Analysis of the Bonneville Power Administration's Potential Future Costs and Revenues

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Contents

Executive Summary

This report describes an analysis of the Bonneville Power Administration's potential financial situation under a range of future electricity market conditions and possible fish and wildlife mitigation scenarios. The objective of this report is to assist decision-makers in making better-informed decisions regarding the long-term value of the Bonneville system and its nearer term ability to recover its costs. The work was carried out by the staff of the Northwest Power Planning Council with the participation and oversight of representatives of the key interest groups concerned with Bonneville's financial condition.

The metric used in evaluating Bonneville's situation is potential net revenue - the difference between the value of Bonneville's electricity production evaluated at market prices and Bonneville's costs. Using market value is not a recommendation that Bonneville sell at market prices. It does, however, provide a measure of the competitiveness of Bonneville generation. What this metric shows is the value to customers of buying all of Bonneville's product at cost relative to the alternative of purchasing the same product at market prices.

Market price projections were developed using a simulation model of the West Coast electricity system. The model assumes a competitive generation market where prices are set by the marginal operating cost of the most expensive generation that has to operate to meet load at any given time. Alternative sets of assumptions were made regarding key driving factors such as load growth, natural gas prices, and generation technology development. The intent was to develop a range of forecasts that, in the opinion of staff and the oversight groups, spanned the plausible range of possible future market prices. The forecasts of average annual market prices are shown in Figure ES-1. These are shown in nominal terms (2.5 percent inflation) and represent the price for an undelivered product.

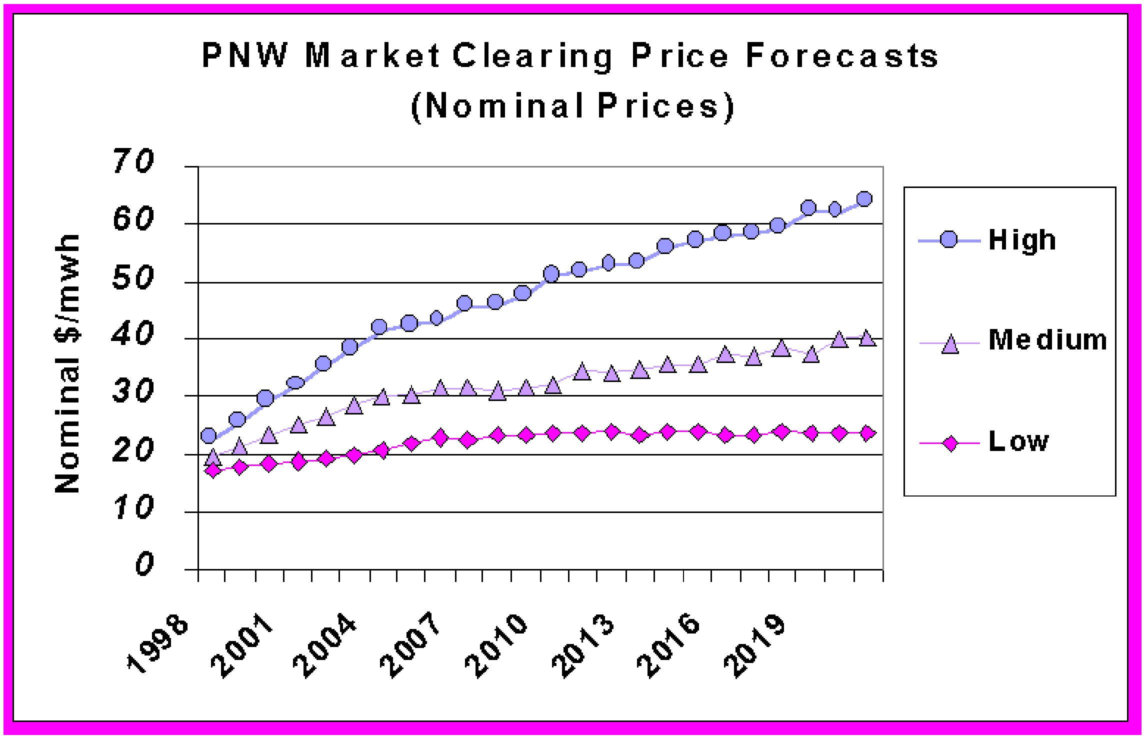


Figure ES-1

A range of possible future fish and wildlife mitigation scenarios was identified using alternatives developed by the National Marines Fisheries Service, the Columbia Basin Fish and Wildlife Authority (CBFWA), the Columbia River Inter-Tribal Fish Commission (CRITFC) and others. Included were:

- The current Biological Opinion (BiOp);
- A scenario with reduced flow augmentation;
- Two scenarios with an increased emphasis on transportation and reduced spill, with and without Clean Water Act measures;
- A scenario involving drawdown of the four lower Snake River dams;
- Two scenarios involving drawdown of the four lower Snake dams and John Day, with and without Clean Water Act measures; and ? A scenario combining five dam drawdown, increased flow augmentation and Clean Water Act measures.

The choice of the individual scenarios for this analysis has no significance other than to establish a family of scenarios that span the range of direct cost and operational impacts associated with the various scenarios under consideration by different parties. Inclusion of any scenario in this analysis does not imply endorsement by the Council, the oversight group or any of its individual members. This study did not address the biological merits of any of these scenarios. There are likely to be different biological outcomes associated with the different scenarios. The issue of biological effectiveness is currently being considered in other processes in the region, such as National Marine Fisheries Service's PATH process (Plan for the Analysis and Testing of Hypotheses).

For each of the scenarios, estimates of their non-operational costs over time (direct program, capital and operations and maintenance (O&M) costs) were obtained, relying on the work done by a number of federal and state agencies and the tribes. The cost levels and timing of implementation were accepted as presented by those agencies. The totals for non-operational costs are shown on Figures ES-2.

Council staff used the System Analysis Model to estimate the operational impacts (i.e., effect on generation). One indicator of the operational effects - the change in average annual energy production relative to the current BiOp - is shown on ES-3.

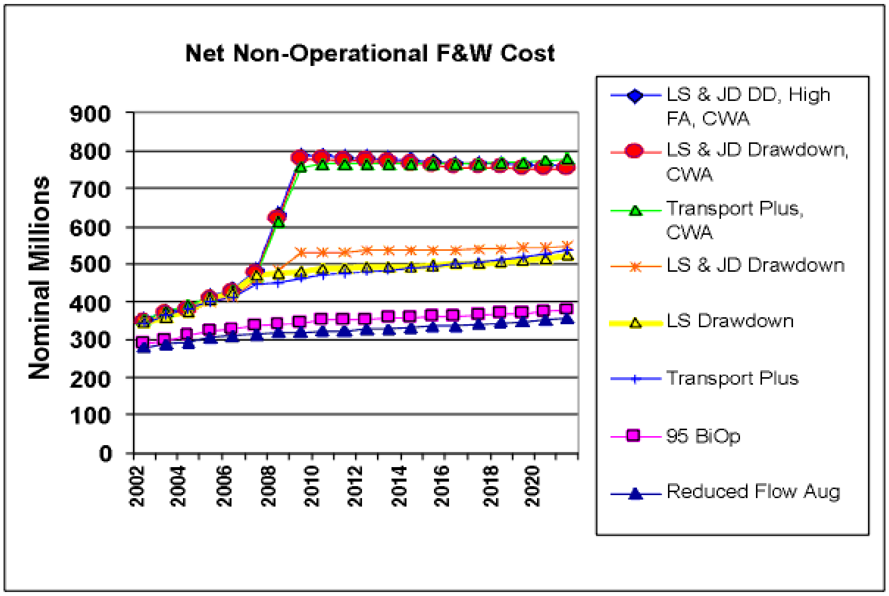


Figure ES-2

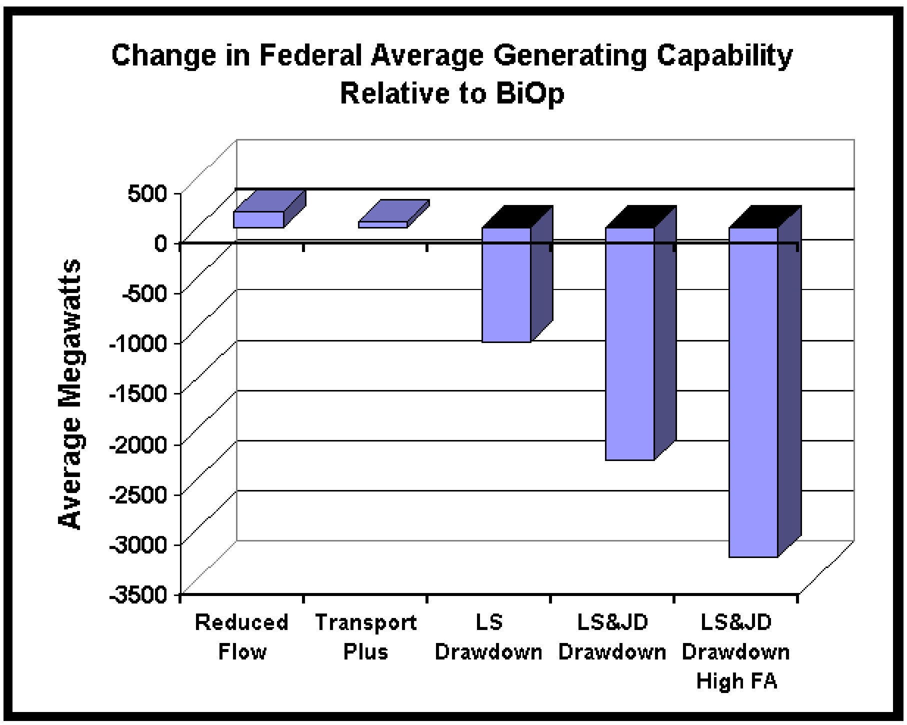


Figure ES-3

The effects of the market price projections were combined with the non-operational costs and operational effects of the fish and wildlife mitigation scenarios in an integrating simulation. The modeling objective is to estimate the potential net revenue for Bonneville under a user-specified salmon mitigation strategy and market price scenario. For analytical purposes, it is assumed that Bonneville is responsible for the full power system share of the costs in each of the fish and wildlife mitigation scenarios. That assumption should not, however, be construed as a recommendation of the oversight group or the Council.

