, in effect, would constitute our new license application. Over 100 stakeholder groups are involved in this effort, including: the Coeur d'Alene Tribe, U.S. Fish and Wildlife Service, Bureau of Land Management, U.S. Forest Service, Idaho Department of Environmental Quality, the Washington Department of Ecology, Washington Department of Fish and Wildlife, Idaho Department of Fish and Game, Spokane Tribe, various local governments, non-governmental interest groups, and numerous landowners and other individuals. The setting of the project, extending through two states and several cities, as well as the broad range of other concerns regarding the lakes, river, land use, etc. create a challenging relicensing atmosphere.

Five technical work groups, and a lead or plenary group constitute the effort currently. The work groups have been meeting monthly to identify and discuss issues and scope studies, and will ultimately propose protection, mitigation and enhancement measures. The upcoming year, 2003, is the primary study season. Additional studies will follow in 2004, as will development of proposals guiding a new license application. We must file our new application by the end of July 2005.

Relicensing has been proceeding with difficulty this year, given the wide range of interest and high expectations of stakeholders. Our goal continues to be to reach a settlement agreement and avoid the costs associated with protracted disagreement or heavy-handed unilateral agency decision-making. A corollary goal is to develop, through this process, strong relationships with the broad ranges of stakeholders that will help sustain shared interests during the implementation of a new license.

Appendix

L

Transmission Planning

Relationship to Resource Planning

Avista (Transmission) system Planning and Operations continues to respond to the requests from Resource Planning for integration of resources to serve retail load. As Resource Planning analyses installation of additional generation on the system, it will make requests for studies from System Planning. System Planning will investigate the impacts and provide information as requested to Resource Planing for use in evaluation of the cost-effectiveness of various resource options. System Planning's goal is to provide reliability and maximize the efficient use of the transmission system.

Current Issues

Avista System Planning and Transmission Operations faces an uncertain future as a result of the on-going restructuring of the Electric Transmission businesses as the industry moves toward a more deregulated market. This turmoil includes several activities:

1. **An increased emphasis on reliability.** Both the North American Electric Reliability Council (NERC) and the Western Electric Coordination Council (WECC) have instigated a move toward mandatory compliance with reliability and operating criteria.
2. **An increased emphasis on operational studies** to determine the simultaneous capability of transfer paths. This has resulted in the formation of four regional study groups that determine simultaneous and non-simultaneous capabilities of all impacted transfer paths. Included in this is the Northwest Operational Planning Study Group in which Avista participates. The rule for operation states simply: if the flow pattern hasn't been studied to assure system integrity, then the system cannot be operated in that way.
3. A move toward consolidation of transmission resources into larger organization so that it will be more completely separate from any merchant entities. On December 20, 1999 the Federal Energy Regulatory Commission (FERC) issued its final rule (Order No. 2000) regarding **the development of Regional Transmission Organizations (RTOs).** For further information please see the write-up on RTOs and Avista's relationship with the RTO West.

The big impact of #1 above is that previous to this move toward mandatory compliance, utilities could occasionally violate WECC reliability criteria (usually unintentional) as long as there were no detrimental effects on neighboring systems. Mandatory Compliance states that utilities must now meet all criteria within their own boundaries as well as not affecting others. On June 18, 1999 the majority of the members of the WECC signed agreements to participate in the WECC's Reliability Management System (RMS). This system tracks violations of operating and planning criteria with consequences ranging from letters to management and State Utility Commissions to monetary penalties. The initial RMS implementation included only critical operating criteria. A pilot NERC compliance program is under way that will eventually blend with RMS. Ultimately there will be a complete Mandatory Compliance system that will require utilities to get a long list of important operating and planning criteria. The consequences for non-compliance may be severe and include monetary penalties. The full implementation of Mandatory Compliance will require national legislation to be effective and binding.

The **increased emphasis on operational studies** is a result of de-regulation and other factors that put the transmission system of the Western Interconnection at a potentially higher operational risk. The two large widespread outages in 1996 contributed to the urgency of making sure the transmission system can handle transfer needs in each upcoming operating season. While local interconnection studies are being performed, it is nearly impossible to do long range system wide planning because no one knows what new generation will come to fruition and what the actual generation patterns will be. Other factors, such as changes in generation patterns on the Columbia river to help mitigate fish depletion have added complexity to planning studies. As a result of all of this, more emphasis is being put on the near term “operational” studies rather than longer term “planning” studies. Each sub-region will analyze the allowable transfer levels for recognized transfer paths. Avista is an active participant in the Northwest Operational Planning Study Group.

Expansion Possibilities & System Reconfiguration

The impact of expansion on the Avista transmission system is largely dependent upon the location of the proposed expansion. Some of the possible solutions to various system constraints may have the added benefit of making load and generation additions more easy to integrate. These solutions include possible conversions of parts of the 115 kV system to a radial rather than looped system and a significant amount of additional or reconductored 230 kV transmission lines. Any new load or generation integration will continue to be handled on a case by case basis.

Reliability

Avista’s transmission system is planned, designed, constructed and operated to meet peak load demands and peak load transfers while assuring continuity of service during system disturbances and to be consistent with sound economic planning principles. FERC Form 715 includes the planning limits of both the transmission lines and transformer capabilities for the Avista system. Avista Planning uses the Western Electric Coordinating Council’s “Reliability Criteria for System Design” as a benchmark to determine the performance of Avista’s system in relation to interconnections with other Northwest regions and utilities.

Appendix

M Distributed Generation

Distributed Generation (DG) is defined as:
Generation, storage, or DSM devices, measures and/or technologies that are connected to or injected into the distribution level of the power delivery grid.

Potential benefits of DG:

- reduce circuit load
- reduce/deter T&D line construction
- customer satisfaction/service
- peak shaving
- voltage support
- fuel diversity
- increased reliability of service (some applications)
- reduced losses
- environmental advantages (i.e. burn landfill methane gas)

Potential disadvantages of DG:

- Intermittent power production (solar and wind)
- High initial capital costs
- Fuel supply and price (fuel cells, microturbines, etc.)
- Unknown maintenance cost
- Lower efficiencies
- No universally accepted standards for grid interconnection
- Need transfer switch to prevent back feed of electricity
- If power is sold to a utility, need power purchase agreement

There are some difficulties in connecting DG with the grid. In August 2002 FERC issued an advance notice of proposed rulemaking seeking comments on standard small generator (less than 20 MW) interconnection agreements. The problems stem from:

- Lack of uniform standards and procedures.
- Project approval is too long.
- Application and interconnection fees frequently are viewed as arbitrary.
- Utility imposed operational requirements.
- Backup or standby charges are viewed as a rate-related barrier.

Power generation economics (including DG) depend on first cost, running efficiencies, fuel cost (where applicable) and maintenance costs. Site suitability depends on size, weight, emissions, noise and other factors. DG projections are that by 2015 the United States could account for some 51,000 MW of installed capacity or about 5 percent of the national total. The amount of DG presently in the U.S. is 60,000 but most of this is not connected to the grid. DG will be most economically attractive to electric utilities in scenarios where they are faced with system constraints, particularly in transmission and distribution. For the end user, economics are improved if customers can capture additional benefits such as reduced fuel costs for stream and hot water through combined heat and power. Small DG equipment will fill niche markets where T&D lines are constrained, peak loads are excessive, cogeneration opportunities exist, or grid reliability is questioned. DG is generally defined as under 50 MW, but the majority of the systems installed are rated less than 10 MW.

With the exception of Capstone Turbine, the microturbine market is several years from general deployment. Commercial fuel cells are even further out but making gains. The real action in DG is in natural gas reciprocating engines.

While the electric grid will certainly be powering the country for years to come, more and more consumers will be augmenting their power supply with onsite power. Whatever the technology, energy in the future will come from a variety of sources. The following is a list of DG sources:

Biomass

Generation from biomass is normally derived from methane gas (landfills etc.), municipal solid waste, and cropland and/or forest materials. The Company's service territory has examples of all three (Minnesota Methane plant, Spokane solid waste facility and Kettle Falls wood-fired plant). When generation is from wood wastes, the excess steam is used for other purposes (ex. kiln drying) which greatly improve the overall efficiency.

The Company had a wood waste cogeneration facility bid in its last RFP. The price was about 70 mills/kWh. From past experiences the total cost of a wood-waste facility is between 50 and 70 mills/kWh.

Regulus Stud Mill has inquired about a power purchase contract and would probably start construction when the avoided costs are sufficient to support the development. This facility would be between 2.5 and 5.0 MWs.

Combustion Turbines

Conventional combustion turbine generators typically range in size from about 500 kW up to 25 MW for distribution applications. Fuels include natural gas, oil or a combination. Modern single-cycle combustion turbine units typically have efficiencies in the range of 20 to 45 percent at full load. When operating at less than full load, efficiencies can fall by as much as 25 percent. Depending on size, costs can range between 300 and 650 $/kW, with the larger size units costing less. Costs of 1000 $/kW or more include a gas compressor (usually needed), installation costs and heat recovery capability.

Fuel Cells

Fuel cells convert hydrogen gas to electricity through an electrochemical process, which does not involve combustion. These chemical reactions produce electricity, heat, and water with zero emissions. Fuel cells, therefore, are inherently quiet, have the potential to be environmentally benign, and very efficient.

Fuel cells use hydrogen as the fuel and therefore need a cost-effective way to reform other available fuels into hydrogen. Some of the fuels presently being used are natural gas, propane, methanol, and diesel. There are five fuel cell technologies, named for their respective electrolytes, ranging in operating temperatures from 50 degrees C. to 1000 degrees C. These are: solid polymer or proton exchange membrane (PEM), alkaline, phosphoric acid (PAFC), molten carbonate (MCFC), and solid oxide (SOFC). 200 kW phosphoric acid fuel cells have been commercially available for the past few years. In the long run solid oxide fuel cells technologies may hold the most promise, although the leading fuel cell technology at the moment is the PEM cell. PEM is better suited for the transportation sector because they are lighter weight, start fast and have lower temperatures.

Fuel cells today range in size from 1 kW to 3000 kW based on their configuration. The efficiencies are between 36 and 60 percent and the installation cost range is determined to be 4000 to 5000 $/kW. The range of variable costs is 1.9 to 15.3 mills/kWh without the cost of fuel.

Geothermal

Geothermal is a generating facility that uses the heat of the earth as its energy source. These facilities are very site specific as relating to costs, etc. Some of the existing sites are generating at a range of 50 to 60 mills/kWh.

Manure-To-Energy Digester

Using manure as a fuel for generating plants has been used in other areas. Presently there are a few sites being evaluated for these facilities in the northwest. It takes about one dairy cow to produce the fuel for 0.3 kW. Estimated capital costs are about $2800/kW.

Microturbines

Microturbines are in the market place as a substitute for internal combustion engines. They burn a variety of fuels (natural gas, hydrogen, propane or diesel) and come in a wide range of sizes, 25 kW to 500 kW. The efficiencies range from 14 to 30 percent, although the majority of units have about 27 percent. Capstone claims 70 to 80 percent efficiency when the unit is part of a more expensive cogeneration system. Microtrubines have low NOx emissions making them environmentally friendly. Without cogeneration, the capital costs range from 500 to 1200 $/kW with variable costs of 4 to 10 mills/kWh.

Reciprocating Engine

The most common alternate power source is the reciprocating engine. Fuels include natural gas, diesel, landfill gas and digester gas. Reciprocating engines have higher emissions than many alternatives and therefore usually require pollution control technology. They tend to be highly reliable, but require more maintenance.

- *Diesel*: The cost and efficiency of these engines have a lot to do with their size. Size range is between 20 kW and 6+ MW with costs of 350 to 500 $/kW and with an efficiency of between 30 and 45 percent. Variable costs range between 5 and 15 mills/kWh. These units have a proven niche as standby generation in commercial and industrial applications and dominate the DG market place.

- *Natural Gas*: These engines have basically the same characteristics as the diesel engines but with a slightly higher capital and variable operating costs (7 to 20 mills/kWh). These units generally have a range in size of 5 kW to 6 MW.

Ride-Through Technologies

There is a question if these technologies should be classified as DG. The difference between this technology and DG is the time period in which the systems provide power to the load. In other words, these systems have a finite period of time in providing energy. These technologies include flywheel, battery, capacitors, magnetic energy storage, compressed air, and micro-pumped storage. These energy storage facilities improve the efficiency, reliability and security for DG systems plus they eliminate voltage swings because of shifting power loads.

The flywheel technology normally replaces batteries. Temperature ranges have no effect and their life should be decades not years. Flywheels are generally in the 150 kW to 1 MW range. Six kWh systems are presently in operation.

Small Hydro

There are several small hydro facilities operating in the Company's service territory. Renewable generating facilities, such as hydro, are encouraged by the federal legislation called PURPA. Since the fuel is usually free, the major cost of these facilities is the capital.

Solar

Solar systems are still higher in cost than other forms of DG. There are two types of solar generation, central solar station and photovoltaic. Thin film photovoltaic technology has been commercial for several years and is usually just a few kW in size. Solar costs are 4000 to 10,000 $/kW with energy costs of 200 to 400 mills/kWh. Although the costs are presently around $6/watt, the goal is to have the cost down to $3/watt in the next few years.

There are many examples of solar generating systems. There is one located in downtown Spokane that is 10 kW in size and cost $100,000 to install. A solar station in Mojave Desert, CA of several megawatts produces energy at 150 mills/kWh. Another system in Kipland, CA has a 28 percent plant factor. Another solar station near Richland, WA cost $8,000/kW.

Wind

Wind generation has had a significant increase throughout the world with a corresponding decrease in costs. There are approximately 17,000 MW of wind generation installed worldwide. There are wind turbines now installed in 26 states. The five states with the greatest wind potential are North Dakota, Texas, Kansas, South Dakota and Montana. One of the largest wind farms is located in the northwest, the 293 MW Stateline Wind Generating Project.

The average cost of wind has decreased about 80 percent during the past decade. About half of the decrease is the result of improved efficiency and economies of scale and the other half is from improved manufacturing techniques.

The main problem with wind energy is that it is inconsistent. Having an intermittent fuel source makes it difficult to schedule to serve firm loads. The capacity factor on the best sites that are being developed is normally 25 to 30 percent. There has been one published capacity factor of 40 percent.

Some of the advantages for wind generation is it is renewable, no escalation in cost due to fuel prices, and no air pollutants. There is also a federal tax credit of 17 mills/kWh for the first 10 years. So over the life of the facility (est. 20 years) it would reduce costs by about 7 mills.

Small wind turbines, that are available for home installations, have costs that range from 2500 to 5000 $/kW. The smaller sizes are usually from a few kW to about 50 kW. These units require from 3 to 5 mph winds to start operating. A 10 kW home wind kit was advertised for $27,000.

The large wind turbines used in commercial wind farms are sized from 250 kW to over 1,500 kW. These units need 7 mph wind to start and at least 13 mph average annual wind speed to be cost effective. The capital cost range from 700 to 1100 $/kW and produce energy at 40 to 60 mills/kWh before the tax credit is applied.

Installed Costs

DG installed costs can be as high as 2.5 times the equipment costs.

Reciprocating Engines	700 to 1500 $/kW
Gas Turbines	1000 to 1500
Microturbines	1500 to 2000
Fuel Cells	4000 to 5000

Reliability

DG reliability is by nature a case-by-case issue. Most DG applications will probably have little impact on the reliability of the distribution system, as it is presently measured. Supporting the distribution system with DG can mutually benefit utilities and customers but can negatively impact reliability. Where and how DG is interconnected determines its value to the system.

The Company's View

The Company views DG as not a threat but as another choice available to the utility. In the future there will be a vibrant market for personalized power that uses DG technology. The Company is financially supporting fuel cell development and therefore is a part of the DG movement. The key to any DG project is the source location relative to the substation. Presently within the Company, any proposed DG project includes analysis to look at the effects on its system.

Appendix

N Historic Data

Hydroelectric Plants

Post Falls
FERC License Expiration Date: 07/31/2007

Rated Capacity:	Total	No. 1	No. 2	No. 3	No. 4	No. 5	No. 6
(Peak in MW)	18.0	2.9	2.9	2.9	2.9	2.9	3.5

Upper Falls
FERC License Expiration Date: 07/31/2007

Rated Capacity:	Total	No. 1
(Peak in MW)	10.2	10.2

Monroe Street
FERC License Expiration Date: 07/31/2007

Rated Capacity:	Total	No. 1
(Peak in MW)	14.8	14.8

Nine Mile
FERC License Expiration Date: 07/31/2007

Rated Capacity:	Total	No. 1	No. 2	No. 3	No. 4
(Peak in MW)	24.5	4.1	4.1	8.1	8.2

Long Lake
FERC License Expiration Date: 07/31/2007

Rated Capacity:	Total	No. 1	No. 2	No. 3	No. 4
(Peak in MW)	88.0	22.0	22.0	22.0	22.0

Little Falls
FERC License Expiration Date: N/A (License not required)

Rated Capacity:	Total	No. 1	No. 2	No. 3	No. 4
(Peak in MW)	36.0	9.0	9.0	9.0	9.0

Maintenance and outage records for the above plants are not computerized and exist in log style handwritten form. It would take many man-hours to obtain the necessary data to determine accurate forced outage and availability data. Because of this, five years of data is not included. The data is available for inspection or recording at any time.