The integrating model uses standard simulation techniques to perform the market revenue and hydro uncertainty calculations, taking into account seasonal and diurnal variations in market prices. Because reserves are a common means of mitigating financial risks, the model also simulates the use of reserves, when available, to offset possible net losses. The analysis considers only financial impacts on the federal system. Broader societal impacts like effects on irrigation or transportation are not addressed here. By the same token, the possible benefits of increased salmon returns are also not incorporated.

Results

Typical results are shown on Figure ES-4. This figure shows the potential net revenue over time (market value minus costs) for a particular fish and wildlife mitigation scenario and market price forecast. Shown are the mean value over 50 different water years as well the minimum and maximum net revenue corresponding to the worst and best water conditions. A negative value at any time indicates the amount by which Bonneville's costs exceed the market value of its production. Conversely, positive values indicate the benefit received by Bonneville customers paying cost-based rates relative to purchasing from the market. Reserves are not brought into play in this figure.

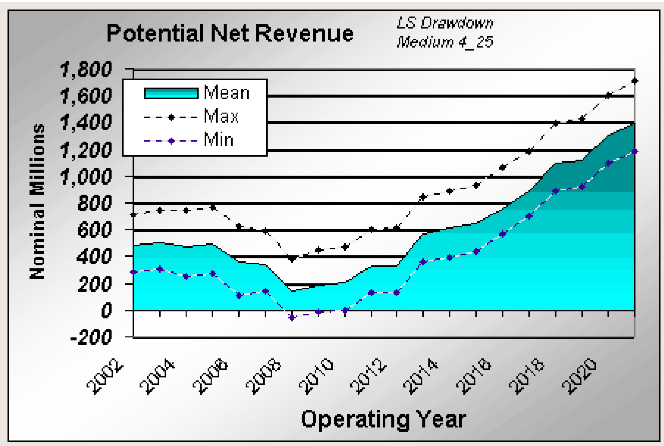
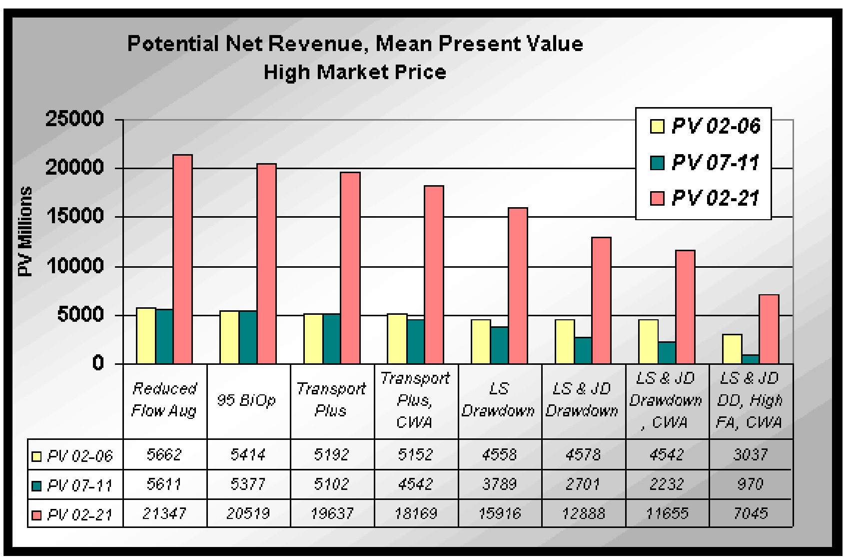


Figure ES-4

It should be noted that the minimums and maximums shown on this figure represent the net revenues under the worst and best historical hydro conditions respectively. They are the worst and best conditions that might occur in any given year. They should not be interpreted as possible multi-year series.

Summary results of the simulations for each of the fish and wildlife mitigation scenarios are shown on Figures ES-5 through ES-7 for the High, Medium and Low market price forecasts. Three sets of bars are shown for each fish and wildlife scenario. The first bar is the present value of the net revenue for the five-year period from 2002-2006. The second bar covers the period 2007-2011, while the third bar covers the entire twenty-year study period 2002-2021. The values for the bars are shown in the table at the bottom.

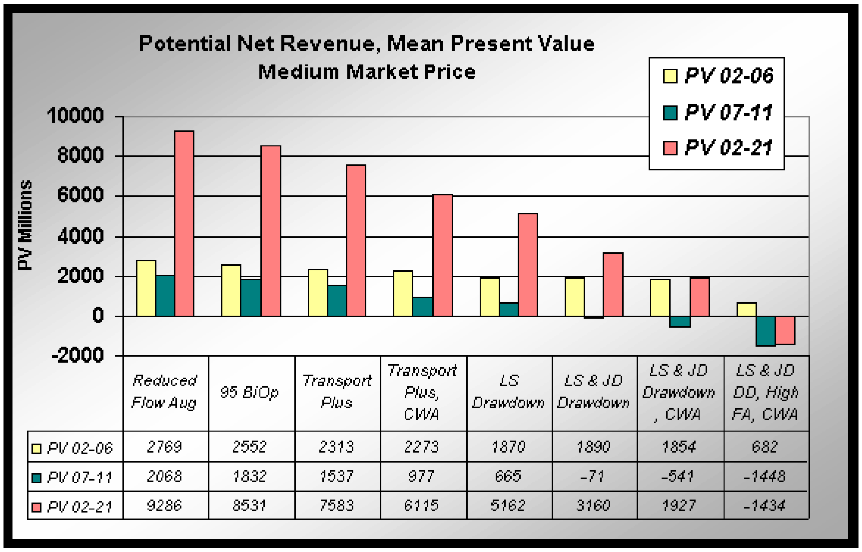


	Reduced Flow Aug	95 BiOp	Transport Plus	Transport Plus, CWA	LS Drawdown	LS & JD Drawdown	LS & JD Drawdown, CWA	LS & JD DD, High FA, CWA
PV 02-06	5662	5414	5192	5152	4558	4578	4542	3037
PV 07-11	5611	5377	5102	4542	3789	2701	2232	970
PV 02-21	21347	20519	19637	18169	15916	12888	11655	7045

Figure ES-5

High Market

The analysis shows that with high market prices, Bonneville demonstrates significant benefit to customers under all the fish and wildlife mitigation scenarios considered. However, the fact that Bonneville "can afford" the most costly fish and wildlife scenarios doesn't mean those scenarios are without cost. For example, if the power system is required to cover all the costs of moving from the current biological opinion (BiOp) to five dam draw down with Clean Water Act measures, electricity consumers would be investing an additional $9 billion over 20 years in salmon mitigation efforts. This investment would increase long-term electricity costs to consumers by that amount.



	Reduced Flow Aug	95 BiOp	Transport Plus	Transport Plus, CWA	LS Drawdown	LS & JD Drawdown	LS & JD Drawdown , CWA	LS & JD DD, High FA, CWA
PV 02-06	2769	2552	2313	2273	1870	1890	1854	682
PV 07-11	2068	1832	1537	977	665	-71	-541	-1448
PV 02-21	9286	8531	7583	6115	5162	3160	1927	-1434

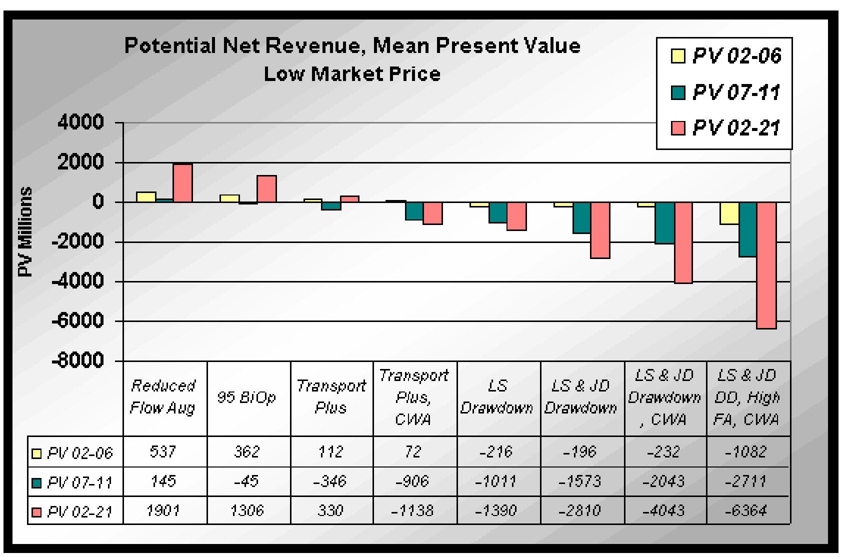
Figure ES-6

Medium Market

With medium market prices (considerably greater than current prices but much less than the high forecast), Bonneville demonstrates benefits to customers for the study period in all but the most costly of the fish and wildlife scenarios evaluated. It also demonstrates positive value in each of the sub-periods for all but the scenarios involving five dam drawdowns. In these instances, negative net revenues are experienced in the 2007 -2011 period. Again, although Bonneville would be able to afford most of the fish and wildlife mitigation scenarios, it would require additional billions in investment that would be paid for by higher electricity costs to consumers.