Noxon Rapids
FERC License Expiration Date: 03/01/2046

Rated Capacity:	Total	No. 1	No. 2	No. 3	No. 4	No. 5
(Peak in MW)	527	102	102	102	91	130

Year	Month	Forced Outage Rate	Equivalent Availability Factor
1998	Jan	0.98	99.40
	Feb	0.00	100.00
	Mar	1.08	97.53
	Apr	0.37	99.82
	May	1.17	98.62
	Jun	0.00	100.00
	Jul	0.00	99.57
	Aug	8.21	96.00
	Sep	2.99	92.14
	Oct	4.35	90.39
	Nov	0.38	98.37
	Dec	0.35	99.74
1999	Jan	0.02	99.88
	Feb	0.01	95.27
	Mar	0.00	93.12
	Apr	0.26	99.82
	May	0.00	100.00
	Jun	0.00	99.67
	Jul	0.00	99.86
	Aug	0.00	100.00
	Sep	N/A	N/A
	Oct	2.66	75.74
	Nov	0.00	80.00
	Dec	0.03	91.19
2000	Jan	0.06	99.82
	Feb	0.43	99.72
	Mar	0.00	93.42
	Apr	0.00	100.00
	May	0.00	100.00
	Jun	0.00	100.00
	Jul	0.00	100.00
	Aug	1.53	99.16
	Sep	0.00	97.78
	Oct	0.00	87.42
	Nov	1.54	79.15
	Dec	0.00	93.33

Year	Month	Forced Outage Rate	Equivalent Availability Factor
2001	Jan	0.00	100.00
	Feb	0.00	99.97
	Mar	0.40	81.75
	Apr	0.00	100.00
	May	0.22	99.84
	Jun	0.65	99.58
	Jul	0.05	99.98
	Aug	0.46	83.53
	Sep	0.27	96.95
	Oct	46.91	38.67
	Nov	53.27	59.53
	Dec	22.46	72.51
2002	Jan	0.04	85.79
	Feb	0.19	87.36
	Mar	0.22	79.93
	Apr	0.12	88.29
	May	0.37	99.67
	Jun	0.30	99.70
	Jul	0.16	99.49
	Aug	5.45	97.57
	Sep	0.00	99.93
	Oct	0.00	100.00
	Nov	0.87	92.43
	Dec	0.00	100.00

Equivalent Availability Factor = Availability Factor = (Available Unit Days/Period Unit Days) * 100.
Forced Outage Rate = (Forced Outage Unit Days/(Service Unit Days + Forced Outage Unit Days)) * 100.

Cabinet Gorge
FERC License Expiration Date: 03/01/2046

Rated Capacity:		Total	No. 1	No. 2	No. 3	No. 4
	(Peak in MW)	246	63.5	57.5	67.5	57.5

Year	Month	Forced Outage Rate	Equivalent Availability Factor	Year	Month	Forced Outage Rate	Equivalent Availability Factor
1998	Jan	1.11	97.86	2001	Jan	2.67	73.87
	Feb	0.02	99.27		Feb	0.00	74.81
	Mar	0.04	99.98		Mar	1.33	74.93
	Apr	0.00	100.00		Apr	0.00	100.00
	May	0.06	99.94		May	0.05	99.96
	Jun	0.01	99.99		Jun	0.00	99.92
	Jul	0.00	100.00		Jul	3.31	97.98
	Aug	0.01	100.00		Aug	0.00	99.13
	Sep	0.00	99.88		Sep	0.00	100.00
	Oct	0.08	91.84		Oct	0.00	100.00
	Nov	0.00	99.82		Nov	0.00	100.00
	Dec	0.32	99.63		Dec	0.00	100.00
1999	Jan	0.00	100.00	2002	Jan	0.00	99.94
	Feb	0.00	95.27		Feb	0.03	99.69
	Mar	0.00	100.00		Mar	0.00	100.00
	Apr	0.00	100.00		Apr	0.00	99.81
	May	0.01	99.99		May	0.19	99.82
	Jun	0.00	100.00		Jun	0.00	100.00
	Jul	0.05	99.96		Jul	0.00	100.00
	Aug	0.51	99.74		Aug	0.00	100.00
	Sep	0.00	100.00		Sep	0.00	100.00
	Oct	0.00	98.86		Oct	0.00	75.56
	Nov	0.00	100.00		Nov	0.00	78.32
	Dec	0.00	100.00		Dec	0.00	98.32
2000	Jan	0.00	99.58				
	Feb	0.00	100.00				
	Mar	0.00	100.00				
	Apr	0.62	99.48				
	May	0.00	100.00				
	Jun	0.00	100.00				
	Jul	0.00	100.00				
	Aug	0.00	100.00				
	Sep	0.00	77.50				
	Oct	0.00	75.00				
	Nov	0.00	75.00				
	Dec	0.99	74.26				

Equivalent Availability Factor = Availability Factor = (Available Unit Days/Period Unit Days) * 100.
Forced Outage Rate = (Forced Outage Unit Days/ (Service Unit Days + Forced Outage Unit Days)) * 100.

Coal-Fired Plants

Colstrip No. 3
Rated Capacity = 700 MW
Service Date = 1/10/1984
Design Plant Life = 35 years
Avista's Share = 15%

Year	Month	Forced Outage Rate	Equivalent Availability Factor	Year	Month	Forced Outage Rate	Equivalent Availability Factor
1998	Jan	8.51	84.98	2001	Jan	10.26	77.61
	Feb	15.19	85.01		Feb	0.00	95.68
	Mar	8.22	91.97		Mar	0.00	47.47
	Apr	0.00	86.53		Apr	0.00	0.00
	May	0.09	100.00		May	25.85	48.33
	Jun	0.00	100.00		Jun	0.05	99.63
	Jul	0.00	99.70		Jul	0.80	98.48
	Aug	13.14	87.08		Aug	1.61	97.01
	Sep	0.00	97.95		Sep	0.38	96.41
	Oct	27.42	71.73		Oct	0.67	92.01
	Nov	0.00	99.99		Nov	14.17	85.21
	Dec	0.00	99.61		Dec	0.00	98.60
1999	Jan	14.65	82.50	2002	Jan	85.51	14.32
	Feb	27.07	72.23		Feb	4.32	59.16
	Mar	11.34	86.98		Mar	3.29	96.62
	Apr	0.18	98.74		Apr	0.00	97.18
	May	0.00	69.43		May	0.00	97.84
	Jun	0.15	99.85		Jun	84.90	15.12
	Jul	17.37	81.59		Jul	84.30	12.67
	Aug	4.43	92.76		Aug	0.00	99.20
	Sep	0.10	90.98		Sep	10.50	87.76
	Oct	0.36	95.36		Oct	5.10	93.84
	Nov	18.77	79.71		Nov	27.40	71.09
	Dec	0.00	98.22		Dec	100.00	0.00
2000	Jan	9.55	88.97				
	Feb	2.46	97.04				
	Mar	0.00	99.75				
	Apr	16.11	84.49				
	May	22.63	15.02				
	Jun	10.83	87.11				
	Jul	14.74	82.43				
	Aug	6.82	81.48				
	Sep	0.24	92.81				
	Oct	0.00	95.23				
	Nov	0.43	94.26				
	Dec	16.53	83.70				

Note:
Avista uses 111 MW/unit based on an over pressure mode of operation.
Forced Outage Rate = Forced Outage Hours/ (Service Hours + Forced Outage Hours) * 100.
Equivalent Availability Factor:

(Available Hours – ((Derated Hours * size of Reduction)/ Maximum Capacity) * 100)/ Period Hours

Colstrip No. 4
Rated Capacity = 700 MW
Service Date = 4/6/1986
Design Plant Life = 35 years
Avista's Share = 15%

Year	Month	Forced Outage Rate	Equivalent Availability Factor
1998	Jan	0.00	98.11
	Feb	0.00	99.97
	Mar	0.00	95.58
	Apr	0.00	91.99
	May	0.12	47.40
	Jun	22.18	77.82
	Jul	7.22	93.83
	Aug	0.29	85.84
	Sep	0.25	90.99
	Oct	0.00	99.98
	Nov	25.28	74.52
	Dec	6.15	93.98
1999	Jan	1.97	93.95
	Feb	0.28	98.51
	Mar	9.33	89.78
	Apr	0.40	98.29
	May	0.12	97.78
	Jun	0.00	59.90
	Jul	0.50	72.31
	Aug	0.07	94.22
	Sep	0.00	98.71
	Oct	0.20	98.85
	Nov	0.00	99.89
	Dec	0.00	92.27
2000	Jan	12.67	87.03
	Feb	9.65	90.46
	Mar	3.38	96.65
	Apr	14.58	85.44
	May	3.43	97.78
	Jun	0.00	6.88
	Jul	36.71	57.15
	Aug	1.47	99.52
	Sep	91.53	8.47
	Oct	63.48	37.05
	Nov	0.86	98.50
	Dec	0.00	99.80
2001	Jan	0.00	99.85
	Feb	0.10	99.89
	Mar	0.00	96.09
	Apr	0.13	96.40
	May	7.80	91.15
	Jun	55.65	43.82
	Jul	11.18	88.41
	Aug	0.60	98.52
	Sep	0.36	89.95
	Oct	0.00	99.98
	Nov	0.00	95.59
	Dec	23.97	73.83
2002	Jan	12.86	81.42
	Feb	0.00	99.37
	Mar	0.40	79.45
	Apr	0.28	90.80
	May	0.00	98.94
	Jun	0.00	99.52
	Jul	0.70	98.76
	Aug	0.00	99.65
	Sep	10.72	87.65
	Oct	13.28	82.91
	Nov	0.00	85.53
	Dec	0.00	98.78

Note: Avista uses 111 MW/unit based on an over pressure mode of operation.

Other Resources

Kettle Falls
Rated Capacity = 50 MW
Service Date = 12/1/1983
Design Plant Life = 35 years

Year	Month	Forced Outage Rate	Availability Factor	Year	Month	Forced Outage Rate	Availability Factor
1998	Jan	0.00	100.00	2001	Jan	3.90	96.10
	Feb	4.40	95.60		Feb	0.00	100.00
	Mar	0.05	96.47		Mar	0.00	100.00
	Apr	0.00	100.00		Apr	0.22	99.78
	May	0.00	100.00		May	0.81	99.53
	Jun	0.00	0.00		Jun	0.11	99.89
	Jul	0.33	95.22		Jul	3.20	96.80
	Aug	0.25	99.75		Aug	0.12	99.88
	Sep	0.60	99.40		Sep	0.00	100.00
	Oct	0.52	99.61		Oct	0.05	99.95
	Nov	0.00	100.00		Nov	0.00	100.00
	Dec	2.81	97.19		Dec	0.04	99.97
1999	Jan	0.11	99.89	2002	Jan	0.19	99.81
	Feb	0.54	99.17		Feb	0.00	100.00
	Mar	0.48	99.64		Mar	17.16	82.84
	Apr	0.16	99.87		Apr	0.00	100.00
	May	0.00	100.00		May	0.00	100.00
	Jun	1.40	62.28		Jun	0.00	0.00
	Jul	0.19	99.85		Jul	0.00	0.00
	Aug	2.83	97.17		Aug	0.00	100.00
	Sep	1.97	98.03		Sep	5.84	94.16
	Oct	30.02	69.98		Oct	0.00	100.00
	Nov	0.59	99.41		Nov	2.70	97.30
	Dec	24.01	75.99		Dec	0.67	99.33
2000	Jan	4.76	95.24				
	Feb	2.25	97.75				
	Mar	0.09	99.91				
	Apr	10.58	90.02				
	May	0.14	99.92				
	Jun	4.41	95.59				
	Jul	4.91	95.09				
	Aug	0.23	99.77				
	Sep	0.00	100.00				
	Oct	0.00	100.00				
	Nov	1.10	98.90				
	Dec	0.00	100.00				

Availability Factor = (Available Hours/ Period Hours) * 100

PURPA Hydroelectric Plants

John Day Creek Hydroelectric Project/David Cereghino
Rated Capacity = 900 kW
Hours Connected to System = Not Available
Level of Dispatchability = none
Expiration Date = 9/21/2022

Year	Month	Generation-MWh	Year	Month	Generation-MWh
1998	Jan	156	2001	Jan	66
	Feb	142		Feb	30
	Mar	110		Mar	10
	Apr	141		Apr	30
	May	150		May	44
	Jun	428		Jun	400
	Jul	425		Jul	400
	Aug	430		Aug	219
	Sep	401		Sep	163
	Oct	307		Oct	86
	Nov	292		Nov	101
	Dec	268		Dec	85
1999	Jan	246	2002	Jan	175
	Feb	206		Feb	0
	Mar	148		Mar	0
	Apr	268		Apr	59
	May	286		May	117
	Jun	423		Jun	171
	Jul	395		Jul	412
	Aug	438		Aug	381
	Sep	354		Sep	209
	Oct	273		Oct	125
	Nov	202		Nov	107
	Dec	166		Dec	95
2000	Jan	124			
	Feb	74			
	Mar	85			
	Apr	88			
	May	108			
	Jun	367			
	Jul	389			
	Aug	211			
	Sep	60			
	Oct	110			
	Nov	121			
	Dec	85			

Note: Scheduled energy not metered energy.

Jim Ford Creek Power Project/Ford Hydro Limited Partnership
Rated Capacity = 1,500 kW
Hours Connected to System = Not Available
Level of Dispatchability = none
Expiration Date = 4.14.2023

Year	Month	Generation-MWh	Year	Month	Generation-MWh
1998	Jan	730	2001	Jan	48
	Feb	639		Feb	67
	Mar	894		Mar	267
	Apr	774		Apr	863
	May	516		May	850
	Jun	554		Jun	393
	Jul	433		Jul	315
	Aug	254		Aug	0
	Sep	51		Sep	0
	Oct	0		Oct	0
	Nov	0		Nov	15
	Dec	360		Dec	126
1999	Jan	587	2002	Jan	230
	Feb	1040		Feb	627
	Mar	665		Mar	650
	Apr	973		Apr	937
	May	942		May	888
	Jun	463		Jun	336
	Jul	84		Jul	149
	Aug	0		Aug	0
	Sep	0		Sep	0
	Oct	0		Oct	0
	Nov	3		Nov	0
	Dec	57		Dec	9
2000	Jan	418			
	Feb	360			
	Mar	892			
	Apr	994			
	May	719			
	Jun	438			
	Jul	73			
	Aug	0			
	Sep	0			
	Oct	0			
	Nov	25			
	Dec	7			

Big Sheep Hydroelectric Project/Sheep Creek Hydro, Inc.
Rated Capacity = 1,500 kW
Hours Connected to System = Not Available
Level of Dispatchability = none
Expiration Date = 6/4/2021

Year	Month	Generation-MWh
1998	Jan	898
	Feb	469
	Mar	830
	Apr	1218
	May	988
	Jun	1066
	Jul	1221
	Aug	575
	Sep	458
	Oct	139
	Nov	176
	Dec	317
1999	Jan	695
	Feb	748
	Mar	695
	Apr	1142
	May	1029
	Jun	1121
	Jul	1150
	Aug	1076
	Sep	703
	Oct	254
	Nov	161
	Dec	654
2000	Jan	422
	Feb	443
	Mar	1147
	Apr	1180
	May	1211
	Jun	1079
	Jul	898
	Aug	241
	Sep	168
	Oct	164
	Nov	127
	Dec	103

Year	Month	Generation-MWh
2001	Jan	76
	Feb	113
	Mar	181
	Apr	629
	May	1206
	Jun	1170
	Jul	759
	Aug	225
	Sep	132
	Oct	139
	Nov	337
	Dec	434
2002	Jan	638
	Feb	543
	Mar	761
	Apr	1133
	May	1180
	Jun	829
	Jul	951
	Aug	218
	Sep	147
	Oct	139
	Nov	143
	Dec	400

Upriver Power Project/City of Spokane
Rated Capacity = 16,700 kW
Hours Connected to System = Not Available
Level of Dispatchability = none
Expiration Date = 7/1/2004

Year	Month	Generation-MWh
1998	Jan	6090
	Feb	9035
	Mar	9495
	Apr	9867
	May	9908
	Jun	8178
	Jul	3527
	Aug	1423
	Sep	2178
	Oct	3678
	Nov	4232
	Dec	8602
1999	Jan	10724
	Feb	8703
	Mar	10238
	Apr	9255
	May	8349
	Jun	8383
	Jul	6266
	Aug	2520
	Sep	2417
	Oct	3467
	Nov	4844
	Dec	9988
2000	Jan	7597
	Feb	9352
	Mar	10715
	Apr	7098
	May	8327
	Jun	9501
	Jul	3620
	Aug	1170
	Sep	2341
	Oct	4239
	Nov	3914
	Dec	3245

Year	Month	Generation-MWh
2001	Jan	1871
	Feb	1918
	Mar	3900
	Apr	7329
	May	10071
	Jun	5661
	Jul	1758
	Aug	452
	Sep	994
	Oct	3072
	Nov	3832
	Dec	7159
	Jan	9274
	Feb	7793
	Mar	10929
	Apr	7410
	May	7295
	Jun	7427
	Jul	5753
	Aug	1374
	Sep	2127
	Oct	3589
	Nov	2615
	Dec	3648

Meyers Falls/Hydro Technology Systems
Rated Capacity = 1300 kW
Hours Connected to System = Not Available
Level of Dispatchability = none
Avista sold the plant to Hydro Technology on 2/12/99
Expiration Date = 12/31/2006

Year	Month	Generation-MWh
1999	Jan	0
	Feb	0
	Mar	439
	Apr	829
	May	825
	Jun	871
	Jul	834
	Aug	877
	Sep	826
	Oct	757
	Nov	819
	Dec	877
2000	Jan	1603
	Feb	929
	Mar	198
	Apr	914
	May	884
	Jun	941
	Jul	914
	Aug	891
	Sep	572
	Oct	575
	Nov	757
	Dec	834

Year	Month	Generation-MWh
2001	Jan	817
	Feb	865
	Mar	773
	Apr	947
	May	916
	Jun	945
	Jul	791
	Aug	251
	Sep	75
	Oct	165
	Nov	378
	Dec	562
2002	Jan	841
	Feb	911
	Mar	870
	Apr	959
	May	913
	Jun	949
	Jul	925
	Aug	618
	Sep	259
	Oct	288
	Nov	439
	Dec	610

PURPA Thermal Plants

Minnesota Methane/MM Spokane Energy LLL
Rated Capacity = 900 kW
Hours Connected to system = Not Available
Level of Dispatchability = none
Expiration Date = 4/03/2016

Year	Month	Generation-MWh	Year	Month	Generation-MWh
1998	Jan	0	2001	Jan	406
	Feb	0		Feb	232
	Mar	0		Mar	348
	Apr	0		Apr	432
	May	0		May	242
	Jun	228		Jun	340
	Jul	454		Jul	241
	Aug	417		Aug	173
	Sep	420		Sep	230
	Oct	417		Oct	359
	Nov	529		Nov	366
	Dec	496		Dec	314
1999	Jan	379	2002	Jan	388
	Feb	256		Feb	186
	Mar	418		Mar	277
	Apr	411		Apr	374
	May	515		May	402
	Jun	433		Jun	327
	Jul	482		Jul	336
	Aug	456		Aug	257
	Sep	472		Sep	257
	Oct	473		Oct	246
	Nov	457		Nov	288
	Dec	473		Dec	325
2000	Jan	320			
	Feb	413			
	Mar	393			
	Apr	496			
	May	427			
	Jun	485			
	Jul	412			
	Aug	490			
	Sep	459			
	Oct	454			
	Nov	494			
	Dec	367			

Appendix

O

Avoided Cost Details

Administrative avoided costs, as opposed to those developed with a model, are determined by a public utility commission process that is intended to represent the costs a utility would otherwise incur to generate or purchase power if not acquired from another source. These costs would apply to customer owned resources made available to the Company.