Low Market

In contrast, low market conditions (on average over the 20 year period, only slightly greater than current prices in nominal terms, declining in inflation-adjusted terms) present Bonneville with significant financial challenges. With low market prices, Bonneville experiences periods of negative net revenues under any fish and wildlife scenario involving additional costs or degradation of power production capability. The most critical period is typically the 2007-2011 period when the higher fish and wildlife costs and/or generation losses occur and before Bonneville's debt service on the Washington Public Power Supply System bonds begins to decline.



	Reduced Flow Aug	95 BiOp	Transport Plus	Transport Plus, CWA	LS Drawdown	LS & JD Drawdown	LS & JD Drawdown , CWA	LS & JD DD, High FA, CWA
PV 02-06	537	362	112	72	-216	-196	-232	-1082
PV 07-11	145	-45	-346	-906	-1011	-1573	-2043	-2711
PV 02-21	1901	1306	330	-1138	-1390	-2810	-4043	-6364

Figure ES-7

Reserves

If Bonneville is able to enter the study period with substantial reserves ($500 million was assumed in this study), periods of negative net revenues can be mitigated in the more moderate cost fish and wildlife scenarios. This is illustrated in Figure ES-8. In this case, reserves can handle the losses for several years but are eventually exhausted by sustained losses and cannot be rebuilt for several years. To get through this period, Bonneville would need further cost cuts or additional revenue sources. Some would also argue that the presence of high reserve levels reduces Bonneville's incentive to control costs and is an attractive target for those who would have Bonneville financially support other activities.

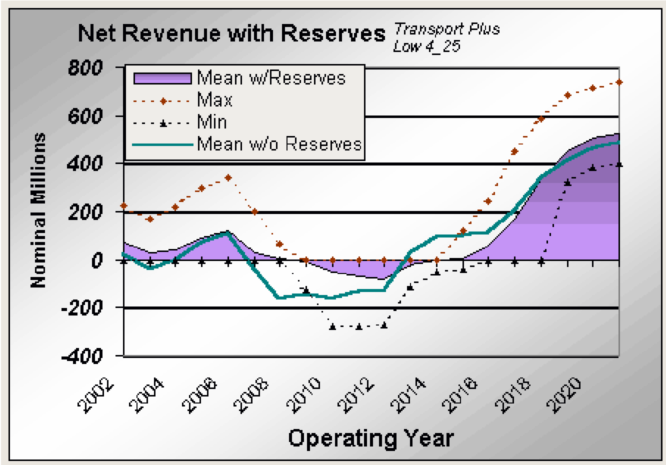


Figure ES-8

With low market conditions, Bonneville's financial situation is very much "on the cusp." Relatively small changes make significant differences in the outcomes. For example, successful implementation of the further reductions in Bonneville's base costs recommended by the Cost Review could, in the example above, largely eliminate the negative cash flows. Also, in several instances, market prices only 10 percent higher than the low price forecast mean the difference between negative and positive net revenues.

Conclusions

Under a wide range of conditions, Bonneville demonstrates significant value to customers even if called upon to bear relatively large additional fish and wildlife mitigation costs. Only under combinations of persistent low market conditions and increased fish and wildlife costs and/or operational impacts does Bonneville experience significant negative net revenues for extended periods. Those results are extremely sensitive to small changes in Bonneville's costs or market prices. This underscores the importance of Bonneville's cost management efforts.

Financial risk management mechanisms like reserves can mitigate the negative net revenues in some conditions. In other conditions, however, the mitigating effect of the assumed reserves and/or further cost reductions is insufficient. In these cases, Bonneville would need larger reserves; some sort of contingent cost recovery mechanism or may have to look to other of funding. It is also possible that the schedules for implementation of the various fish and wildlife mitigation scenarios used in this analysis will not be met. The biological and economic effects of changes in the schedule for implementation of fish and wildlife measures should be evaluated.

Introduction

The Northwest is fast approaching a number of critical decisions affecting the Bonneville Power Administration, the region's hydroelectric system and the environment. They include:

- Decisions on the part of regional utilities and others as to whether and to what degree to contract for purchases from Bonneville for the FY 2002 - 2006 period and beyond;
- Decisions by the National Marine Fisheries Service (NMFS), the Environmental Protection Agency and others regarding what fish and wildlife mitigation measures to call for; and
- Decisions by Congress and the Administration about the need for and structure of any kind of contingent cost recovery mechanism.

These decisions are highly interrelated and hinge, at least in part, on decision makers' perceptions of Bonneville's near and long-term financial condition. Bonneville's financial condition, in turn, depends on the future market prices of electricity, Bonneville's costs both for regular operations and for possible other costs and additional fish and wildlife mitigation requirements, and the productive capacity of the federal power system as fish and wildlife mitigation and other factors may affect it.

Objective of this Report

The objective of this report is to assist decision-makers in making better-informed decisions regarding the long-term value of the Bonneville system and its nearer term ability to recover its costs. While we cannot specify the important future factors with certainty, we can help decision-makers explore the possible consequences of different choices and circumstances. Decision-makers will make their own assessments of the likelihood of those choices and circumstances.

Approach

The analysis was developed with the active participation and oversight of a technical work group and a policy oversight group. Each group was made up of respected representatives of key interest groups. The purpose of these groups was to allow access to their expertise and perspectives and to ensure that there was broad understanding of the methods and assumptions driving the results. The members of the technical work group and policy oversight group are shown in Appendix A.

The analytical approach is diagrammed in Figure 1. A family of market price projections was developed using a model of the West Coast electricity system. The intent was to develop a range of forecasts that, in the opinion of staff and the oversight groups, spanned the plausible range of possible future market prices. Because levels of hydro production are observed to affect market prices, the effects were analyzed in the model so that the effects of hydro variation could be taken into account.

A number of possible future fish and wildlife mitigation scenarios were chosen from alternatives developed by the National Marines Fisheries Service, the Columbia Basin Fish and Wildlife Authority (CBFWA), the Columbia River Inter-Tribal Fish Commission (CRITFC) and others. The choice of the individual scenarios for this analysis has no significance other than to establish a family of scenarios that span the range of direct cost and operational impacts of the scenarios under consideration by various parties. Inclusion of any scenario in this analysis does not imply endorsement by the Council, the oversight group or any of its individual members.

For each of the mitigation scenarios, estimates of their direct program, capital and operations and maintenance (O&M) costs over time were obtained, relying on the work done by a number of federal and state agencies and tribes. No judgments or adjustments were applied to these costs. The power system's share of these costs was estimated using established allocation percentages (e.g., X percent to power, Y percent to irrigation, Z percent to navigation) at each of the projects. In addition, the timing of the implementation of measures, i.e., the years in which costs and operational effects occur, were accepted from the agencies. No adjustments were made. The operational impacts of the scenarios, i.e., changes in quantities and shape of hydro generation as a result of changes in flow requirements, spill or system reconfiguration, were estimated by Council staff using the System Analysis Model (SAM).

Estimates of Bonneville's other future power business line costs (debt repayment and expenses of operation not including fish and wildlife costs) were obtained from Bonneville. Two sets of estimates were used. One represented implementation of Bonneville's planned budget reductions as a result of internal planning carried out during the summer and fall of 1997. The second represented implementation of the additional budget reductions recommended by the Cost Review that concluded this March.

These three sets of information were brought together in an integrating analysis using a spread sheet model. The model allows specification of the fish and wildlife mitigation scenario and market price projection. It simulates potential net revenue - the value of Bonneville's production at market prices less its costs. This is not a recommendation for market pricing. Net revenue, however, is a metric that indicates the value of the federal system. The model takes into account the effect of hydro production on market prices. The simulation allows the user to specify hydro conditions or to make multiple runs with random or sequential draws from the historical hydro record. The model also allows evaluation of the effect of reserves in mitigating cash flow problems and the ability to test the sensitivity of results to variations in market prices or costs. The output includes the net revenue (value of production at market prices minus cost) over the period 2002 - 2021 as well as present value of the net revenues for the periods 2002-2006, 2007-2011, 2012-2021 and for the entire 20-year study period. Examples of typical output are shown in Figures 2 and 3.