In general, avoided costs are meant to represent the incremental cost of new electric resources available to a utility. Avoided cost rates reflect the price of power from the avoided resource or resource mix. These rates are often applied to the purchase of energy from PURPA qualifying facilities (QF). In some cases, the avoided cost is used to determine the cost-effectiveness of potential resource alternatives.

Presently, the avoided cost methodology used in the filed tariff for the purchase of qualifying facilities output is very different as determined in the two states of Washington and Idaho. In Washington the avoided cost schedule provides baseline payments for QFs under one megawatt. These standard firm energy rates are based on projected monthly market prices capped at the cost of a gas-fired CCCT. The annual rates in $/MWh for the next four years are as follows:

- 2004 – $33.11
- 2005 – $33.67
- 2006 – $33.79
- 2007 – $35.50

For QFs over one megawatt, the WUTC has in place a bidding system that allows the company to compare the value of a QF to other resource alternatives.

In Idaho the avoided cost schedule is for QFs under ten megawatts. The IPUC assumes that there are no future surplus periods for the utilities and the avoided resource of choice is a gas-fired CCCT. The non-levelized rates in $/MWh for the next four years are as follows:

- 2004 – $41.35
- 2005 – $42.39
- 2006 – $43.45
- 2007 – $44.54

For QFs over ten megawatts, the IPUC methodology uses the company's IRP in determining the rate to be paid a QF. The methodology is based on the preferred resource plan as found in the current IRP report.

Appendix

P

NWPPC Assumptions

The following text contains assumptions from the Northwest Power Planning Council (NWPPC) regarding new resources. This data comes directly from the most recent draft of the forthcoming NWPPC Fifth Power Plan.

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Northwest Power Planning Council
New Resource Characterization for the Fifth Power Plan

Natural Gas Simple-Cycle Gas Turbine Power Plants

May 20, 2002

This paper describes the technical characteristics and cost and performance assumptions to be used by the Northwest Power Planning Council for assessments involving new natural gas simple-cycle gas turbine power plants. The intent is to characterize a typical facility, recognizing that actual facilities will differ from these assumptions in the particulars. We anticipate using these assumptions in our price forecasting and system reliability models. The assumptions may also be used in analyzing the issue of maintaining adequate system reliability. Others may use the Council's technology characterizations for their own purposes.

Gas ("combustion") turbine power plants are based on aircraft jet engine technology. A gas turbine power plant consists of a gas compressor, fuel combustors and a gas expansion turbine. Air is compressed in the gas compressor. Energy is added to the compressed air by combusting liquid or gaseous fuel in the combustor. The hot, compressed air is expanded through the gas turbine. The gas turbine drives both the compressor and an electric power generator. Gas turbine power plants are available as heavy-duty "frame" machines specifically designed as stationary engines, or as aeroderivative machines - aircraft engines adapted to stationary applications. Aeroderivative machines tend to be more thermally efficient than frame machines, but more costly to purchase and operate. Stationary gas turbine technology development is strongly driven by gas turbine applications in the military and aerospace industries.

The principal environmental concerns associated with simple-cycle gas turbines have been emissions of nitrogen oxides (NOx) and carbon monoxide (CO). Noise has been a concern at sites near residential and commercial areas. Fuel oil operation may produce sulfur dioxide. Like other fossil fuel power plants, gas turbines produce carbon dioxide. Within the past decade, the commercial introduction of "low-NOx" combustors and high temperature selective catalytic controls for NOx and CO, has enabled the control of NOx and CO emissions from simple-cycle gas turbines to levels comparable to combined-cycle power plants.

Because of the ability of the Northwest hydropower system to supply short-term peaking capacity, simple-cycle gas turbines have been a minor element of the regional power system. As of January 2000, about 900 megawatts of simple-cycle gas turbine capacity was installed in the Northwest, comprising less than 2% of system capacity. The power price excursions, threats of shortages and abnormally poor hydro conditions of 2000 and 2001 sparked a renewed interest in simple-cycle turbines as a hedge against high power prices, shortages and poor water. About 360 megawatts of simple-cycle gas turbine capacity has been installed in the region since 2000, primarily by large industrial consumers exposed to wholesale power prices and by utilities with direct exposure to hydropower uncertainty (including Bonneville slice customers).

The proposed reference plant is generally based on the 47 megawatt (nominal) General Electric LM6000PC Sprint gas turbine generator. Aeroderivative gas turbines such as the LM6000 have been the predominant type of simple-cycle machine installed in response to last year's price excursions, both in the Northwest as well as elsewhere on the western grid. Fuel is assumed to be pipeline natural gas. A firm gas transportation contract with capacity release capability is assumed, in lieu of backup fuel. Air emission controls include water injection plus selective catalytic reduction for NOx control and an oxidation catalyst for CO control. The machine is assumed to be located at an existing gas-fired power plant site and would therefore not require development of site infrastructure.

Issues:

Is the assumption of firm gas transportation in lieu of backup fuel such as fuel oil or propane reasonable?

We are assuming emission control levels comparable to those required of permanently sited simple-cycle units in California. Are these reasonable, or unrealistically stringent for the Northwest? Would capital or O&M costs change significantly with less stringent environmental controls?

The proposed forced outage assumption is much lower than those reported in the Generation Availability Data System. The average age of units represented in the GADS data is greater than 20 years and not believed to be representative of new units. The proposed forced outage assumption is based on monitoring of newer units (LM6000s).

In general, the proposed assumptions are those needed by the Council for its analytical efforts. Is there additional information that might be useful to others that we should include for this and other technologies?

We have not assessed the availability of sites (i.e. potential capacity limits) because earlier capacity addition studies show little development of simple-cycle gas turbines. However, simple-cycle gas turbines may be an economical approach to maintaining system reliability. How should we approach the issue of site availability and infrastructure requirements?

The capital cost estimate is based on a limited number of published cost reports. Can we assume that these "Press release" costs are a reasonable basis for generic capital costs?

Table 1: Resource characterization: Natural gas simple-cycle gas turbine power plants

Facility	Natural gas-fired aeroderivative gas turbine generator set. 47 MW new & clean output @ ISO conditions. Water injection plus SCR for NOx control, CO catalyst for CO control. Single unit at existing power plant site.	Based on GE LM6000 PC Sprint
Fuel	Pipeline natural gas, firm transportation contract with capacity release provisions.	
Technology base year	2000	Fifth plan base year.
Price base year	2000	Fifth plan base year.
Net power output	New & clean: 47.1 MW Lifetime average: 46.6 MW	GE LM6000PC Sprint rating less 2% inlet & exhaust losses. Arbitrary 1% average lifetime degradation.
Lead time	Development: 12 months Construction: 12 months	4th plan values.
Availability	Scheduled outage factor: 6% (21 days/yr) Forced outage rate: 3% Mean time to repair: 80 hours Availability: 91%	Scheduled outage based on 1995 - 99 GADS “Jet Engines” 20+ MW capacity and consistent w/fleet monitoring. FOR based on LM6000 fleet monitoring. MTR based on GADS.
Heat rate (HHV)	New & clean: 9550 Btu/kWh Lifetime average: 9750 Btu/kWh Vintage improvement: -0.6%/yr	GE Aero Energy LM6000, adjusted for inlet & exhaust losses. ISO conditions. Improvement is average for 2000 - 2019 from 4th Plan.
Seasonality	Will provide table of ambient temperature/output factors using historical weather data for three regions.	Existing table needs to be normalized to ISO output needs.
Service life	30 years	4th Power plan.
Capital cost	Development: $2.5 million ($54/kW) Construction (overnight): $680/kW (base) +/- 20%	Development cost based on 4th Plan factors. Construction costs based on published costs from several projects.
Capital replacement	$1.25/kW/yr	Based on a feasibility study supplied to the Council.

Non-fuel O&M cost	Fixed O&M: $13/kW/yr Property Tax: $13/kW/yr Insurance: $2/kW/yr Variable: $32.40/MWh Vintage improvement-0.6%/yr	Based on a feasibility study supplied to the Council except prop tax & insurance. Property tax & insurance are Council's generic values of 1.4% & 0.25% assessed value, respectively. Vintage improvement is 4th Plan forecast average for 2000 - 2019.
Financing	Mix of IPP & Utility	
SOx	Negligible	
NOx	5 ppmv@15% O2	Permanent permit reqmts for recent CA peakers.
CO	6 ppmv@15% O2	Permanent permit reqmts for recent CA peakers.
Particulates	0.01gr/scf	Permanent permit reqmts for recent CA peakers.
CO2	1115 lb/MWh (560 T/Gwh)	Based on EPA "standard" fuel carbon content assumptions.
Site Availability	Not assessed.	

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Northwest Power Planning Council
New Resource Characterization for the Fifth Power Plan

Coal-Fired Power Plants

May 17, 2002

This paper describes the technical characteristics and cost and performance assumptions to be used by the Northwest Power Planning Council for assessments involving new coal-fired power plants. The intent is to characterize a typical facility, recognizing that actual facilities will differ from these assumptions in the particulars. We anticipate using these assumptions in price forecasting and system reliability assessment models. Others may use the Council's technology characterizations for their own purposes.

Coal-fired steam-electric power plants are a mature technology, in use for over a century. Coal-fired power plants are the major source of power in eastern electricity supply systems and the second largest component of the western grid. Currently, over 36,000 megawatts of coal steam-electric power plants are in service on the western electricity grid, comprising about 23% of generating capacity. In recent years, however, the economic and environmental advantages of combined-cycle gas turbines, low load growth and promise of advanced coal-based technologies with superior efficiency and environmental characteristics eclipsed conventional coal-fired steam-electric technology, at least in the United States. Since 1990, less than 500 megawatts of new coal-fired steam electric plant entered service on the western grid.

The future prospects for coal-fired steam-electric power plants may be changing. Like reciprocating internal combustion engines, another mature technology, the economic and environmental characteristics of coal-fired steam-electric power plants have greatly improved. These factors, combined with the prospect of stable or declining coal prices may reinvigorate the competition between coal and natural gas and lessen the near-term prospects for revolutionary coal-based technologies.

The capital cost of coal-fired steam-electric plants has declined about 25% (constant dollars) since the early 1990s with little or no sacrifice to thermal efficiency, reliability or environmental performance. This cost reduction is attributable to plant performance improvements, automation and reliability improvements, equipment cost reduction, reduced construction schedule, and increased market competition (DOE, 1999). Coal prices also have declined during this period as a result of stagnant demand and productivity improvements in mining and transportation. By way of comparison, the Council's 1991 power plan estimated the overnight capital cost of a new coal-fired steam-electric plant to be $1775/kW and the cost of Powder River coal at $0.68/MMBtu (year 2000 dollars). The capital and fuel costs proposed for the Fifth Power Plan are $1468/kW and $0.71/MMBtu, respectively.

Though the economics have improved, other issues associated with future development of coal-fired power plants remain largely unchanged. The issues cited in the Fourth Power Plan - air quality impacts, carbon dioxide and global climate change, water impacts, solid waste, site availability, coal transportation, electric power transmission and impacts of coal mining and transportation - remain significant.

The proposed reference plant is a subcritical 400 megawatt pulverized coal-fired unit. It is one of two or more co-located similar units. Because of increasing constraints on the availability of water, we assume the plant is equipped with dry mechanical draft cooling. The plant would be equipped with flue gas desulfurization, fabric filter particulate control and would use combustion NOx control. In view of cost and performance improvements achieved in recent years with conventional technology, the potential for further improvements, and difficulties experienced with development of advanced technologies, future improvements in cost and performance is based on evolutionary improvements to conventional technology.

Issues:

- In previous power plans, location-specific coal-fired power plant costs (including transmission interconnection and site infrastructure) were based on actual Northwest sites that had been proposed for development. The availability of capacity for future development was based on the same approach. This approach no longer appears practical now that power price forecasting and other Council analyses demand a west-wide view. What approach should the Council use in expanding the basis plant assumptions to the various load-resource areas used in the Council's models? What are the important variables among prospective sites? Do we need to assess possible constraints on resource development?
- What should we assume with respect to future environmental requirements for coal-fired capacity? Will mercury and other air toxins be controlled and how would plant cost and performance be affected? The reference design does not include selective catalytic reduction (SCR) for additional NOx control. Should we assume that SCR would be typically installed on new plants.
- The proposed scheduled outage factor seems high (~30 days/yr) but is consistent with GADS data and new plant design objectives. Do this assumption require revision?
- Our current assumption regarding future technology development is limited to heat rate improvement and is taken from the Energy Information Administration *Annual Energy Outlook 2002*. The basis is unclear. Should we look at an alternative approach, e.g. adoption of some advanced technology or achievement of US DOE performance goals by some future date?
- Capital replacement assumptions affect the retirement of existing capacity in power price forecasting and other modeling. Are the proposed assumptions realistic?

References

DOE (1999): US Department of Energy. *Market-based Advanced Coal Power Systems*. March 1999.

EIA (2001): US Department of Energy, Energy Information Administration. *Assumptions to the Annual Energy Outlook 2002*. December 2001.

Table 1: Resource characterization: Coal-fired power plants

Facility	400 MW (nominal) pulverized coal-fired subcritical steam-electric plant, 2400 psig/1000^{o}F/1000^{o}F reheat. Dry mechanical draft cooling. Low-NOx burners; lime spray dryer; fabric particulate filter. "Reference plant" design. Co-sited with one or more additional units.	Reference plant from DOE, 1999, modified to suit western coal and site conditions.
Fuel	Western subbituminous coal. 9300 Btu/lb, 0.4% S.	Characteristics are for Powder River Basin coal.
Technology base year	2000	Fifth plan base year.
Price base year	2000	Fifth plan base year.
Net power output	New & clean: 385 MW Lifetime average: 374 MW	DOE (1999) Derated 3% for dry cooling. Average degradation based on 4th plan GT values.
Lead time	Development: 36 months Construction: 36 months	Development shortened from 4th plan 48 months.
Availability	Scheduled outage factor: 9% Forced outage rate: 7% Mean time to repair: 40 hours Availability: 85%	Availability factors based on 1995 - 99 GADS, but consistent w/DOE (1999) reduced redundancy design.
Heat rate (HHV)	New & clean: 9350 Btu/kWh Lifetime average: 9550 Btu/kWh Vintage improvement: -0.34%/yr	DOE (1999), increased 3% for dry cooling. Average degradation based on 4th plan GT values. Vintage improvement From EIA (2001)
Service life	30 years	DOE (1999). Reduced from 4th Power plan (40 yrs).
Capital cost	Development: $25/kW Construction (Overnight): $1403/kW Startup: $26/kW Working capital: $14/kW	Development cost factors from 4th Plan. Construction, startup & working capital from DOE (1999) plus estimated dry cooling, land & owner's admin costs. No allowance for site infrastructure.
Capital replacement	To 30 yrs: $15/kW/yr Over 30 yrs: $20/kW/yr	EIA (2001).
Non-fuel O&M cost	Fixed O&M : $25/kW/yr Property Tax: $20/kW/yr	DOE (1999) except prop tax & insurance. Prop tax & insurance 1.4% & 0.25% assessed value,

	Insurance: $4/kW/yr Variable: $0.5/MWh Vintage improvement: 0%/yr	respectively.
Financing	IPP	See Table 2 (To follow)
SOx	Calculation to be supplied	95% removal
NOx	4.09 lb/Mwh (2.05 T/GWh)	DOE (1999) Est. 2005 BACT
Particulates	0.272 lb/Mwh (0.136 T/GWh)	DOE (1999) Est. 2005 BACT
CO2	Calculation to be supplied	
Site Availability	The current AURORA run (with no limits on new capacity) result in the following build levels by 2020: AB - 700 MW, CO 1750 MW, ID 3150 MW, MT 350 MW, WY 1140 MW.	