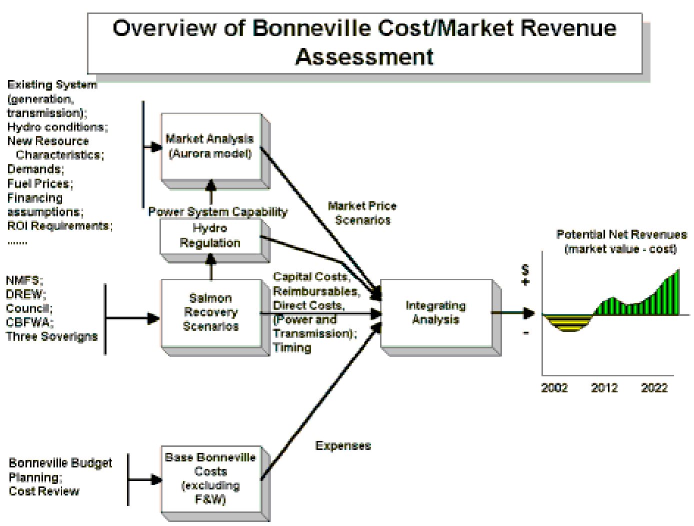


Figure 1

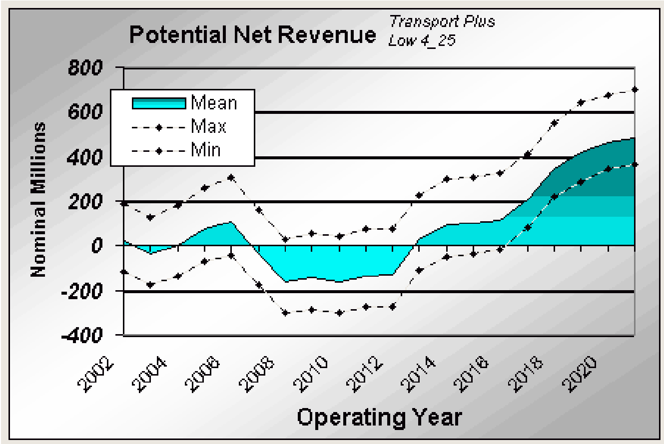


Figure 2

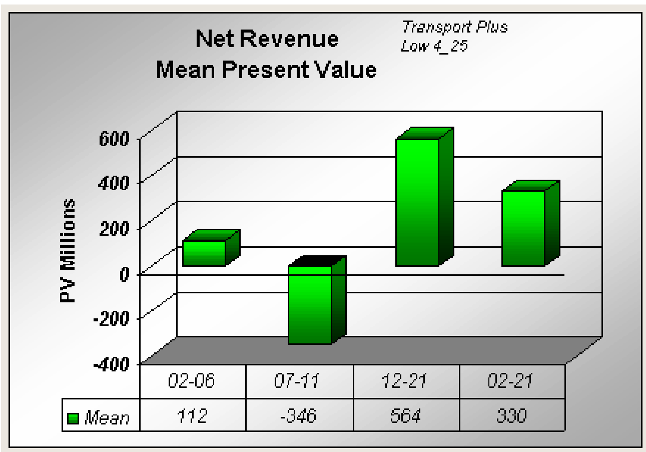


Figure 3

Interpreting the results

This analysis is intended to give decision-makers insights into the potential long-term value of the Bonneville system and its shorter-term ability to cover its costs. However, the analysis does not model Bonneville's actual rates or make assumptions about any contingent cost recovery or, more commonly, "stranded cost" mechanisms. The primary perspective that these results represent is that of a customer.

The choice facing potential Bonneville customers is that of paying Bonneville's cost-based rates or buying at market prices. If Bonneville's rates and its costs per unit of output were identical, then the results of this analysis would provide a relatively accurate portrayal of the long-term value to the customer of purchasing from Bonneville relative to relying on the market. It would also give a reasonable representation of the relative benefit or cost of purchasing at Bonneville's cost instead of the market price at any point in time.

However, Bonneville's rates are effectively constrained to be the lower of cost or market. Bonneville may be able to charge rates that prove to be somewhat above market for part of a rate period. But at the end of that rate period, customers would be free to choose to continue to purchase from Bonneville or to purchase from the market. Bonneville could not set rates much above expected market prices without losing customers. Therefore, absent any contingent cost recovery mechanism, the customers would not face the losses relative to purchasing from the market indicated by the area below the axis in Figure 2.

From a longer-term perspective, Bonneville losses might be treated as Treasury deferrals to be recovered with interest from customers in a future period when conditions permit. If that were the case, the 20-year present value to customers would be the same as the present value indicated by the 20-year present value on Figure 3.

Market Analysis

Modeling Framework for Market Prices

In developing the market price forecasts, the Council relied principally on a proprietary model developed by Electricity Pricing Information Services, Inc (EPIS) called Aurora. Aurora is designed specifically to model wholesale electricity prices in a deregulated generation market.

In a deregulated generation market, economic theory says that prices at any given time should be based on the marginal cost of production. In a competitive electricity market, prices will rise to the point of the variable cost of the last generating unit needed to meet demand. This is the economic model currently in use in the California Power Exchange. One of the principle functions of Aurora is to estimate this hourly market-clearing price at various locations within the Western Systems Coordinating Council (WSCC) area. Aurora uses a fundamentals approach in estimating prices, reflecting the economics and physical characteristics of demand and supply.

Aurora estimates prices by using hourly demands and individual resource operating characteristics in a transmission-constrained chronological dispatch algorithm. The operation of resources within the WSCC is modeled to determine which resources are on the margin for each area in any given hour.

In Aurora, the WSCC is broken into 12 geographic areas largely defined by states, with the exception of California, which is split into a northern and southern area, and Oregon and Washington, which are combined into one area. Long term average demand and hourly demand shapes for these regions are input. These demand regions are connected by transmission links with specified transfer capabilities, losses and wheeling costs.

Existing supply-side generating units, approximately 2000 of them in the WSCC, are defined and modeled individually with specification of a number of cost components and physical characteristics and operating constraints. Hydro generation for each area, with instantaneous maximums, off peak minimums, and sustained peaking constraints are also input. Demand side resources and price induced curtailment functions are defined, allowing the model to balance use of generation against customer demand reduction alternatives.

Aurora uses this information to build a least cost dispatch for the WSCC. Units are dispatched according to variable cost, subject to non-cycling and minimum run constraints until hourly demand is met in each area. Transmission constraints, losses, wheeling costs and unit start-up costs are reflected in the dispatch. The market-clearing price is then determined by observing the cost of meeting an incremental increase in demand in each area. All operating units in an area receive the hourly market clearing price for the power they generate.

The hourly market clearing prices are developed on an area-specific basis. The analysis for this report uses the Oregon/Washington area price to value Bonneville generation. This price can be interpreted as the average busbar price as seen by generation in the OR/WA area. Charges for delivery within the OR/WA area are not included in the price.

Aurora also has the capability to simulate 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 will only be built when the combination of hourly prices and frequency of operation for a resource generate enough revenue to make construction profitable, i.e. the ability of investors to 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. This effectively results in construction and retirement decisions being based on "perfect knowledge" of future prices.

Existing units that can't 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 of the WSCC, the rate at which existing units can be retired for economic reasons is constrained in these studies until 2010.

Description of the Market Forecasts

Three electricity market forecasts have been developed to reflect uncertainties in the underlying assumptions of the analysis. These projections were created using a range of assumptions about three key inputs: electricity demand growth, fuel prices, and gas-fired combined-cycle generation efficiency and cost. For example, the low electricity market assumptions included low demand growth, low fuel prices, and optimistic assumptions about combined-cycle combustion turbines. Each of the individual low assumptions were intended to be plausible outcomes but not very likely. When all three are combined in one forecast, the result is still plausible but even less likely.

The high forecast uses assumptions at the high end of the range. The medium forecast uses a mid-range assumption for each of the key determinants. The table below summarizes the key assumptions for each forecast. The assumptions are discussed in more detail in the following sections.

Assumptions

	Low	**Medium**	**High**
Electricity Demand Growth			
Growth rate %/Year	0.50%	1.50%	2.50%
Natural Gas Prices			
Starting price $/MMBtu	$1.80	$2.00	$2.25
Real Growth Rate %/Year	-1.00%	0.80%	1.50%
Nominal Growth Rate %/Year	1.48%	3.32%	4.04%
Combined Cycle Combustion Turbine Technology			

Capital Cost Relative to Current ($546/kw)	1.0	1.1	1.21
2020 Efficiency	57%	54%	53%
Real Rate of Cost Reduction Due to Technology Improvement %/Year	-1.20%	-0.60%	-0.10%
Nominal Rate of Cost Change %/Year	1.27%	1.89%	2.40%

Key Input Assumptions

Electricity Demand Growth

Aurora is driven by hourly electricity demand in its 12 regions. The hourly pattern of demand is allocated from the annual average. Its hourly composition does not change except to the extent demand-side peaking resources reduce peak demand. We used the hourly composition factors embedded in Aurora. A check of those factors against available data and some results from the Council's Load Shape Forecasting System showed the Aurora factors to be reasonable. Starting year demands were taken from WSCC data and allocated to regions (mostly states) based on historical sales data.

Demand was assumed to grow at equal rates in all of the demand areas. Although this will certainly not be the case, we did not have access to any state level demand forecasts and historical relative growth rates for state may not be a good indicator of future demand growth. For the medium case, demand is assumed to grow at 1.5 percent annually. In the low case, the assumption is 0.5 percent per year, and in the high case it is 2.5 percent.

Demand-Side Peaking Resources

In a completely deregulated generation environment, the level of new resource development will be strongly influenced by the price customers are willing to pay for electricity, and what alternatives they have for substitution. Customer-supplied substitutes for electric power service include demand management, conservation, on-site generation and curtailment. As the price customers are willing to pay to avoid interruption in service increases, overall generation reliability should increase as well, as long as those price signals are visible to resource developers. Instead of the rule based/regulatory driven generation reliability criteria of the past, competition will lead to economic based reliability criteria. An important input into Aurora is the set of price-induced responses customers are likely to make in response to changing electricity prices. Aurora uses these to evaluate the economic trade-off between construction of resources and customer curtailment.

Unfortunately there is relatively little information available for estimation for what these price response functions will look like in a deregulated market. The assumptions for this analysis are based principally on data published by the Energy Information Administration (EIA) estimating the amount and cost of utility peak and energy savings in the WSCC for 1996. The assumptions used in this analysis for the supply curve for demand side actions are shown in the following table. This is a step function defined through a percentage of area peak demand. In these studies, the same function is used in each area of the WSCC. This function implies that up to 25 percent of peak demand can be displaced through customer alternatives costing up to 500 $/Mwh. The 1000 $/Mwh beyond 25% of peak demand is the assumption for the cost of non-discretionary curtailment.

Step	% of Peak Dem	Cost - 1997 $/Mwh
Step 1	0 to 5%	50
Step 2	5% to 10%	100
Step 3	10% to 15%	150
Step 4	15% to 20%	250
Step 5	20% to 25%	500
Step 6	Over 25%	1000

New Generating Resources

A variety of promising generating options were evaluated during preliminary studies. Natural gas-fired combined-cycle combustion turbine plants were consistently chosen by Aurora for all new plant additions in Medium and Low forecasts. Though High forecast assumptions also resulted in a preponderance of new gas-fired combined-cycle power plants, some additions of advanced-technology coal-fired power plants, wind turbines and simple-cycle gas turbines were observed. Preliminary studies also indicated that over the study period, market prices gravitate to the fully allocated cost of new capacity additions, as would be expected. Because new capacity additions are largely comprised of natural gas-fired combined-cycle power plants, an effort was made to develop plausible and consistent assumptions regarding the evolution of the cost and performance of these plants over the study period.

A review of planned and recently completed combined-cycle power plants concluded that a typical 250 MW class plant entering service in 1997 costs about $550/kW to construct. This cost is probably below market equilibrium level. The construction costs of large combined-cycle plants have declined up to 40 percent in recent years. Though much of this decline is attributable to improvements in engineering, manufacturing and construction, part results from a slow market for new generating capacity and excess manufacturing and construction capacity. Current prices are therefore considered representative of Low forecast conditions. The Medium forecast base year capital cost is assumed to be 10 percent higher than current prices. For the High forecast, base year capital cost is assumed to be 10 percent greater than Medium costs.

Continuing advances in aerospace gas turbine applications are expected to lead to further reduction in the cost and increases in the efficiency of power generation equipment. For this study, cost reduction assumptions are based on projected improvement in gas turbine specific power . Increases in specific power produce greater output with no increase in physical size, thereby reducing cost. Historical rates of improvement and estimated ultimately achievable rates of specific power suggest that over the study period specific power will continue to improve, on average, at constant rates. The resulting projections of annual cost reduction averaged - 0.6 percent in the Medium forecast, -1.2 percent in the Low and - 0.1 percent in the High. These reductions were applied to both capital and operating costs.

State-of-the-art combined-cycle efficiency is closer to forecast ultimate efficiency than is specific power. Efficiency is therefore forecast to continue to improve, but at declining rates. Rates of efficiency improvement are based on alternative introduction dates of advanced turbine technologies, and decades by which ultimate turbine efficiency might be achieved. Using this approach, combined-cycle plant efficiencies would improve from 48 percent in 1997 to 54 percent by 2020 in the Medium forecast, to 57 percent in the Low and to 53 percent in the High .

Financing

Future plants are assumed to be developed by independent power producers. Some plants may continue to be developed by consumer-owned utilities and a few may yet be developed under conventional investor-owned utility regulation. But it is likely that independent firms will develop the majority of new plants, especially during the period following 2007 when surplus capacity has disappeared and development of new capacity is forecast to resume.

In the past, the certainty provided by long-term power sales contracts allowed independent developers to secure project financing at debt ratios of 80 percent, or greater. High debt leverage lowered the cost of servicing the capital investment. Future plants, however, are increasingly likely to sell to the wholesale market without the certainty of long-term contracts. Some expect lenders to demand additional equity investment to compensate for this added market risk. Others argue that the substitution of balance sheet (company) financing for convention non-recourse project financing, the increasing size of independent power development firms and increasing lender experience with merchant plant operations will allow continuation of highly leveraged debt financing. There has been some indication that merchant plant equity requirements will not greatly differ from that of conventional non-recourse project financing. This, however, may be attributed to the weak power plant market providing limited investment opportunities. Because of these uncertainties we chose to somewhat increase our assumptions regarding the equity share of new project financing to 30 percent in the Medium forecast. This yields a 6.3 percent annual after-tax cost of capital. High forecast assumptions include a 40 percent equity investment, yielding a 7.5 percent real annual after-tax cost of capital. Low forecast assumptions assume a continuation of 20 percent equity financing, yielding a real annual after-tax cost of capital of 5.2 percent.

Corporate discount rates equal to the after-tax cost of capital are used in this study to calculate the present value of investment options. After-tax cost of capital discount rates would likely be used by power plant developers when assessing investment opportunities, and therefore should generally mimic real world project development decisions. These discount rates are higher than those used in most earlier council studies that used a societal perspective.

Fuel Prices

Natural Gas

Fuel prices are an important assumption in Aurora because they determine, to a significant degree, the variable operating cost of many of the resources that are on the margin and therefore establishing market clearing prices. Since in most forecasts the long-term market price tends to equate to the full cost of a gas-fired combined cycle combustion turbine, the price assumptions for natural gas are particularly important.

Aurora develops its natural gas price assumptions based on two pricing points, Henry Hub in Louisiana and Permian Basin in Texas. Prices in the Aurora regions are then based on a series of differentials from these trading hubs. There are three basic assumptions that need to be specified to provide all of the natural gas information:

- Starting prices for 1997 at the two pricing hubs;
- A series of basis differentials to develop regional prices; and
- Escalation rates for prices at the two market hubs.

The starting natural gas price for the Aurora analysis should be close to an equilibrium price under normal weather conditions. Actual prices for 1997 are not a good starting point because gas prices were at a cyclically high level in 1996 and 1997. Henry Hub spot prices averaged $1.78 per million Btu from 1989-95 but extraordinarily high prices in February and March of 1996 sent the average 1996 price up to $2.76. Prices remained relatively high during the winter of 1996-97 and the average 1997 price is estimated to be around $2.50.

We assumed a starting Henry Hub price of $2.00 for the medium case. This is about equal to the average price between 1989 and 1997. This level recognizes some upward trend in Henry Hub spot natural gas prices in the past ten years and is probably more representative of a long-term gas price level for 1997. To reflect the uncertainty about what normal prices would have been in 1997, we used $1.80 for the low case and $2.25 for the high case. Permian prices are typically less than Henry Hub prices. Between 1989 and 1995

Permian prices averaged $0.11 per million Btu less. However, the differences had been increasing toward the end of that period and were about $0.22 in 1994 and 1995. In 1996 with the large increase in Henry Hub prices the difference was $0.45. For this analysis we assumed a difference of $0.20 so that the 1997 Permian price in the medium case is $1.80 per million Btu.

The natural gas price differences from Henry Hub and Permian to the other Aurora regions were estimated by examining various sources of historical data. The largest regional gas price differentials, and the most important for the Pacific Northwest are the lower prices associated with Canadian and Rocky Mountain gas supplies. The choice of a typical value for this difference is also confused by the very volatile and unusual patterns of the past few years. Canadian prices at the B.C. border at Sumas were typically $.030 to $0.60 lower than Henry Hub prices until 1996. When Henry Hub prices increased in February 1996, Western Canadian and Rocky Mountain, prices did not. As a result the differential in prices increased to $1.38 on an annual basis in 1996. When Henry Hub prices peaked again in December 1996, Canadian prices increased even more causing the differential to drop to near zero in that month. Clearly these markets were not in equilibrium in the last two years. The beginning differentials for this study are based on the period shortly preceding 1996.

The regional price differences for Canadian gas supplies are complicated by another fact. In 1999 and 2000, significant pipeline expansions will increase the capacity to export natural gas from Alberta to the East. This expanded export capacity likely will have the effect of increasing prices in Alberta and British Columbia, perhaps significantly. To reflect this we have assumed that the basis differential from Canadian markets to Henry Hub decreases over the next several years in the Medium and High cases. The price differential between Henry Hub and the AECO Hub price in Alberta decreases from $-0.65 to $-0.45 by the year 2001. The Sumas differential decreases from $-0.55 to $-0.40 during the same period. These differential decreases result in significant increases to Northwest natural gas prices in the early years of the analysis. In the Low case we assumed that supply could expand rapidly enough in Alberta that the Canadian gas prices would remain depressed relative the U.S. gulf coast. In the high case, we assumed that the price differential could fall to much lower levels.

The third assumption for natural gas prices is the escalation rate applied to Henry Hub and Permian prices. For the medium case, we assumed the medium gas price escalation included in the Council's draft power plan, 0.8 percent per year escalation above general inflation. In the low case, a real escalation rate of -1.0 percent per year was used, and in the high case a 1.5 percent real escalation was assumed. The table below summarizes the natural gas price assumptions that are most related to the Pacific Northwest electricity market. Figure 4 shows the resulting range of gas price assumptions for the Pacific Northwest.

	Low	**Medium**	**High**
1997 Price Henry Hub	$1.00	$2.00	$2.25
Permian	$1.60	$1.80	$2.15
Basis Differential AECO	-0.65 constant	-0.65 down to ?0.45	-0.65 down to ?0.20
Sumas	-0.55 constant	-0.55 down to ?0.40	-0.55 down to ?0.10
Escalation rates Real	-1.00%	0.80%	1.50%
Nominal	1.47%	3.32%	4.04%

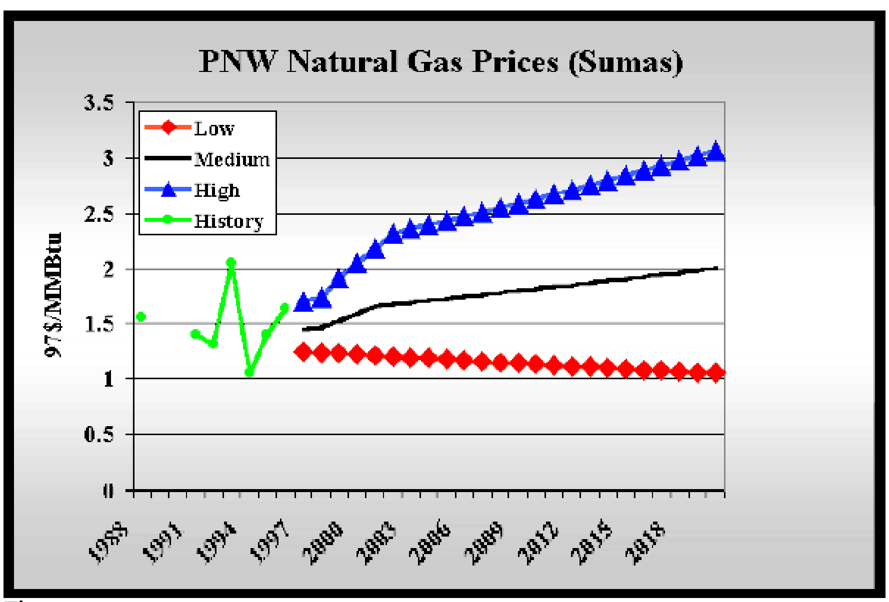


Figure 4

Coal

The other fuel, besides natural gas, that plays a significant role in the market price of electricity is coal. Coal prices are assumed to decline in real terms in the base and low cases and to remain constant in the high case. In the low case coal prices are assumed to decline by 2 percent a year. In the base case, they decline at 1 percent a year.