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Northwest Power Planning Council
New Resource Characterization for the Fifth Power Plan

Natural Gas Combined-Cycle Gas Turbine Power Plants

August 27, 2002

This paper describes the technical characteristics and cost and performance assumptions to be used by the Northwest Power Planning Council for new natural gas combined-cycle gas turbine power plants. The intent is to characterize a facility typical of those likely to be constructed in the Western Electricity Coordinating Council (WECC) region over the next several years, recognizing that each plant is unique and that actual projects may differ from these assumptions. These assumptions will be used in our price forecasting and system reliability models and in the Council's periodic assessments of system reliability. The Council may also use these assumptions in the assessment of other issues where generic information concerning natural gas combined-cycle power plants is needed. Others may use the Council's technology characterizations for their own purposes.

A combined-cycle gas turbine power plant consists of one or more gas turbine generators equipped with heat recovery steam generators to capture heat from the gas turbine exhaust. Steam produced in the heat recovery steam generators powers a steam turbine generator to produce additional electric power. Use of the otherwise wasted heat in the turbine exhaust gas results in high thermal efficiency compared to other combustion-based technologies. Combined-cycle plants currently entering service can convert about 50 percent of the chemical energy of natural gas into electricity (HHV basis[2]). Additional efficiency can be gained in combined heat and power (CHP) applications (cogeneration), by bleeding steam from the steam generator, steam turbine or turbine exhaust to serve direct thermal loads[3].

A single-train combined-cycle plant consists of one gas turbine generator, a heat recovery steam generator (HSRG) and a steam turbine generator ("1 x 1" configuration). Using "FA-class" combustion turbines - the most common technology in use for large combined-cycle plants - this configuration can produce about 270 megawatts of capacity at reference ISO conditions[4]. Increasingly common are plants using two or even three gas turbine generators and heat recovery steam generators feeding a single, proportionally larger steam turbine generator. Larger plant sizes result in economies of scale for construction and operation, and designs using multiple

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[2] The energy content of natural gas can be expressed on a higher heating value or lower heating value basis. Higher heating value includes the heat of vaporization of water formed as a product of combustion, whereas lower heating value does not. While it is customary for manufacturers to rate equipment on a lower heating value basis, fuel is generally purchased on the basis of higher heating value. Higher heating value is used as a convention in Council documents unless otherwise stated.

[3] Though increasing overall thermal efficiency, steam bleed for CHP applications will reduce the electrical output of the plant.

[4] International Organization for Standardization reference ambient conditions: 14.7 psia, 59^{o} F, 60% relative humidity.

combustion turbines provide improved part-load efficiency. A 2 x 1 configuration using FA-class technology will produce about 540 megawatts of capacity at ISO conditions. Other plant components include a switchyard for electrical interconnection, cooling towers for cooling the steam turbine condenser, a water treatment facility and control and maintenance facilities.

Additional peaking capacity can be obtained by use of various power augmentation features, including inlet air chilling and duct firing (direct combustion of natural gas in the heat recovery steam generator). For example, an additional 20 to 50 megawatts can be gained from a single-train plant by use of duct firing. Though the incremental thermal efficiency of duct firing is lower than that of the base combined-cycle plant, the incremental cost is low and the additional electrical output can be valuable during peak load periods.

Gas turbines can operate on either gaseous or liquid fuels. Pipeline natural gas is the fuel of choice because of historically low and relatively stable prices, deliverability and low air emissions. Distillate fuel oil can be used as a backup fuel, however, its use for this purpose has become less common in recent years because of additional emissions of sulfur oxides, deleterious effects on catalysts for the control of nitrogen oxides and carbon monoxide, the periodic testing required to ensure proper operation on fuel oil and increased turbine maintenance associated with fuel oil operation. It is now more common to ensure fuel availability by securing firm gas transportation.

The principal environmental concerns associated with gas-fired combined-cycle gas turbines are emissions of nitrogen oxides (NOx) and carbon monoxide (CO). Fuel oil operation may produce sulfur dioxide. Nitrogen oxide abatement is accomplished by use of “dry low-NOx” combustors and a selective catalytic reduction system within the HSRG. Limited quantities of ammonia are released by operation of the NOx SCR system. CO emissions are typically controlled by use of an oxidation catalyst within the HSRG. No special controls for particulates and sulfur oxides are used since only trace amounts are produced when operating on natural gas. Fairly significant quantities of water are required for cooling the steam condenser and may be an issue in arid areas. Water consumption can be reduced by use of dry (closed-cycle) cooling, though with cost and efficiency penalties. Gas-fired combined-cycle plants produce less carbon dioxide per unit energy output than other fossil fuel technologies because of the relatively high thermal efficiency of the technology and the high hydrogen-carbon ratio of methane (the primary constituent of natural gas).

Because of high thermal efficiency, low initial cost, high reliability, relatively low gas prices and low air emissions, combined-cycle gas turbines have been the new resource of choice for bulk power generation for well over a decade. Other attractive features include significant operational flexibility, the availability of relatively inexpensive power augmentation for peak period operation and relatively low carbon dioxide production. Combined-cycle power plants are an increasingly important element of the Northwest power system, comprising about 87 percent of generating capacity currently under construction. Completion of plants under construction will increase the fraction of gas-fired combined-cycle capacity from 6 to about 11 percent of total regional generating capacity.

Proximity to natural gas mainlines and high voltage transmission is the key factor affecting the siting of new combined-cycle plants. Secondary factors include water availability, ambient air quality and elevation. Initial development during the current construction cycle was located largely in eastern Washington and Oregon with particular focus on the Hermiston, Oregon crossing of the two major regional gas pipelines. Development activity has shifted to the I-5 corridor, perhaps as a response to east-west transmission constraints and improving air emission controls.

Issues associated with the development of additional combined-cycle capacity include uncertainties regarding the continued availability and price of natural gas, volatility of natural gas prices, water consumption and carbon dioxide production. A secondary issue has been the ecological and aesthetic impacts of natural gas exploration and production. Though there is some evidence of a decline in the productivity of North American gas fields, the continental supply appears adequate to meet needs at reasonable price for at least the 20-year period of the Council's power plan. Importation of liquefied natural gas from the abundant resources of the Middle East and the former Soviet states and could enhance North American supplies and cap domestic prices. The Council forecasts that US wellhead gas prices will escalate at an annual rate of about 0.9% (real) over the period 2002 - 21. Though expected to remain low, on average, natural gas prices have demonstrated both significant short-term volatility and longer-term, three to four year price cycles. Both effects are expected to continue. Additional discussion of natural gas availability and price is provided in the Council issue paper Draft Fuel Price Forecasts for the Fifth Power Plan (Document 2002-07). The conclusions of the paper with respect to natural gas prices are summarized in Appendix A of this document.

Water consumption for power plant condenser cooling appears to be an issue of increasing importance in the west. As of this writing, water permits for two proposed combined-cycle projects in northern Idaho have been recently denied, and the water requirement of a proposed central Oregon project is highly controversial. Significant reduction in plant water consumption can be achieved by the use of closed-cycle (dry) cooling, but at a cost and performance penalty. Over time it appears likely that an increasing number of new combined-cycle projects will use dry cooling.

Carbon dioxide, a greenhouse gas, is an unavoidable product of combustion of any power generation technology using fossil fuel. The carbon dioxide production of a gas-fired combined-cycle plant on a unit output basis is much lower than that of other fossil fuel technologies. The reference plant, described below, would produce about 0.8 lb CO_2 per kilowatt-hour output, whereas a new coal-fired power plant would produce about 2 lb CO_2 per kilowatt-hour. To the extent that new combined-cycle plants substitute for existing coal capacity, they can substantially reduce average per-kilowatt-hour CO_2 production.

The proposed reference plant is based on the General Electric 7FA gas turbine generator in 2 x 1 combined-cycle configuration. The baseload capacity is 540 megawatts and the plant includes an additional 70 MW of power augmentation using duct burners. The plant is fuelled with pipeline natural gas using a firm gas transportation contract with capacity release provision. No backup fuel is provided. Air emission controls include dry low-NOx combustors and selective catalytic reduction for NOx control and an oxidation catalyst for CO and VOC control.

Condenser cooling is wet mechanical draft. Specific characteristics of the reference plant are shown in Table 1.

Table 1
Resource characterization: Natural gas combined-cycle gas turbine power plant
(2002 Dollars)

Facility description and basic assumptions		
Facility	Natural gas-fired combined-cycle gas turbine power plant. 2 GT x 1 ST configuration. 7FA gas turbine technology. 540 MW new & clean baseload output @ ISO conditions, plus 70 MW of capacity augmentation (duct-firing). No cogeneration load. Dry SCR for NOx control, CO catalyst for CO control. Wet mechanical draft cooling.	
Fuel	Pipeline natural gas. Firm transportation contract with capacity release provisions. Seasonal variation in capacity release value.	See Appendix A for a summary of the gas price forecast and structure.
Project developer	Consumer-owned utility: 5% Investor-owned utility: 5% Independent power producer: 90%	See Appendix B for project financing assumptions.
Technology base year	2002	Representative of projects entering service in 2002.
Price base year	2000	5^{th} Plan price year.
Lead time	Development: 24 months Construction: 24 months	
Service life	30 years	

Technical Performance		
Net power	New & clean: 540 MW (baseload), 610 MW (peak) Lifetime average: 528 MW (baseload), 597 MW (peak)	Lifetime average based on 1 % degradation per year, 98.75% recovery at hot gas path inspection or major overhaul. GE data.
Operating limits	Minimum load: 40 %. Cold start: 3 hours Ramp rate: 7 %/min	Minimum load: One GT in service, point of minimum constant firing temperature operation.
Scheduled outages	Scheduled outage factor: 5% (18 days/yr).	Based on a planned maintenance schedule of a 7-day annual inspection, a 10-day hot gas path inspection & overhaul every third year and a 28-day major overhaul every sixth year. Planned maintenance intervals are GE baseline recommendations for baseload service. In addition, assumes two additional 28-day scheduled outages and one six-month plant rebuild during the 30-year plant life.
Forced outages	Forced outage rate: 5% Mean time to repair: 24 hours	NERC Generating Availability Data System (GADS) weighted average equivalent forced outage rate for combined-cycle plants. Mean time to repair is GADS average for full outages.
Availability (lifetime average, busbar)	90%	(1-SOR)*(1-FOR). Derate additional 2.2% if using new & clean capacity.
Heat rate (HHV, net, ISO conditions)	New & clean (Btu/kWh): 6880 (baseload); 9290 (incremental duct firing); 7180 (full power) Lifetime average (Btu/kWh): 7030 (baseload); 9500 (incremental duct firing); 7340 (full power)	Baseload is current new & clean rating for GE 207FA. Lifetime average is new & clean value derated by 2.2%. Degradation estimates are from GE. Duct firing heat rate is GRAC recommendation.
Future technical improvement	2002-21 annual average: -0.6%.	Assume 7B technology full

(expressed as improvement in thermal efficiency)		commercial by 2005; 7H by 2010; asymptotic to ultimate potential by 2060.
Seasonal power output (ambient air temperature sensitivity)	Seasonal power output factors for selected WECC locations are shown in Figure 1.	Based on power output ambient temperature curve for GE STAG combined-cycle plant using 30-year monthly average temperatures.
Elevation adjustment for power output	See Table 2 for power output elevation correction factors for selected WECC locations.	Based on standard gas turbine altitude correction curve.

Costs		
Development & construction	Baseload configuration: $565/kW (overnight); 621 $/kW (all-in). Power augmentation configuration: $525/kW (overnight); 577 $/kW (all-in).	Excludes financing fees and interest during construction. Assumes "equilibrium" market conditions. Normalized cost of a 1x1 plant estimated to be 110% of example plant costs. Incremental cost of power augmentation using duct burners $225/kW. Values are based on new and clean rating.
Development & construction cash flow (%/yr)	3%/97%	
Capital replacement	$1.60/kW/yr[1]	Levelized equivalent of 10% of initial capital investment in Year 15. Value is based on new and clean rating.
Fixed operating costs	Baseload configuration: $7.25/kW/yr. Power augmentation configuration: $6.50/kW/yr.	Includes operating labor, routine maintenance, general & overhead, fees, contingency and an allowance for startup costs and average sales tax. Excludes property taxes and insurance (separately calculated in the Council's models). Normalized fixed O&M cost for a 1x1 plant estimated to be 167% of that for the example 2x1plant. Values are based on new

		and clean rating.
Variable operating costs	$2.80/MWh	Includes consumables, SCR catalyst replacement, makeup water and wastewater disposal costs, long-term major equipment service agreement, contingency and an allowance for sales tax. Excludes any greenhouse gas fees.
Interconnection and regional transmission costs	$15.00/kW/yr	Bonneville point-to-point transmission rate (PTP-02) plus Scheduling, System Control and Dispatch, and Reactive Supply and Voltage Control ancillary services, rounded. Omit for busbar calculations. Value is based on new and clean rating.
Regional transmission losses	1.9%	BPA contractual line losses. Omit for busbar calculations.
Vintage cost reduction	2002-21 annual average: -0.6% (capital and fixed O&M costs)	Assumes cost reductions related to increase in gas turbine specific work by factor of 0.3. Assumes 7B technology full commercial by 2005; 7H by 2010; asymptotic to ultimate potential by 2060.

Emissions (Plant site, excluding gas production & delivery)		
Particulates (PM-10)		Typical permit limits, baseload operation: 0.02 T/GWh
SOx	Typical actual: 0.002 T/GWh	Typical permit limits, baseload operation: 0.02 T/GWh
NOx	Typical actual: 0.039 T/GWh	Typical permit limits, baseload operation: 0.04 T/GWh
CO	Typical actual: 0.005 T/GWh	Typical permit limits, baseload operation: 0.04 T/GWh
Hydrocarbons/VOC	Typical actual: 0.0003 T/GWh	Typical permit limits, baseload operation: 0.01 T/GWh
Ammonia	Typical actual: 0.0000006 T/GWh	Slip from catalyst. Typical permit limits, baseload operation: 0.004 T/GWh
CO_2	411 T/GWh (baseload operation) 429 T/GWh (full power operation)	Based on EPA standard fuel carbon content assumptions and lifecycle average heat rates.
Availability for future development		
Site Availability 2001 - 2020	Initially not limited.	Extent of future development to be tested in AURORA runs. If the resulting development significantly exceeds the inventory of currently or likely permitted sites in any load-resource area this issue will be revisited.

Figure 1
Gas turbine combined-cycle average monthly power output temperature correction factors for selected locations
(relative to ISO conditions)

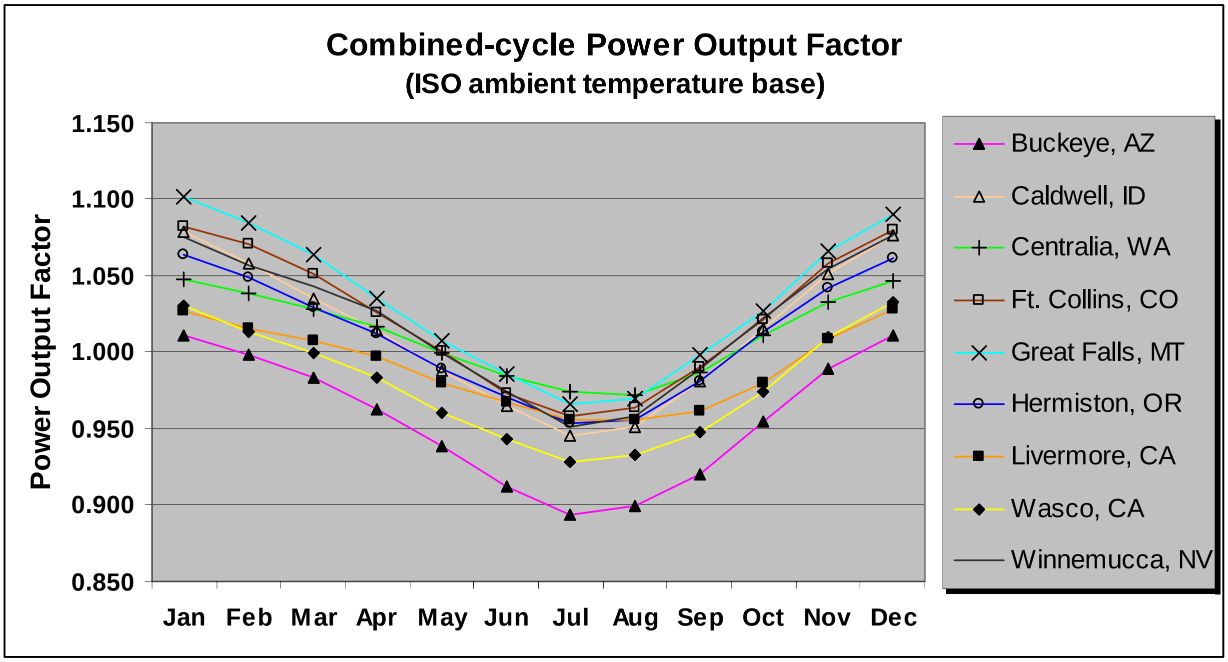


Table 2
Gas turbine power output elevation correction factors for selected locations

Location	Elevation (ft)	Power Output Factor
Buckeye, AZ (nr. Palo Verde)	890	0.972
Caldwell, ID	2370	0.923
Centralia, WA	185	0.995
Ft. Collins, CO	5004	0.836
Great Falls, MT	3663	0.880
Hermiston, OR	640	0.980
Livermore, CA	480	0.985
Wasco, CA (nr. Kern County plants)	345	0.990
Winnemucca, NV	4298	0.859

REVISED DRAFT

Northwest Power Planning Council
New Resource Characterization for the Fifth Power Plan

Wind Power Plants

July 23, 2002

This paper describes the technical characteristics and cost and performance assumptions to be used by the Northwest Power Planning Council for new wind power plants. The intent is to characterize a typical facility, recognizing that actual facilities may differ from these assumptions. This is particularly true of wind power projects. Costs are sensitive to location and size of a wind farm and energy production is sensitive to the quality of the wind resource. In addition, the value of energy from a site is a function of the seasonal and daily variations of the wind. The assumptions that follow will be used in our price forecasting and system reliability models and in the Council's periodic assessments of system reliability. The Council may also use these assumptions in the assessment of other issues where generic information concerning wind power plants is needed. Others may use the Council's technology characterizations for their own purposes.