Inflation

General inflation is assumed to continue at a moderate annual average rate of 2.5% over the study period in all scenarios. While greater than the current rate of inflation, this rate is less than the average rate of 3.7 percent experienced over the past 50 years, and lower than the 3.5 percent rate used in the Council's draft Fourth Northwest Conservation and Electric Power Plan.

Many of the important prices and costs used in the study are expected to change at rates differing from the general rate of inflation (i.e., at positive or negative real rates of inflation). Among these are fuel prices, capital and operating costs of new generating capacity and the operating costs of existing generating capacity. For example, the price of natural gas, the fuel most significantly affecting the conclusions of this study, has declined in recent years, chiefly due to industry deregulation, improved exploration and production technology and development of large western Canadian reserves. Continued market pressure and improvements in exploration and production are expected to hold real natural gas price increases to low levels, even with a likely increase in demand. Natural gas prices are assumed to increase at annual real rates of 0.8 percent in the Medium case and 1.5 percent in the High case, and to decline at 1.0 percent less than general inflation in the Low case.

The inflation-adjusted capital costs of new generating technologies are expected to decline due to continuing technological innovation and economies of production. For example, continuing increase in the specific power and other technological improvements to combined-cycle gas turbine technology are expected to lead to average annual real capital cost reductions over the study period of 0.6 percent in the Medium case, 1.2 percent in the Low case and 0.1 percent in the High case. Similar equipment vintage-related reductions of operating costs are also expected. In addition, economic pressures, brought about by industry deregulation and restructuring are expected to lead to additional market-driven reduction in operating costs, as owners of both new and existing power plants seek to improve the efficiency of plant operations. These declines are forecast to be 2.5 percent annual real in the Medium and Low cases and 1.25 percent annual real in the High case, continuing through 2004.

The Price Forecasts

Aurora studies were performed for three market price forecasts using the demand, technology, and fuel price assumptions discussed previously. A summary of the resulting market price forecasts is shown in Figure 5. These prices are forecasts of annual prices at Mid-Columbia, and are shown in nominal dollars (the effect of inflation is included). They represent the average price associated with a 100 percent load factor, seasonally flat purchase or sale under average water conditions. Network charges for delivery within the Pacific Northwest are not included in the price.

Figure 6 shows the same three price forecasts in constant 1997 dollars (the effect of inflation has been removed). The general price patterns here are informative. In the short term, (e.g. next 5-7 years) prices tend to be influenced mostly by the size of the WSCC surplus and fuel prices for existing resources. The high comes up faster because demand grows faster, reducing the size of the surplus, and natural gas prices start higher and escalate more quickly.

In the long term, prices will tend to settle at the price of the most cost-effective combination of new resources. In both the low and medium forecasts, combined cycle combustion turbines are the only new resources added, and in the high, they make up the bulk of new resource additions. In all three forecasts, after about 2005, the prices roughly track the fully allocated cost of new combined cycle under the technology and fuel price assumptions in each forecast. Just as in traditional integrated resource planning, in the long run, market dynamics should work to keep prices at a level that just recover resource costs plus the required profit margin for investors. Long term average annual prices range from about 13 $/mWh in the low to about $35 $/mWh in the high, in constant 1997 dollars.

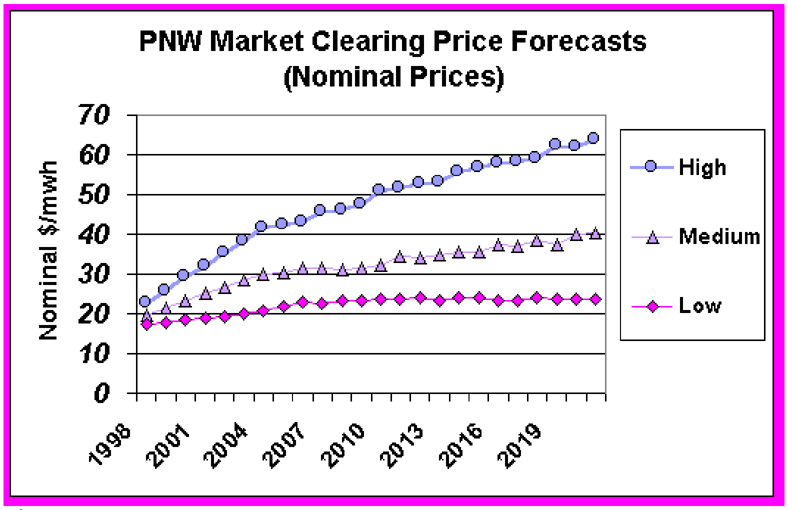


Figure 5

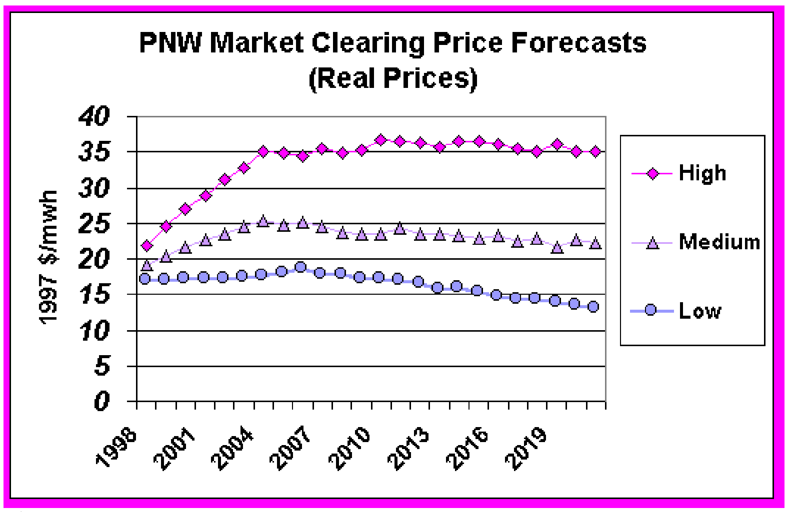


Figure 6

Seasonal and Diurnal Variation

The annual prices shown above are averages for the hourly prices in any given year. Monthly on and off-peak prices results through 2010 for the medium case are shown in Figure 7. These prices are based on average NW hydro conditions. The prices exhibit strong seasonal and diurnal variation, with patterns changing through time as the supply/demand balance is adjusted for demand growth and changes in WSCC resources. The integration analysis, discussed later, uses prices like those shown in Figure 7 to determine the market value of Bonneville capacity and energy through time.

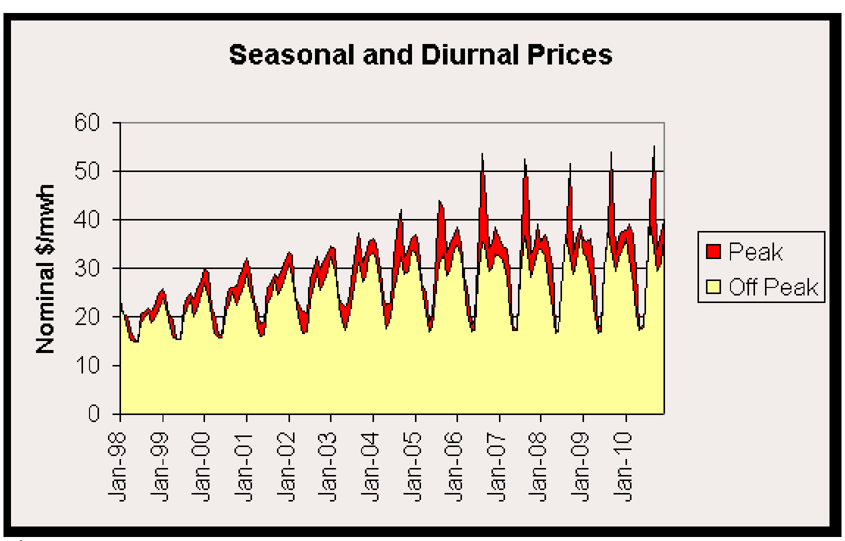


Figure 7

Reserve Margins

WSCC peak hourly demand and generation nameplate capacity for the month of August as developed by Aurora for the medium case is shown in (Figure 7b). The chart shows current WSCC capacity reserves on the order of 40 GW, generally declining through a combination of demand growth and unit retirement until it stablizes at about 24 GW in 2006. About 3.200 GW of exisiting capacity is retired in the 2001 to 2006 time frame. New capacity additions in this forecast consist entirely of combined-cycle combustion turbines, about 31 GW over the last 15 years of the study. About 7GW of this new capacity is sited in the Pacific Northwest.

WSCC reserve margins (the ratio of capacity reserve to peak demand) stabilize at about 16% in this forecast. This is the point of economic equilibrium reached in the model when balancing the cost of new resource capacity against the customer demand reduction alternatives described earlier. Either higher resource costs or cheaper demand-side alternatives would lead to lower reserve margins in this forecast. The converse is true of either lower resource costs or more expensive demand side alternatives.