Wind energy is converted to electricity by wind turbine generators - electric generators driven by rotating airfoils. Because of the low energy density of wind, bulk electricity production from windpower requires tens or hundreds of wind turbine generators arrayed in a wind power plant. A wind power plant (often called a "wind farm") includes meteorological towers, strings of wind turbine generators, turbine service roads, a control system interconnecting individual turbines with a central control station (often remote), a voltage transformation and transmission system connecting the individual turbines to a central substation, a substation to step up voltage for long-distance transmission and an electrical interconnection to the main transmission grid.

The typical wind turbine generator being installed in commercial-scale projects is a horizontal axis machine of 600 to 1500 kilowatts rated capacity with a three-bladed rotor 150 to 250 feet in diameter. The machines are mounted on tubular towers ranging to about 260 feet height. Trends in machine design include improved airfoils; larger machines; taller towers and improved controls. Improved airfoils increase energy capture. Larger machines provide economies of manufacturing, installation and operation. Because wind speed generally increases with elevation above the surface, taller towers and larger machines intercept more energy. Turbine size has increased rapidly in recent years and multi-megawatt (2000 - 2750kW) machines are being introduced. These machines are likely to see initial service in European offshore applications.

Many of the issues that formerly impeded the development of wind power have been resolved, clearing the way for the significant development occurring in the Northwest in recent years. Concerns regarding avian mortality, aesthetic and cultural impacts have been alleviated by the choice of dryland agricultural areas for project development. The resulting land rent revenue has also garnered political support from the agricultural community. Though per-kilowatt installed costs appear not to have greatly declined, turbine performance, turbine reliability and siting has improved, increasing energy capture thereby reducing energy production costs. A robust market for “green” power has developed in recent years, driven by retail green power options, utility efforts to diversify and “green up” resource portfolios, green power acquisition mandates imposed by public utility commissions as a condition of utility acquisitions, and system benefits funds established in conjunction with industry restructuring. Equally important, the federal production tax incentive has been extended, though with some interruption.

In spite of the recent unprecedented development of windpower, issues affecting continued development of the resource remain. As of this writing, wholesale power costs are low and are anticipated to remain so for several years. The cost of firming and shaping wind farm output to serve load are not well understood and can be substantial. While it appears possible that several hundred megawatts of wind power can be shaped at relatively low cost using the Northwest hydropower system, the cost of firming and shaping additional amounts of wind energy are uncertain, pending further operating experience and analysis. Wind power, because of its intermittency, has been subject to generation imbalance penalties intended to constrain gaming by operators of schedulable thermal resources. The Bonneville Administrator has just signed a Record of Decision exempting wind power from imbalance penalties for a period of one year. The issue has received considerable publicity and is likely to be addressed in federal energy legislation and discussions of future transmission management. Northwest wind development to date has not required expansion of transmission capacity, which can be expensive for wind because of its relatively low capacity factor. However, the availability of prime sites with easily accessible surplus transmission capacity is limited. Finally, the competitive position of wind power remains dependent upon the federal production tax credit.

The first commercial-scale wind plant in the Northwest using contemporary technology is the 25 MW Vansycle project in Umatilla County, Oregon. Since Vansycle entered service in late 1998, four additional windfarms have been placed in service or are under construction. Now in operation or under construction within the region are 412 megawatts of wind capacity, producing about 130 average megawatts of energy. In addition, Northwest utilities have contracted for 110 megawatts of capacity, producing about 44 megawatts of energy from two Wyoming projects. Northwest wind farms range in size from 25 to 265 megawatts, and are comprised of 16 to nearly 400 machines ranging in size from 600 to 1500 kW. Several of these sites are capable of significant expansion and additional sites have been proposed for development.

Four geographically-based generic resource types are used in modeling future wind resources:

- Basin & Range: Favorably-oriented ridges in the basin and range geographic province ranging from Oregon and Idaho south to Arizona.

- Cascades and Inland: Favorably-oriented ridges lying within and east of the Columbia River Gorge and other Cascades features that channel westerly winds.

- Northern California: California north of the Path 15 transmission constraint. Temperature-driven winds with a strong summer peak and strong diurnal shape.

- Northwest Coast: Coastal sites with storm-driven wind patterns.

- Rockies & Plains: Areas within and east of Rocky Mountain features that channel prevailing westerly winds. Storm-driven winds with a strong winter-peaking shape.

- Southern California: California south of the Path 15 transmission constraint. Temperature-driven winds with a strong summer peak and strong diurnal shape.

References:

DWIA (2002): Danish Wind Industry Association, *Guided tour on Wind Energy ,* www.windpower.org.

EPRI (1997): Electric Power Research Institute, *Renewable Energy Technology Characterizations (EPRI TR-1094496)*. December, 1997.

Table 1
Resource characterization: Wind power plants

Facility description and basic assumptions		
Facility	50 MW central-station wind power project. Five resource types are modeled, varying by wind quality and seasonal and daily wind characteristics. The resource types and WECC areas for which they are used in the Council's work are: Basin & Range - S. ID, NV, UT, AZ Cascades & Inland - E. WA & OR, N. ID Northern California - N. CA Northwest Coast - W. WA & OR Rockies & Plains - AB, MT, WY, CO, NM Southern California - S. CA & Baja	Typical projects may range from 25 to 300 MW.
Technology base year	2002 vintage design	
Price base year	2000	5^{th} Plan price year.
Lead time	Development: 24 months Construction: 12 months	
Service life	20 years	Typical design life for Danish wind turbine generators (DWIA, 2002).

Technical Performance		
Net power	50 MW	Assumed to include in-farm losses.
Scheduled outages	Included in capacity factor.	
Forced outages	Included in capacity factor.	
Capacity Factor (net)	Basin & Range - 28 % Cascades & Inland - 30% Northern California - 34 % Northwest Coast - 30% Rockies & Plains - 39 % Southern California - 34 %	Power delivered to transmission interconnection. Net of in-farm losses and outages.
Vintage performance improvement	2002-21 average annual: 0.0 %.	Performance improvement is modeled as estimated vintage cost reduction (below).
Seasonal pattern	Table 2 and Figure 1	
Diurnal pattern	California - Table 3 and Figure 3, other areas - no diurnal pattern.	

Costs		
Development & construction	$1060/kW (overnight); $1100/kW (typical all-in)	Includes project development, turbines, site improvements, erection, substation, startup costs & working capital. "Overnight" cost excludes interest during construction. Range: $1120/kW for 25 MW project to $930/kW for 300 MW project (overnight).
Capital replacement	$2.50/kW/yr (levelized)	Gearbox overhaul and generator bearing replacement at year 10 at 5% of installed cost ($57/kW). EPRI (1997).
Fixed operating costs	$14.00/kW/yr.	Excludes property taxes and insurance (separately calculated in the Council's models), integration and shaping costs and land royalty.
Variable operating costs	$1.00/MWh	Land lease. Approximation of 2.5% of forecast wholesale power costs (EPRI 1997). Also typical of per-kWh payment agreements.
Interconnection and regional transmission costs	$15.00/kW/yr	Bonneville point-to-point transmission rate (PTP-02) plus Scheduling, System Control and Dispatch, and Reactive Supply and Voltage Control ancillary services, rounded. Omit for busbar calculations. Bonneville 2002 transmission tariff.
Regional transmission losses	1.9%	BPA contractual line losses. Omit for busbar calculations.
Firming and shaping	$15.00/MWh	
Vintage cost reduction	2002-21annual average: -2.0 %.	Proxy for both cost and performance improvements. Council Fourth Plan estimate based on historical and potential improvements.

Development, financing and capital-related costs		
Financing	80% Independent power producer; 20% consumer-owned utility.	Assumptions provided separately
Tax depreciation	5 years	
Property tax	1.4%/yr of book value.	Average regionwide conditions. Council assumption.
Insurance	0.3%/yr of book value.	
Availability for future development		
Site Availability 2001 - 2020	Initially not limited.	Forecasted extent of future development will be tested in AURORA model runs. If this level significantly exceeds 1000MW in any load-resource area this issue will be revisited.

Table 2
Normalized monthly wind energy distribution

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Basin & Range	1.19	1.39	1.07	1.05	0.94	0.71	0.56	0.61	0.72	0.74	1.59	1.43
Cascades & Inland	1.03	0.90	1.07	1.07	1.21	1.07	1.11	1.07	0.94	0.73	0.85	0.96
Northern California	0.22	0.28	0.69	1.13	1.81	1.88	2.10	1.85	0.96	0.65	0.24	0.18
Northwest Coast	1.19	1.57	1.07	0.86	0.84	0.84	1.01	0.54	0.66	0.80	1.40	1.21
Rockies & Plains	1.61	1.57	1.02	0.84	0.77	0.73	0.35	0.42	0.52	1.00	1.30	1.88
Southern California	0.68	0.66	0.97	1.28	1.75	1.33	1.47	0.95	0.87	0.82	0.65	0.57

Figure 1
Normalized monthly wind energy distribution

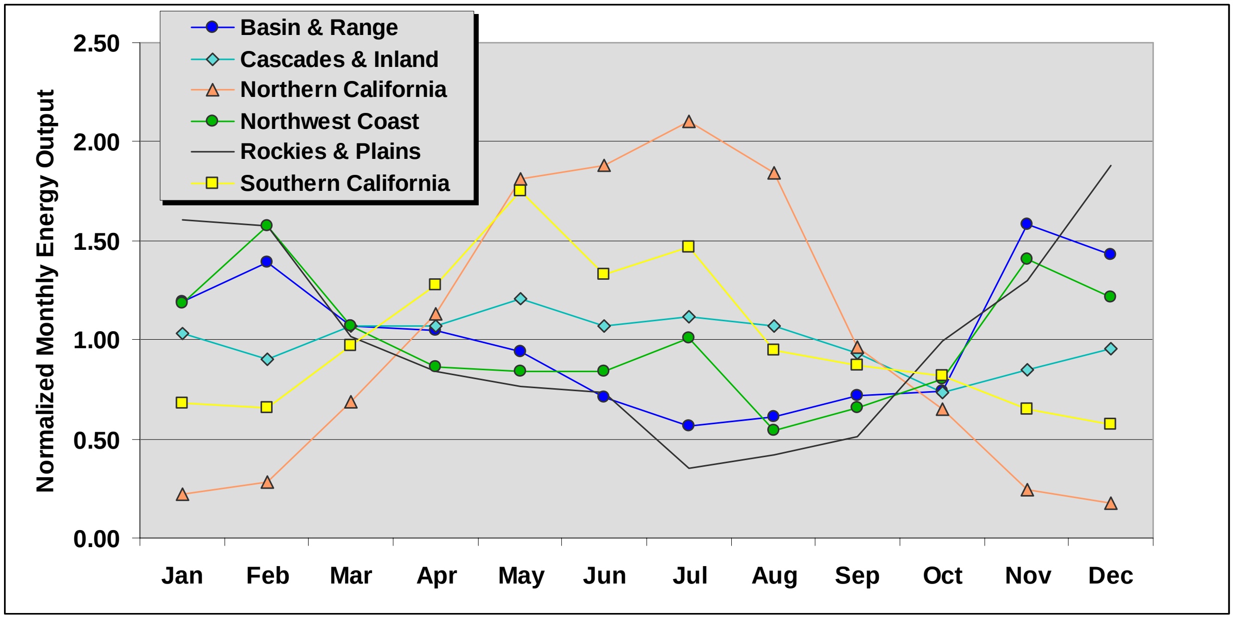
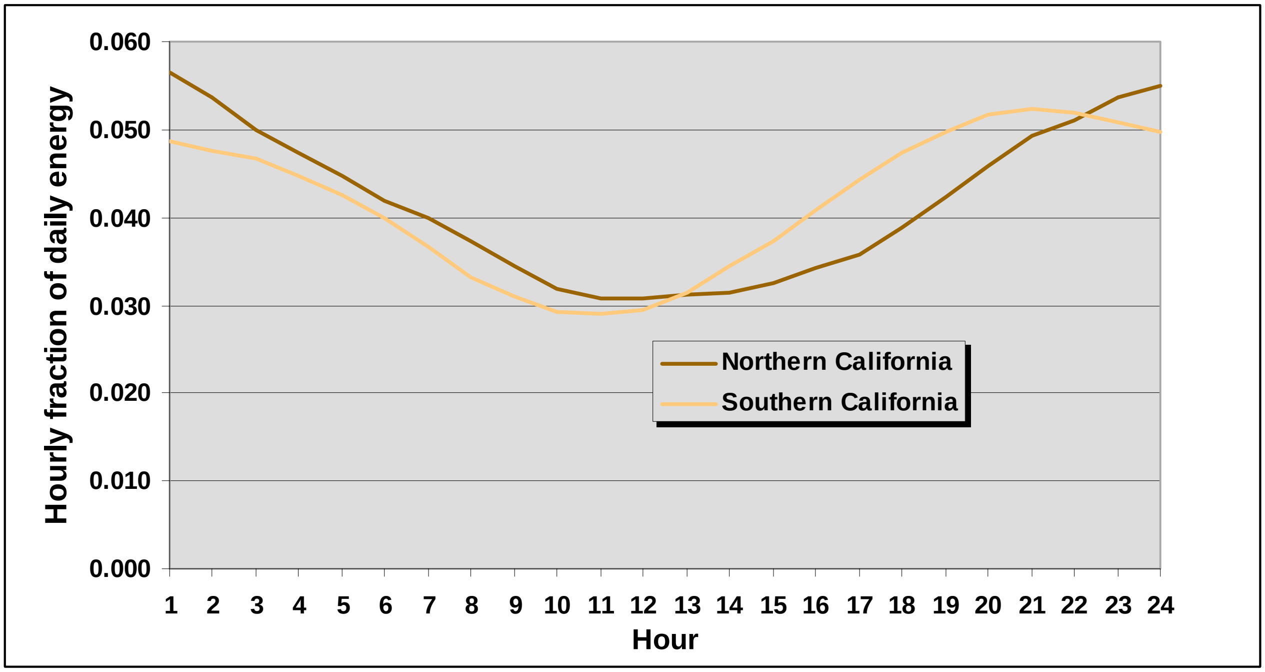


Table 3
Diurnal wind energy distribution
(Hourly fraction of daily energy)

Hour	Northern California	Southern California
1	0.056	0.049
2	0.054	0.048
3	0.050	0.047
4	0.047	0.045
5	0.045	0.043
6	0.042	0.040
7	0.040	0.037
8	0.037	0.033
9	0.034	0.031
10	0.032	0.029
11	0.031	0.029
12	0.031	0.029
13	0.031	0.031
14	0.031	0.034
15	0.033	0.037
16	0.034	0.041
17	0.036	0.044
18	0.039	0.047
19	0.042	0.050
20	0.046	0.052
21	0.049	0.052
22	0.051	0.052
23	0.054	0.051
24	0.055	0.050

Figure 2
Diurnal wind energy distribution



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Appendix

Q DSM Modeling Details

The following table represents input assumptions used in modeling the Company's DSM efforts in AURORA. It includes price, capacity, and energy information for each price tier of the six DSM resources that were developed.

Table Q.1
DSM Resource Assumptions

Price Tier	Measure Component	Utility Cost ($/MWh)	Capacity (kW)	Energy (akW)	Capacity Factor
1	Commercial HVAC	36.12	8935.11	878.45	9.8%
1	Commercial Lighting	13.28	2392.93	1325.47	55.4%
1	Commercial DHW	12.95	40.91	24.80	60.6%
1	Residential HVAC	17.13	540.37	159.82	29.6%
1	Residential Lighting	19.40	5619.69	924.66	16.5%
1	Residential DHW	30.92	14.72	7.81	53.0%
2	Commercial HVAC	45.16	893.51	87.84	9.8%
2	Commercial Lighting	16.59	239.29	132.55	55.4%
2	Commercial DHW	16.19	4.09	2.48	60.6%
2	Residential HVAC	21.41	54.04	15.98	29.6%
2	Residential Lighting	24.25	561.97	92.47	16.5%
2	Residential DHW	38.65	1.47	0.78	53.0%
3	Commercial HVAC	56.44	89.35	8.78	9.8%
3	Commercial Lighting	20.74	23.93	13.25	55.4%
3	Commercial DHW	20.24	0.41	0.25	60.6%
3	Residential HVAC	26.76	5.40	1.60	29.6%
3	Residential Lighting	30.31	56.20	9.25	16.5%
3	Residential DHW	48.31	0.15	0.08	53.0%
4	Commercial HVAC	70.56	8.94	0.88	9.8%
4	Commercial Lighting	25.93	2.39	1.33	55.4%
4	Commercial DHW	25.30	0.04	0.02	60.6%
4	Residential HVAC	33.45	0.54	0.16	29.6%
4	Residential Lighting	37.89	5.62	0.92	16.5%
4	Residential DHW	60.38	0.01	0.01	53.0%

The following charts depict the hourly load shapes for each of the six DSM resources modeled within AURORA. These shapes are designated as the hourly shape for a typical week for a given month. Each month of the year is represented by one of the twelve charts included.