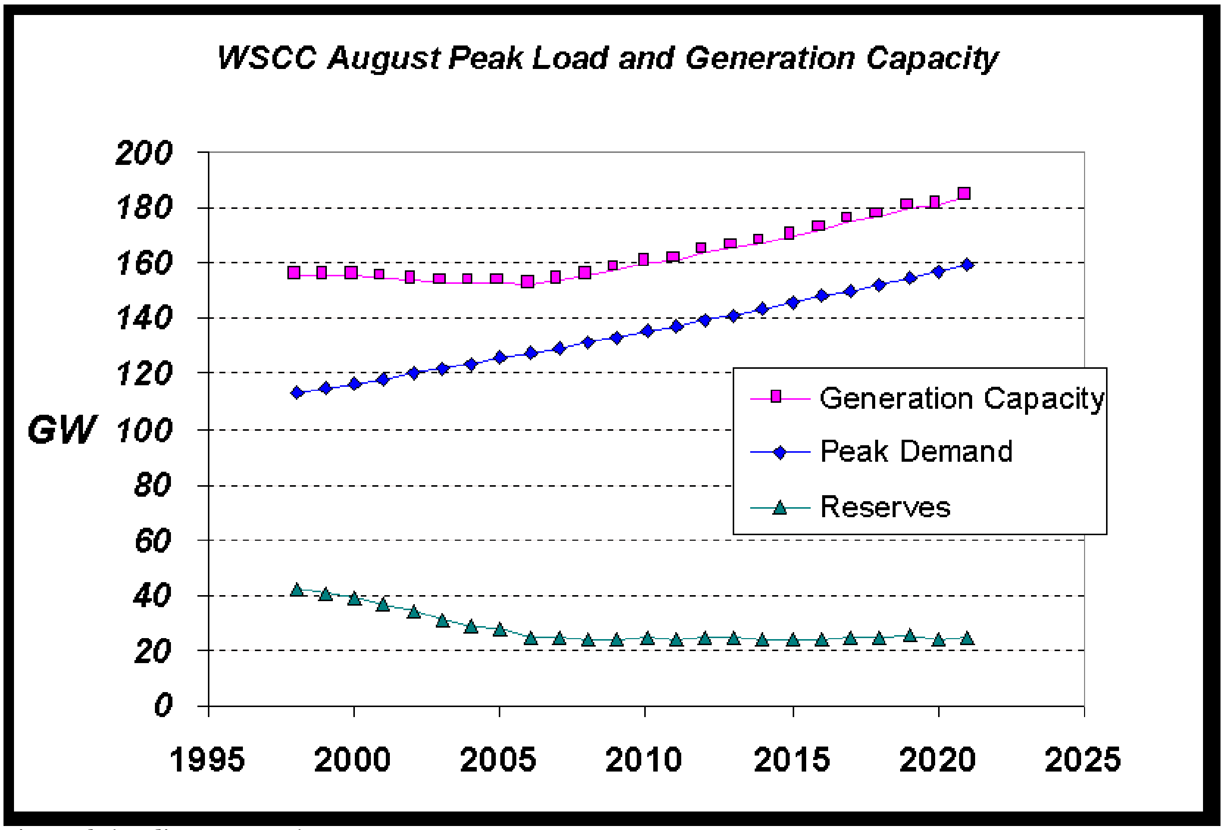


Figure 7b (Medium Forecast)

Effect of Generation Losses on Market-Clearing Prices

One further point on market prices. Studies were also done to look at the potential impact on market-clearing prices of the removal of the four Lower Snake dams and John Day. This represents a reduction in Bonneville's hydro generation capability of approximately 2300 megawatts on average and 5200 MW of capacity. The projects were removed in the 2004 to 2008 time frame. While there were minor price changes during the dam removal period, the long term effect on market clearing-prices was neglible. In the model, as the projects were being taken out, the energy was replaced with new combined cycle, leaving marginal prices, which are those associated with the most expensive plants that have to operate, essentially unchanged. This is a reasonable outcome. If drawdowns do become a reality, it will present a market opportunity for resource developers. Because the changes to prices were so minor, the same sets of market prices were used for all system configuration scenarios in the integrating analysis.

It's important, however, to understand that dam removal having little effect on market prices does not mean that it has little effect on Bonneville. In the drawdown scenarios, Bonneville loses large amounts of capacity and energy, and this translates through market prices into significant reductions in the value of Bonneville's production and significant increases in Bonneville's cost per unit of production.

Limitations of the Analysis

Aurora simulates the operation of a fully competitive electricity market throughout the West. For several reasons, discussed below, the actual operation of the Western electricity market will differ from the simplified market model. This section discusses some of the ways in which Western electricity markets are likely to vary from Aurora's simplified assumptions and structure.

The first important limitation is that Aurora models a competitive market. Although the Western electricity system is moving toward a fully competitive structure, it may be several years before that transition is complete. Or it may, in fact, never be complete. Owners of electricity generating plants are likely to be selling into both regulated and competitive markets for some time. The fact that much of a plant's electricity may be sold into regulated markets to serve captive customers, may affect the price at which any remaining electricity would be offered to the competitive market. Plants that would be retired in a competitive market because they couldn't cover their fixed operating costs over long periods of time may remain operating because their fixed cost recovery is aided by regulated pricing to captive customers. In this analysis we have constrained the rate at which generating units can be retired in an attempt to better simulate the possible nature of industry transition.

Aurora prices all electricity production at the market clearing price on an hourly basis. As noted above, not all electricity will be sold in competitive markets as long as regulated markets remain. In addition, electricity may not always be sold on an hourly basis. Currently there are various types of electricity sales. For example, electricity may be sold on an annual or monthly basis at a fixed price. Capacity may be sold separately from energy to assure peak supplies are available. Electricity may be sold on an interruptible or firm basis. As long as there are active hourly markets for electricity, the pricing of these other products should be strongly related to the hourly values of electricity. Even if the pricing of these products evolves in a different way, the overall value must approximate the cost of new generating resources. The average prices of electricity on an annual basis should be relatively unaffected by different contractual forms of electricity sales. Since the focus of this analysis is on average annual market prices, this limitation should not affect the conclusions.

Another limitation is that Aurora assumes that investors have perfect foresight of market clearing prices in the future as they contemplate building generating capacity. In reality, of course, investors will estimate future prices. Each investor may have different expectations and therefore will reach different conclusions. In addition, some investors may have strategies that involve other decision factors than just expected future earnings. One example, might be an investor who is willing to overbuild capacity in the short run in order to gain market share in the future. Other investors may think they can create market power in a particular area by building extra capacity or retiring capacity. Modeling limitations are likely to result in a smoother pattern of future prices than the actual market is likely to achieve. Most commodities tend to go through cycles of over and under-supply and electricity is not likely to be different. The real electricity market is likely to experience price cycles of several years' duration, in addition to the hourly and seasonal cycles that the model captures quite well.

Aurora does not include a price feedback effect within the model. Although the demand side peaking resources are one type of demand response to price, there are likely to be other changes in the level and shape of demand as prices change over time and among scenarios. It is not currently practical to include such price effects into a model like Aurora. If demand response could be captured, it would likely show that as electricity pricing increasingly reflects hourly price patterns, the shape of demand would become flatter. This would tend to reduce competitive electricity prices by reducing the reserve margin and their associated costs.

A final concern of several members of the oversight group was the future reliance on gas-fired generation implicit in these results. The model would develop 31 GW of additional gas-fired capacity over the next 20 years. Some question whether it is prudent to assume that level of increase in gas use without a greater impact on gas prices than is reflected in the forecasts used in the model. The gas price forecasts generally take into account expectations of significantly increased gas use in electrical generation. None-the-less, there is an "all the eggs in one basket" aspect which is of discomfort to some members of the oversight group.

Bonneville's Non-Fish and Wildlife Costs

Much of the focus of this analysis is on the interaction of possible future market prices for electricity with the costs of possible fish and wildlife mitigation measures. The costs of those measures, however, are in addition to Bonneville's basic costs. Those basic costs are themselves a variable that can be affected by policy choices and management efficiency.

Bonneville's Basic Costs

For the purposes of this analysis, the basic costs of interest are Bonneville's Power Business Line (PBL) costs exclusive of fish and wildlife costs, transmission, and operating costs of Washington Public Power Supply System Plant 2 (WNP-2). Operating costs for the Supply System's Plant 2 are treated separately. The basic costs include debt service on the federal projects; debt service on the Washington Public Power Supply System net-billed projects and other projects financed by third party debt, operations and maintenance costs (O&M) for the Corps of Engineers and Bureau of Reclamation projects and Bonneville's normal operations costs - personnel, goods and services. Transmission costs are not included since in the restructured wholesale power market, the costs of Bonneville's transmission should not enter into the consideration of the competitiveness of Bonneville's power products.

This analysis considered two forecasts of Bonneville's basic costs. The first set was the product of Bonneville internal budget planning carried out in the summer and early fall of 1997. This effort identified budgets for the FY 2002 - 2006 period that are roughly $80 million per year less than the average annual budget included the 1996 rate case. This set of costs is referred to as the PBL Baseline. Subsequently, the Northwest Power Planning Council and Bonneville convened a Cost Review that involved private sector experts in management and finance. This effort yielded recommendations for about an additional $80 million reduction in annual expenses in the FY 2002 - 2006 time frame, exclusive of reductions in transmission costs. These reductions have been extrapolated out through the time frame of this analysis. This information is shown on Figure 8. This figure clearly illustrates the reduction in basic expenses that begin in 2013 as the third party debt begins to be paid off.

The cost represented by the PBL Baseline and the additional reductions embodied in the recommendations of the Cost Review represent the effects of a combination of both management efficiencies and policy choices (e.g., continuation of general transfer agreements, the termination of the residential exchange). The pace at which they can be implemented and, indeed, the degree to which they can be fully implemented is subject to some question. By the same token there may be other efficiencies that have not yet been identified. For the purposes of this study, the PBL Baseline was used for most of the analyses with the additional Cost Review reductions used as a sensitivity test.