Chart Q.1
January Load Shapes

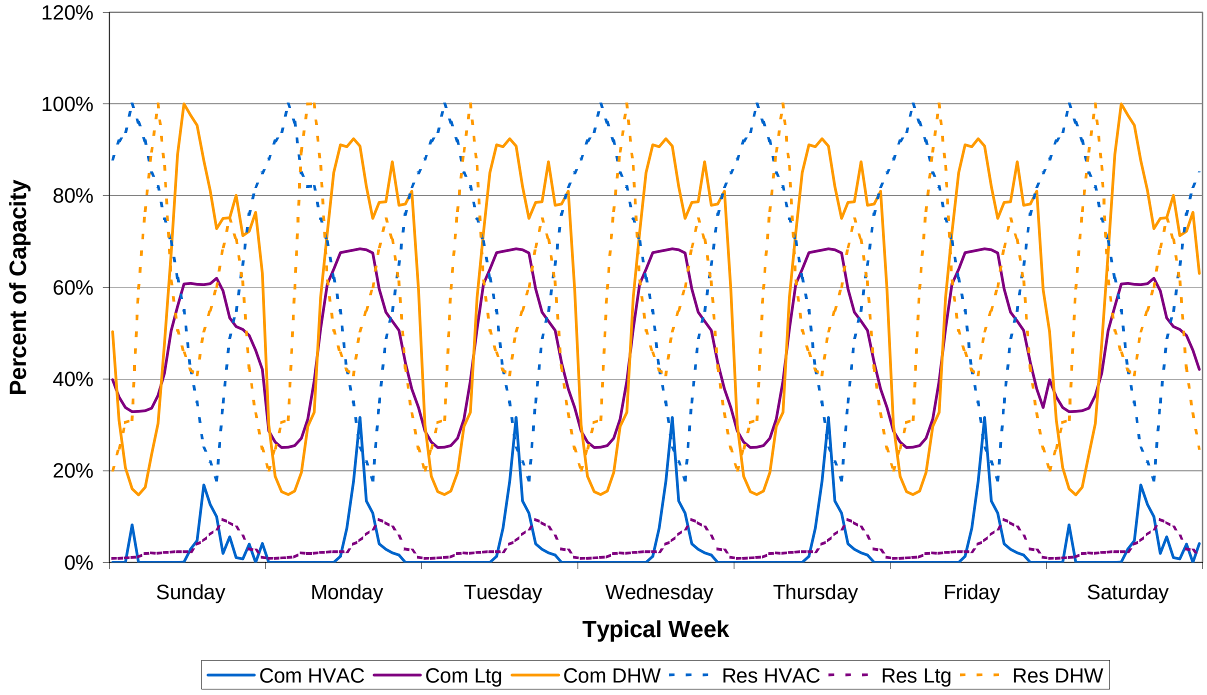

Chart Q.2
February Load Shapes

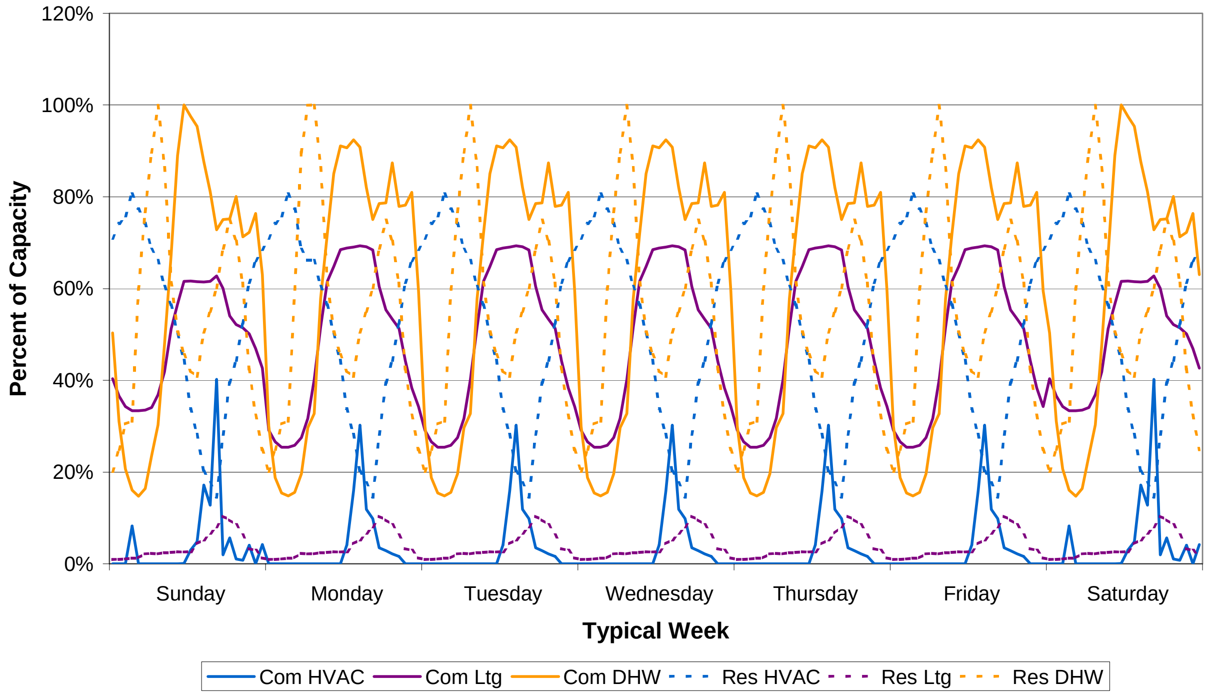

Chart Q.3
March Load Shapes

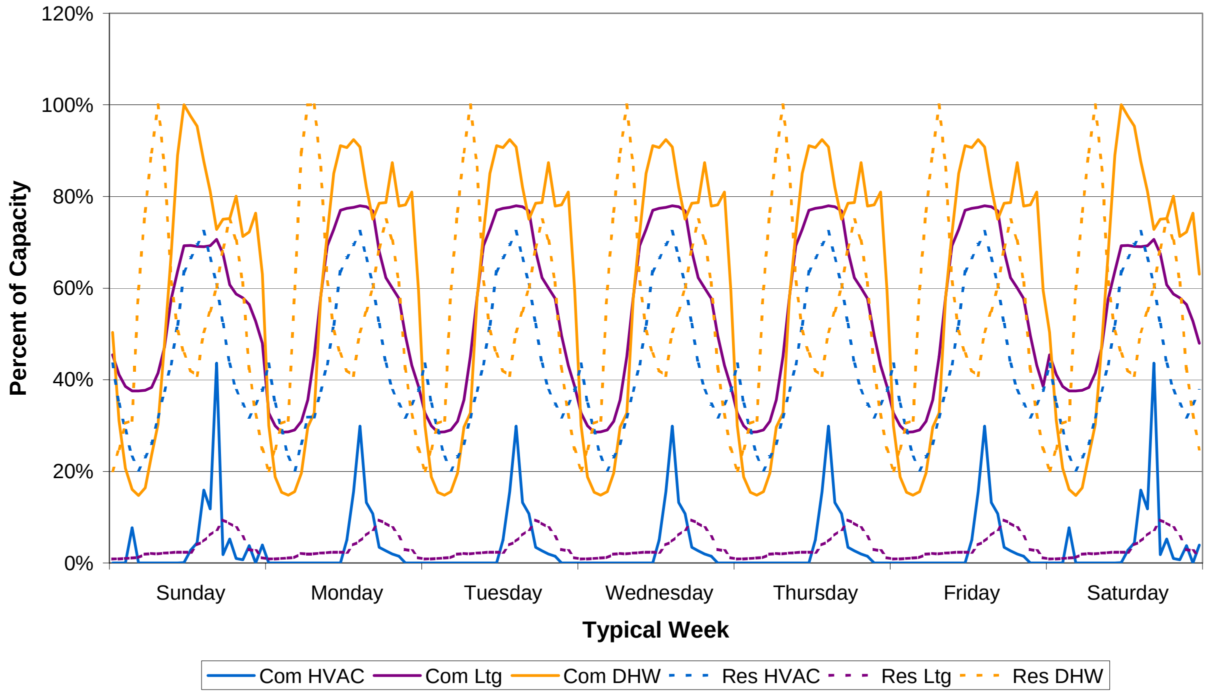

Chart Q.4
April Load Shapes

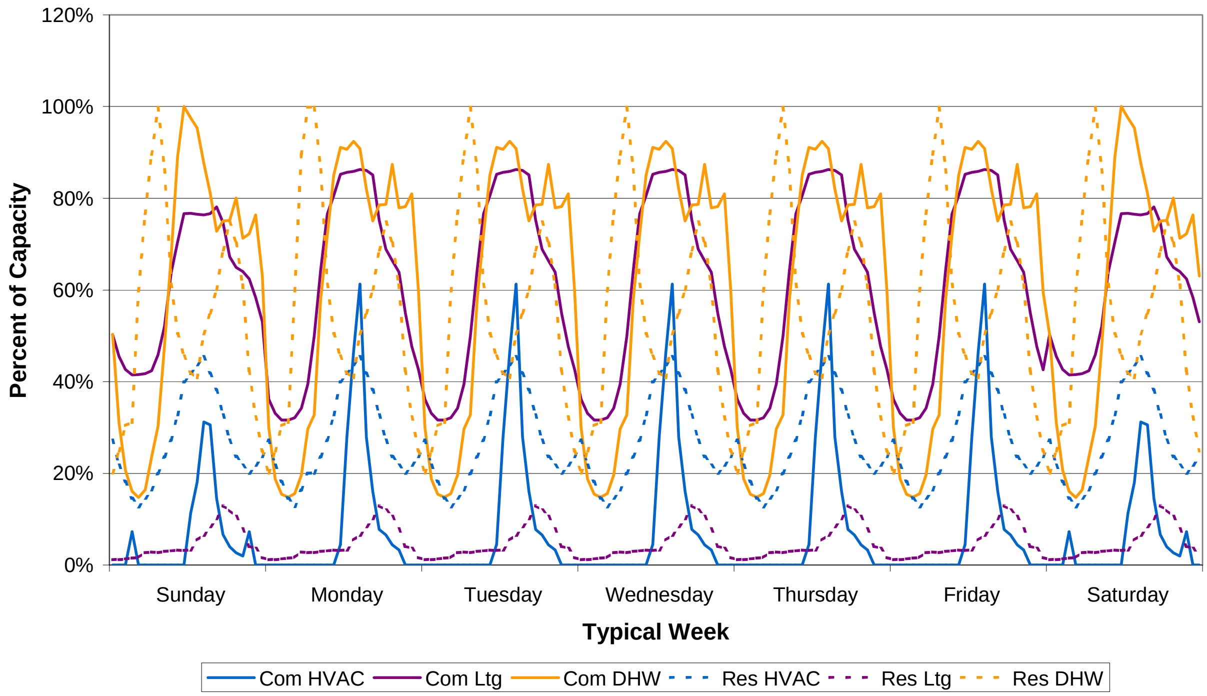

Chart Q.5
May Load Shapes

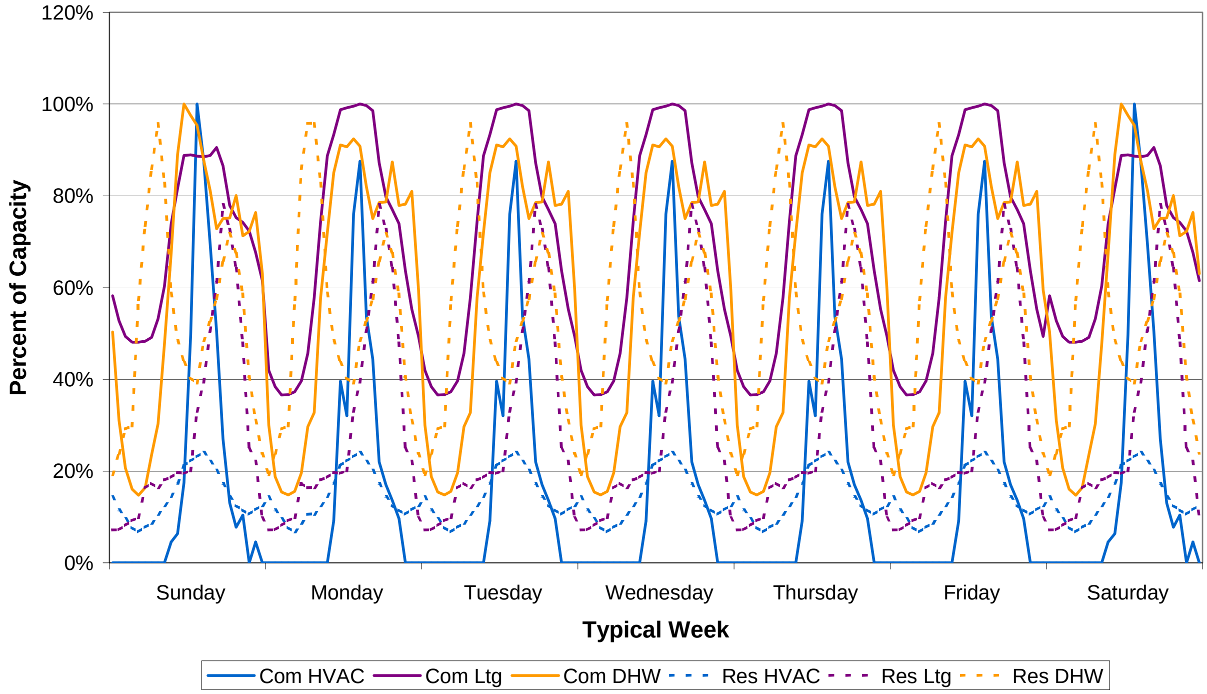

Chart Q.6
June Load Shapes

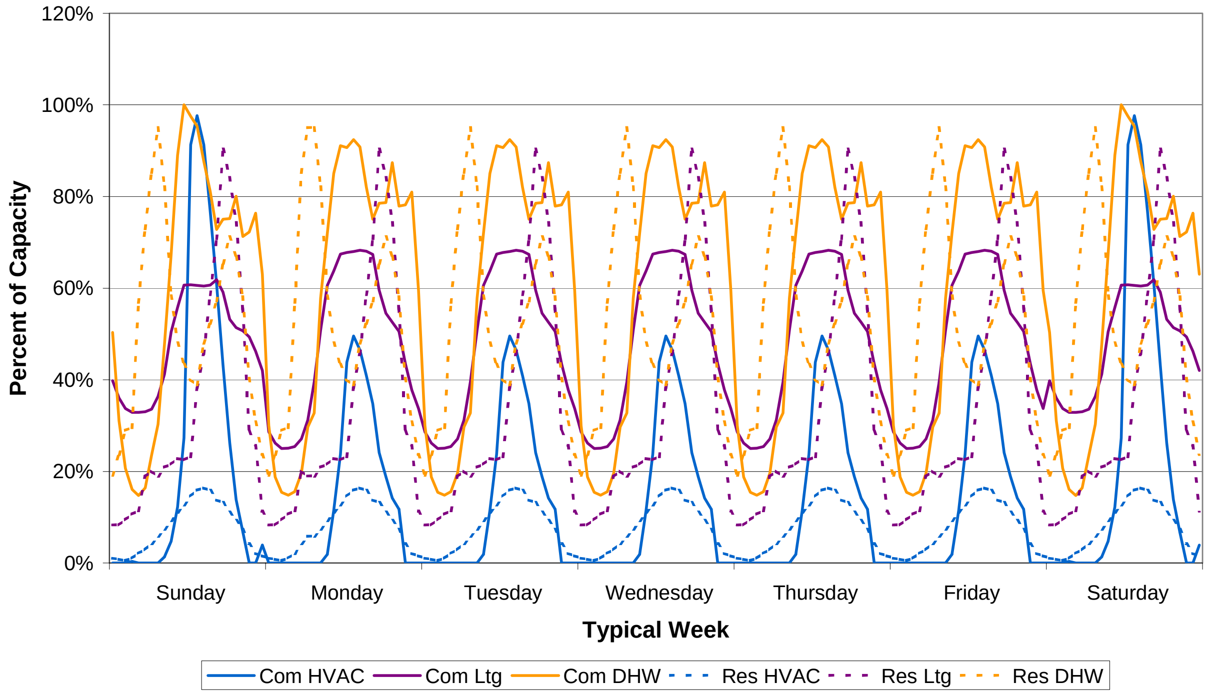

Chart Q.7
July Load Shapes

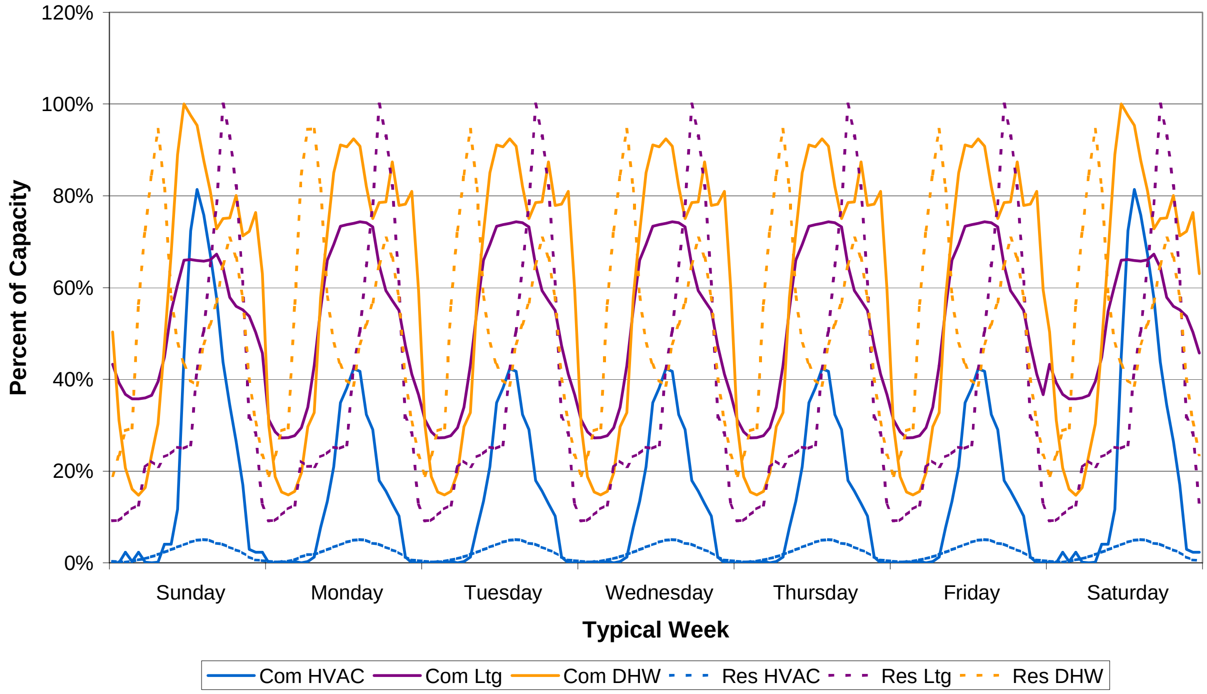

Chart Q.8
August Load Shapes

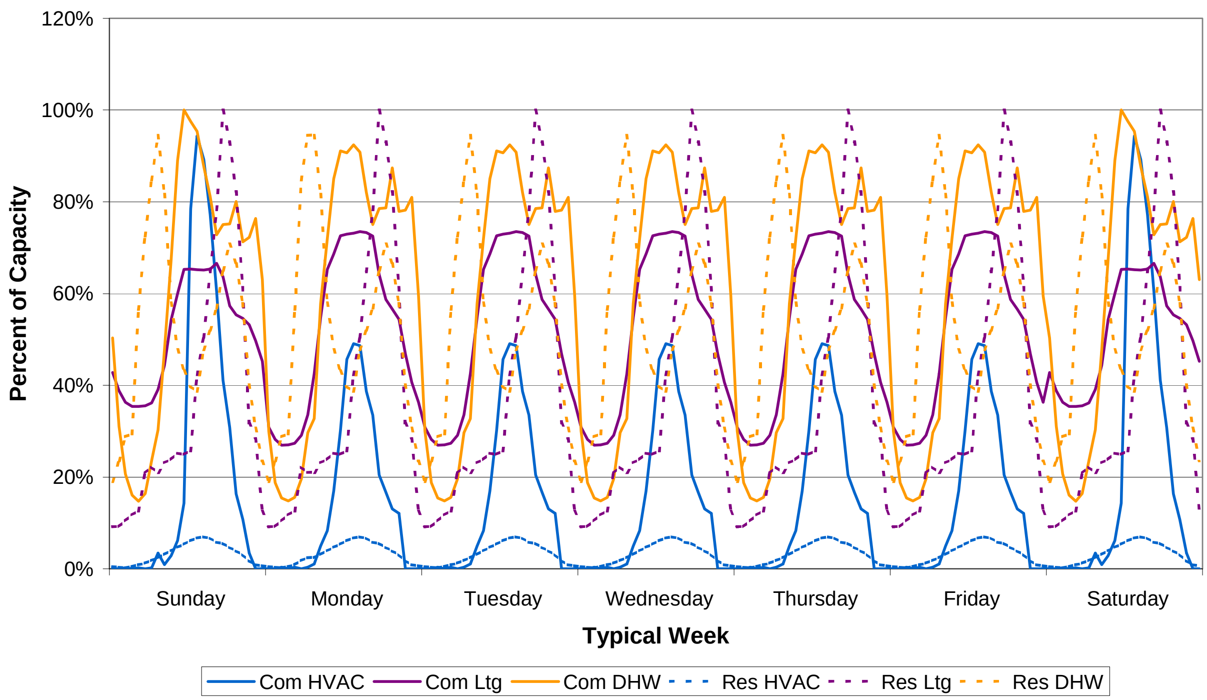

Chart Q.9
September Load Shapes

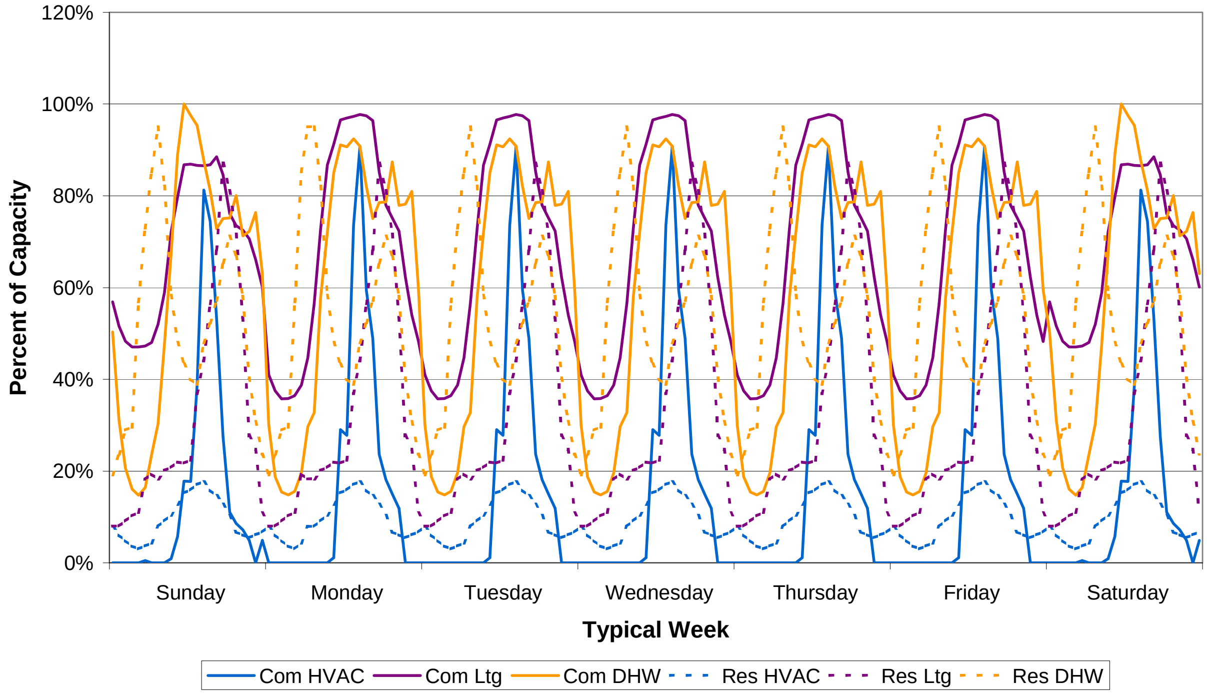

Chart Q.10
October Load Shapes

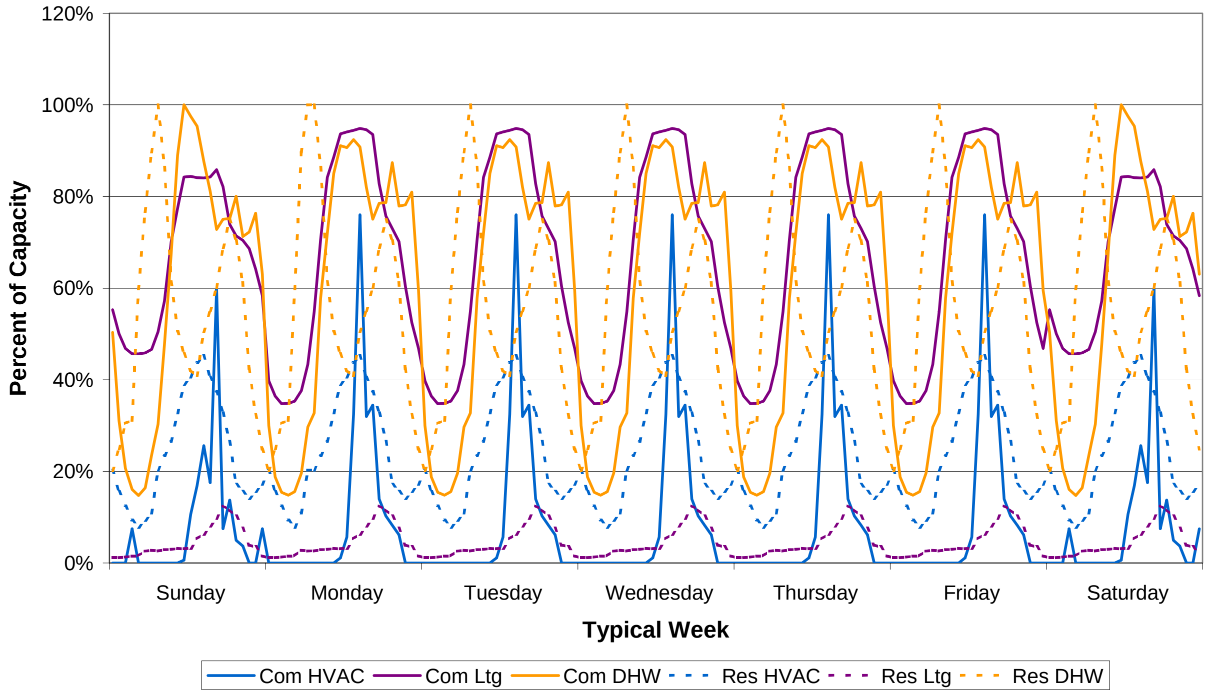

Chart Q.11
November Load Shapes

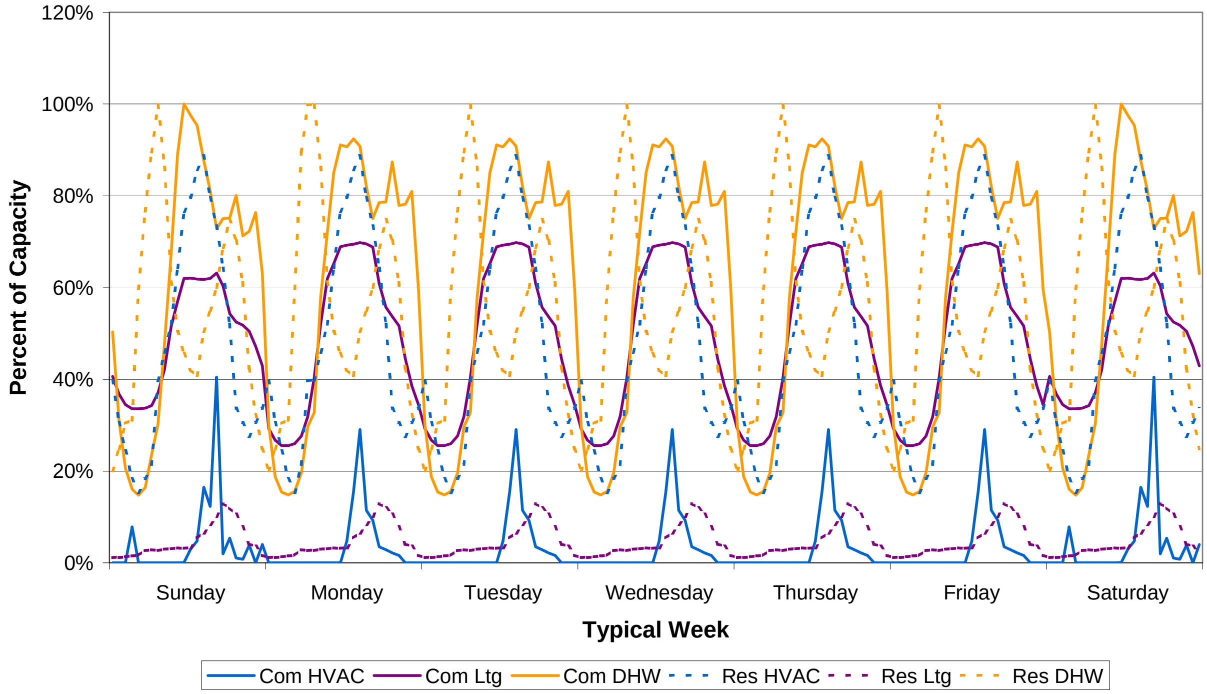

Chart Q.12
December Load Shapes

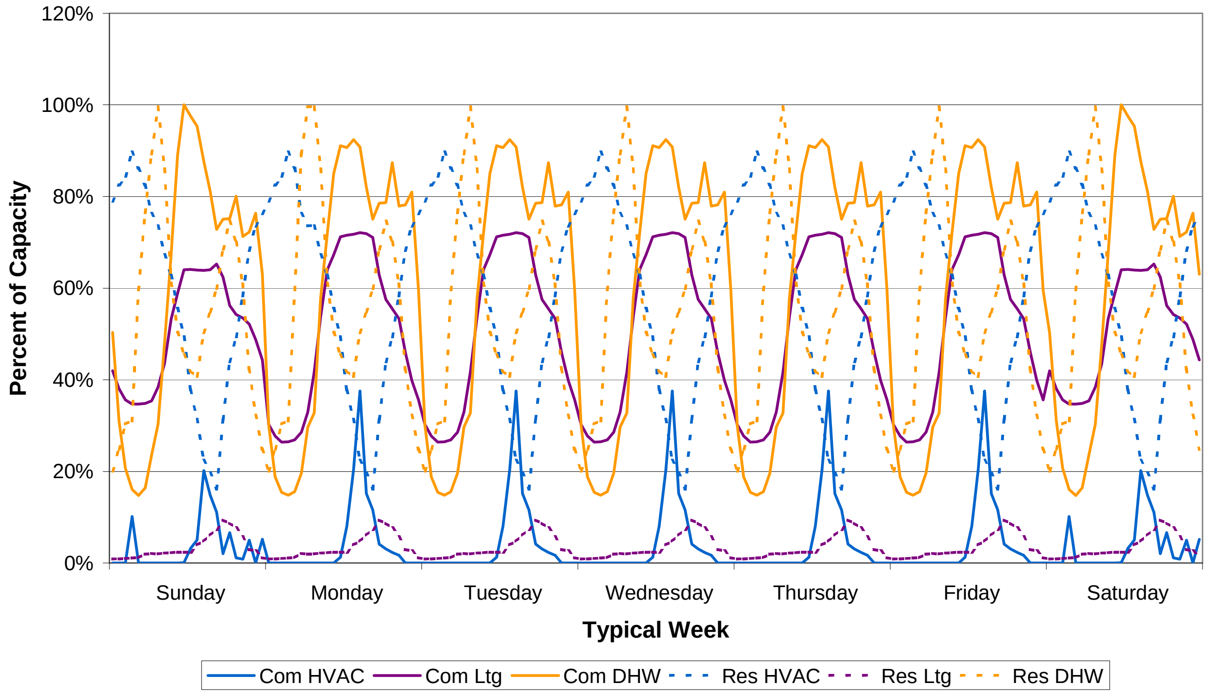

Table Q.2
DSM Resource Net Market Value
2004-2023 (in thousands of dollars)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	NPV
Com HVAC 1	-47.8	-42.6	-41.6	-33.6	-20.8	17.4	52.4	89.9	123.4	182.3	244.2	236.7	234.6	252.1	271.9	270.7	290.3	280.0	252.3	294.7	861.8
Com HVAC 2	-12.2	-11.8	-11.9	-11.2	-10.2	-6.5	-3.2	0.4	3.5	9.2	15.1	14.1	13.6	15.1	16.8	16.4	17.9	16.6	13.5	17.4	1.2
Com HVAC 3	-2.1	-2.1	-2.2	-2.1	-2.0	-1.7	-1.4	-1.0	-0.7	-0.2	0.4	0.2	0.1	0.3	0.4	0.3	0.4	0.2	-0.1	0.2	-10.5
Com HVAC 4	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.2	-0.2	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.2	-0.2	-0.2	-2.4
Com Ltg 1	209.5	222.1	227.8	246.9	272.3	296.8	319.8	338.9	347.0	374.4	411.1	409.8	420.3	439.4	454.1	454.1	476.3	480.5	469.8	507.4	3159.3
Com Ltg 2	16.8	18.0	18.5	20.3	22.8	25.1	27.3	29.1	29.8	32.4	36.0	35.7	36.6	38.3	39.6	39.5	41.5	41.7	40.5	44.0	268.8
Com Ltg 3	1.2	1.3	1.3	1.5	1.7	1.9	2.1	2.3	2.4	2.6	3.0	2.9	3.0	3.1	3.2	3.2	3.4	3.4	3.2	3.6	21.0
Com Ltg 4	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	1.4
Com DHW 1	4.3	4.5	4.6	5.0	5.5	6.0	6.5	6.9	7.0	7.6	8.3	8.3	8.6	9.0	9.2	9.2	9.6	9.8	9.6	10.3	64.0
Com DHW 2	0.3	0.4	0.4	0.4	0.5	0.5	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.9	0.8	0.9	5.5
Com DHW 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.4
Com DHW 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Res HVAC 1	19.3	20.5	20.6	22.8	25.6	27.0	28.1	27.8	25.7	25.1	24.3	25.0	26.2	27.1	27.6	27.1	28.1	27.9	28.4	30.8	238.2
Res HVAC 2	1.3	1.4	1.4	1.6	1.9	2.0	2.1	2.0	1.8	1.7	1.6	1.7	1.8	1.8	1.9	1.8	1.9	1.8	1.8	2.0	16.5
Res HVAC 3	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.7
Res HVAC 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Res Ltg 1	102.8	112.7	117.6	131.4	148.2	183.1	221.8	270.8	308.9	373.3	457.0	447.0	459.7	483.5	495.9	494.6	527.1	543.8	511.6	555.7	2664.5
Res Ltg 2	6.1	7.0	7.4	8.7	10.3	13.7	17.4	22.2	25.9	32.2	40.5	39.3	40.4	42.6	43.7	43.4	46.5	47.9	44.5	48.7	218.4
Res Ltg 3	0.1	0.2	0.2	0.3	0.5	0.8	1.1	1.6	2.0	2.6	3.4	3.3	3.3	3.5	3.6	3.6	3.9	4.0	3.6	4.0	15.8
Res Ltg 4	-0.1	-0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.3	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.8
Res DHW 1	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.4	0.5	0.6	0.6	0.6	0.7	0.7	0.6	0.7	0.7	0.6	0.7	3.3
Res DHW 2	-0.1	-0.1	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.3
Res DHW 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1
Res DHW 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Chart Q.13
Hourly Electric Market Prices vs. Commercial HVAC
2004

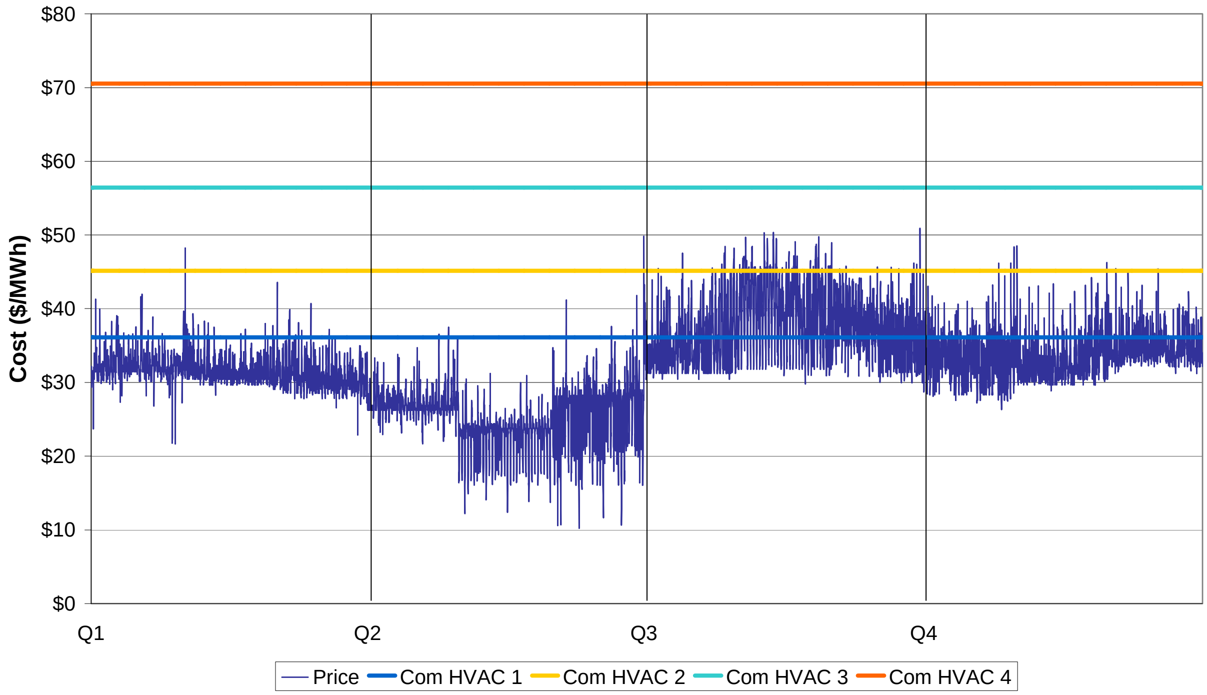

Chart Q.14
Hourly Electric Market Prices vs. Residential HVAC
2004

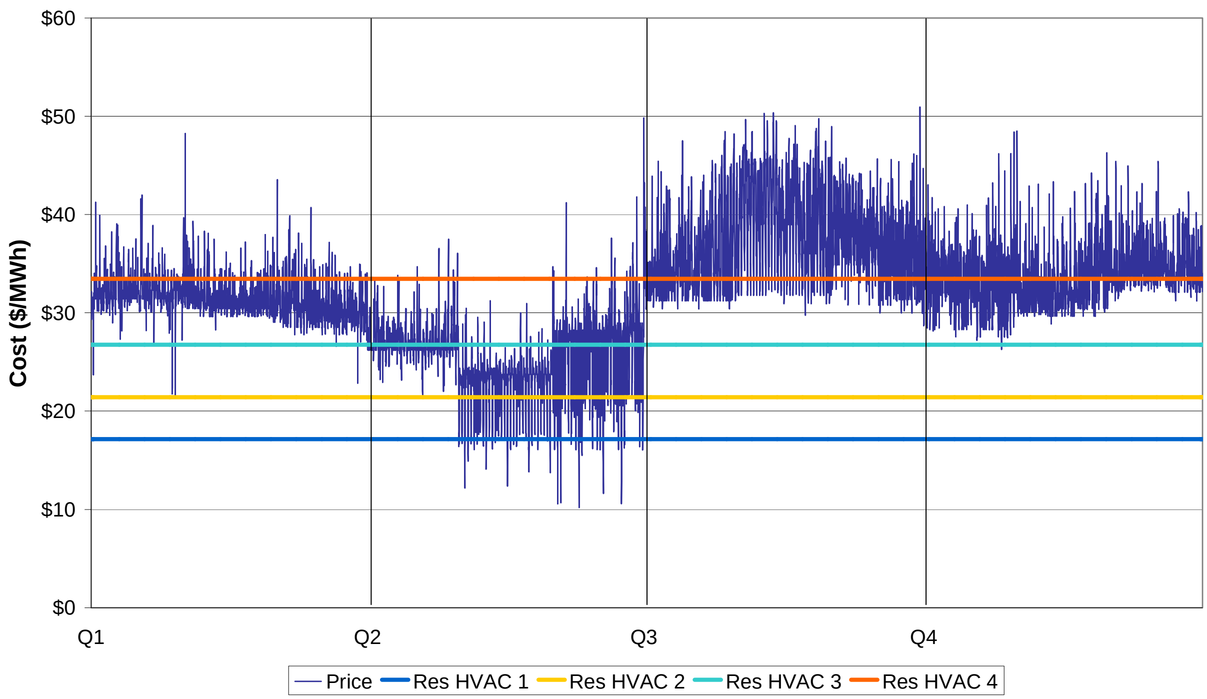

Chart Q.15
Hourly Electric Market Prices vs. Commercial Lighting
2004

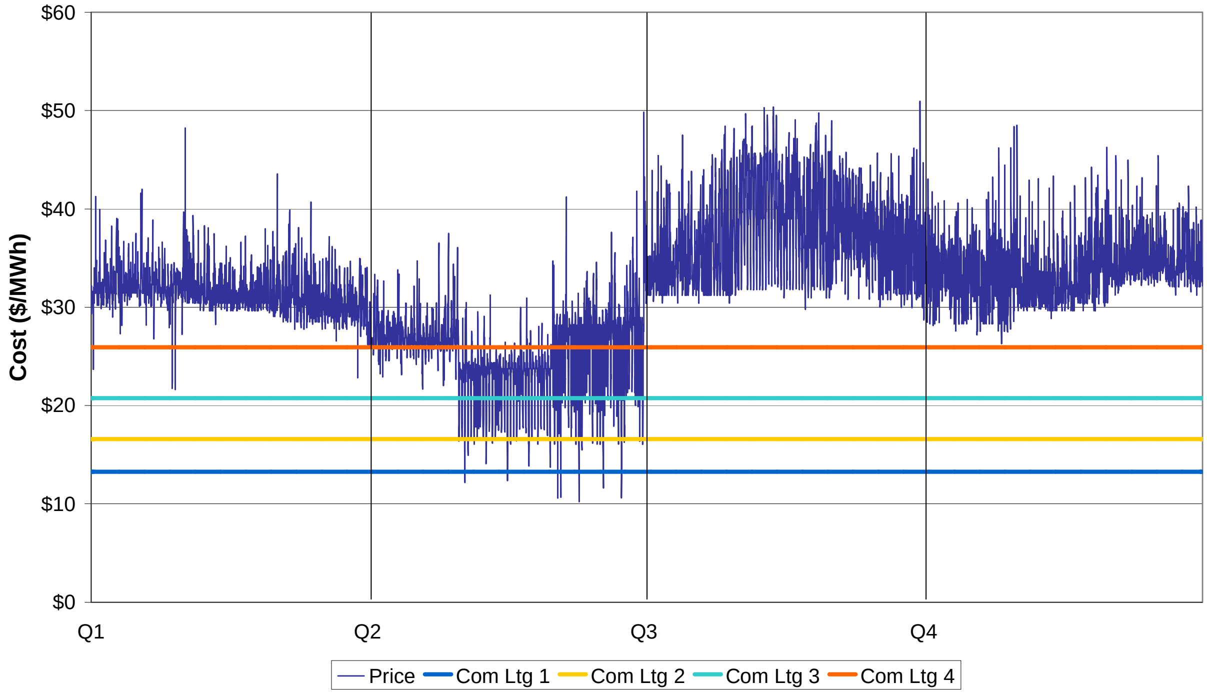

Chart Q.16
Hourly Electric Market Prices vs. Residential Lighting
2004

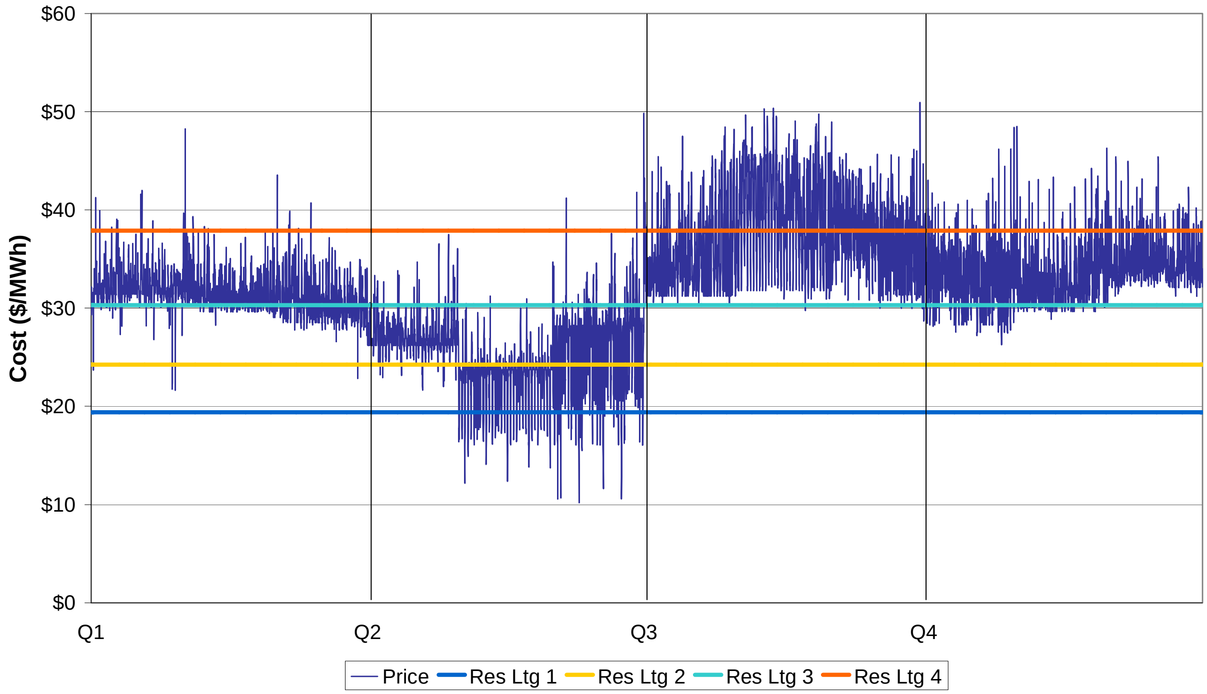

Chart Q.17
Hourly Electric Market Prices vs. Commercial DHW
2004

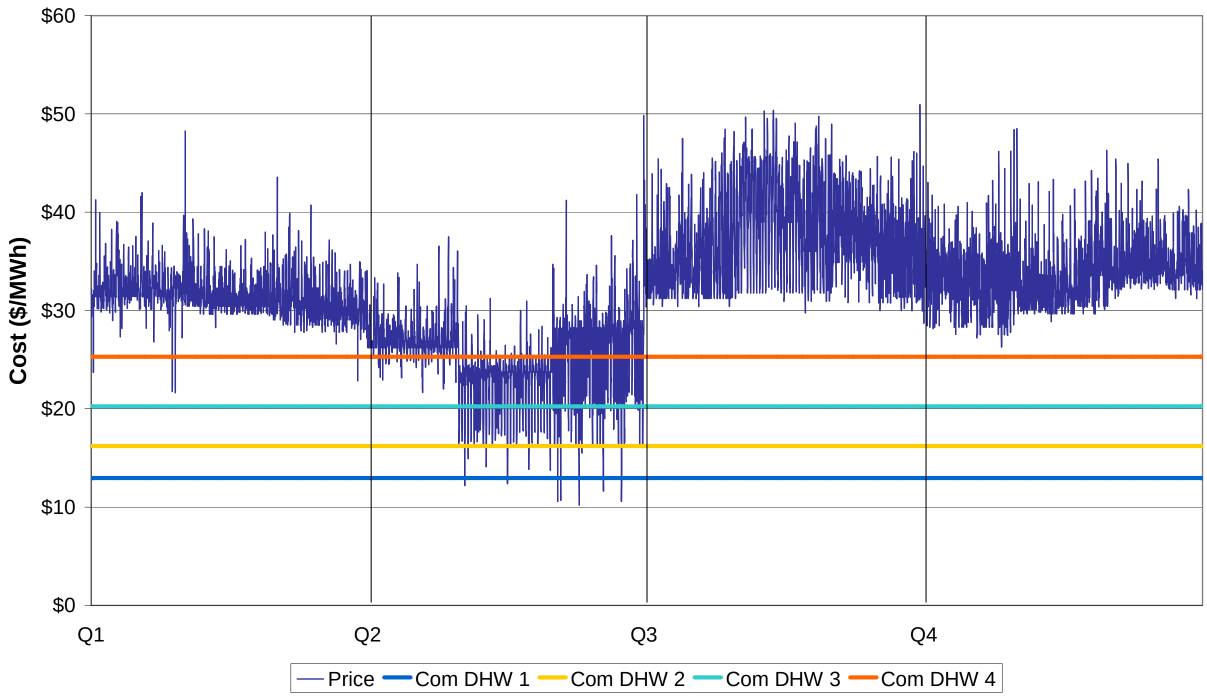

Chart Q.18
Hourly Electric Market Prices vs. Residential DHW
2004