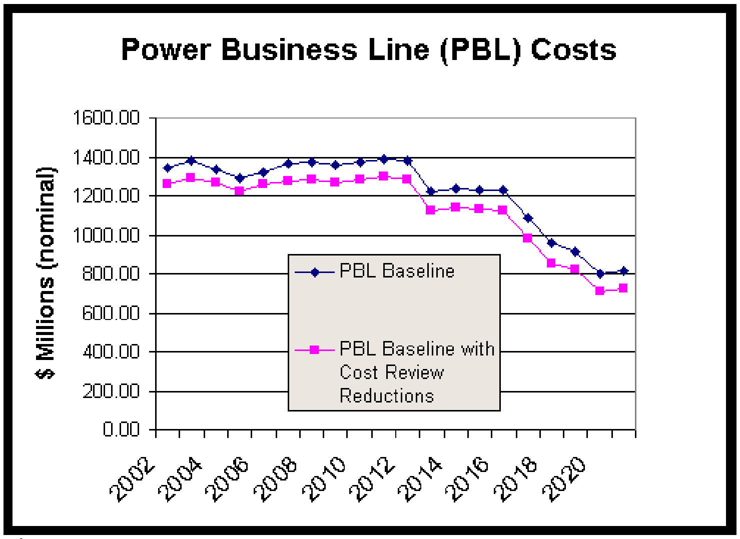


Figure 8

WNP-2 Operation and Maintenance Costs

The Supply System has been under great pressure to reduce WNP-2 operating costs to levels sustainable by the current wholesale power market. Though most aspects of the current WNP-2 ten-year operating budget are generally consistent with industry norms, the budget deviates significantly with respect to capital replacement costs. The forecast capital replacement budget declines to $3.9/kW by 2003, then remains constant in real terms. Energy Information Administration staff, who have been closely monitoring nuclear plant costs, believe that a boiling water reactor such as WNP-2 would currently require a capital replacement budget averaging $30/kW year. This budget would escalate at 2 to 3 percent annually to compensate for aging-related equipment failures.

The adequacy of the current $4 million annual decommissioning fund contribution is also open to some question. This contribution requires an average real rate of return on reinvestment of 6.3 percent over the remaining license life of the plant to cover the estimated cost of "Safe Store" decommissioning - the approach having the lowest present value cost. Historically, U.S. decommissioning funds have returned negative rates on investment. Though WNP-2 has fared better, a 6.3 percent real return on reinvestment appears optimistic.

These aspects of the current WNP-2 budget lead staff to prepare two long-term operating budget forecasts (Figure 9). Each assumes that the plant will continue to operate at a 75 percent capacity factor until license expiration in 2024. One alternative, following the current budget through 2007, is intended to weather a period of low power prices and extraordinary Bonneville cost obligations. Following 2007, the capital replacement budget returns to a level consistent with EIA estimates. A five-year plant rehabilitation is also assumed to occur, costing in total an amount equal to the capital replacement costs deferred through 2007. Decommissioning fund contributions are increased to a level covering the estimated Safe-Store decommissioning costs with an average 3% real return on investment.

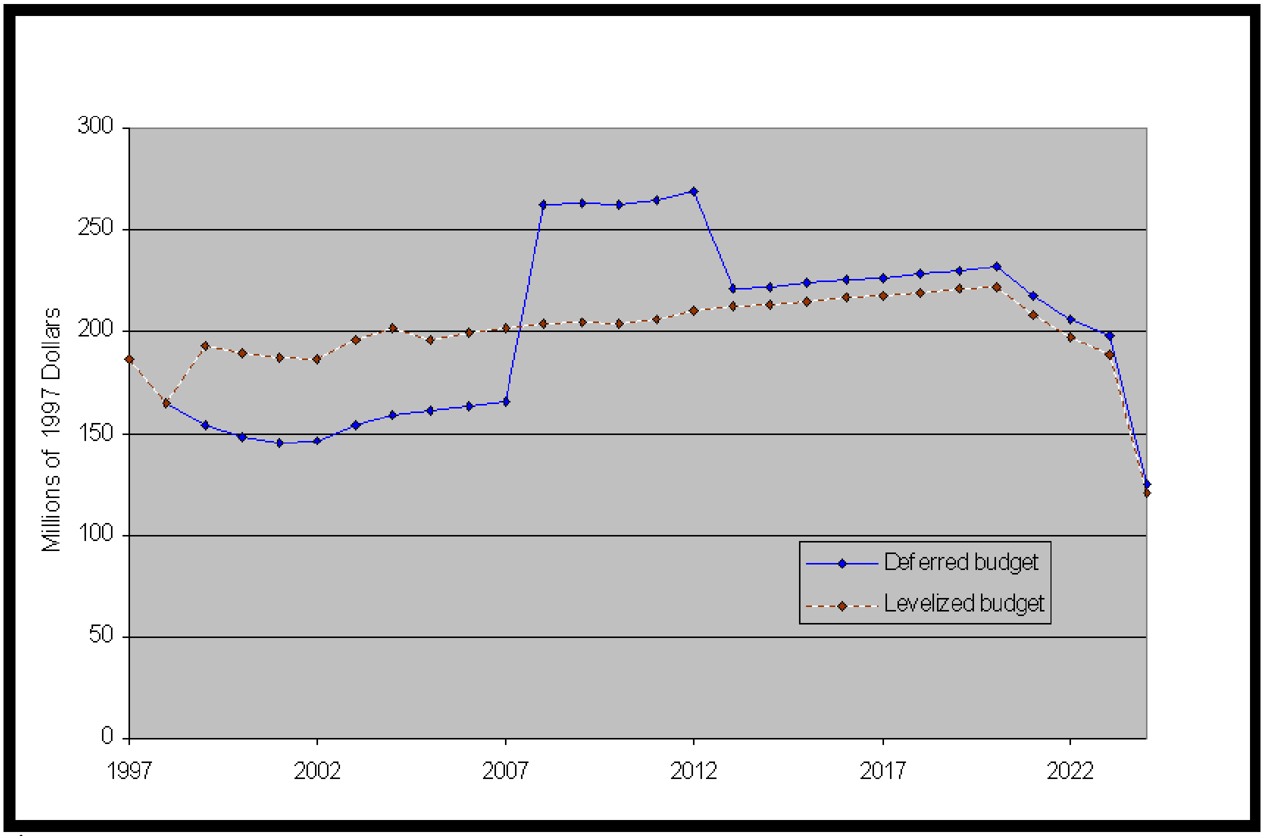


Figure 9

WNP-2 Operating Budget Alternatives

The second alternative assumes that while the reductions in fixed operating and maintenance costs of the current budget forecast are feasible, capital replacement costs consistent with EIA estimates are required on average to maintain plant reliability. Decommissioning fund contributions are also immediately increased to ensure coverage of Safe Store decommissioning costs with a 3 percent average return on investment.

Fish and Wildlife Scenarios

A number of fish and wildlife mitigation scenarios were evaluated for their potential impact on Bonneville's financial condition. The objective was to have a set of scenarios that spanned the range of expenditure patterns and operational impacts associated with the salmon mitigation alternatives that are being discussed in the region. The scenarios consist both of an operational strategy, defined through flow targets, spill policy, and future system configuration changes, and also an expenditure strategy in terms of capital, direct program, and O&M expenditures. Five separate operational/system configuration strategies were evaluated, and three of these were also evaluated assuming implementation of Clean Water Act measures for a total of eight scenarios.

The Scenarios

The fish and wildlife mitigation scenarios considered were:

- **? Reduced flow augmentation -** This scenario relaxes current flow augmentation in the Snake and Columbia rivers. Flow augmentation levels are equal to those specified in the Council's 1984 Fish and Wildlife Program. Spill levels are equal to those in the National Marine Fisheries Services' (NMFS) 1995 biological opinion, except that no spill is provided at collector dams. This scenario also assumes no new capital investment for fish and wildlife beyond that already committed and only inflationary increases in other costs.
- **1995 Biological Opinion (BiOp)** - From an operational standpoint, this scenario reflects current river operation as prescribed by the NMFS' 1995 biological opinion. This is equivalent to case A1 in the Corps' Drawdown Feasibility Study. This scenario also assumes no new capital investment for fish and wildlife beyond that already committed and only inflationary increases in other costs.
- **Transportation Plus** - From an operational standpoint, this operation is identical to the 1995 BiOp except that it provides no spill at collector dams. Emphasis on transportation is increased. This scenario involves additional capital costs for transportation and significant increases in direct program costs.
- **Transportation Plus with Clean Water Act (CWA) Measures** - This scenario is the same as transportation plus from an operational standpoint. It adds to the Transportation plus scenario considerable capital investment in dissolved gas abatement and temperature control measures to comply with Clean Water Act standards. The cost estimates for CWA implementation are preliminary.
- **Drawdown of the four Lower Snake River dams to natural river** - This scenario implements a natural river drawdown of the

four lower Snake River dams. Flow augmentation in both the Snake and Columbia rivers is the same as current (BIOP) operations. This is equivalent to case A3 in the Corps' Drawdown Feasibility Study. The operational impacts are those associated with loss of generation capacity and storage at these dams. There are also significant capital costs associated with bypassing of the dams as well as the higher direct program costs incorporated in the Transportation Plus scenario. However, Clean Water Act compliance measures are not included. The financial analysis assumes half the generation capacity goes out of service in 2004 with the remainder lost in 2006.

- **Drawdown of the four Lower Snake River dams plus John Day to natural river** - This operation incorporates a natural river drawdown of the four lower Snake River dams and John Day dam with current flow augmentation in both the Snake and Columbia rivers. This is equivalent to case B1 in the Corps' Drawdown Feasibility Study. This scenario involves further loss of generation capability and storage compared to the previous scenario along with additional capital costs for bypassing John Day. The financial analysis assumes the generating capacity at John Day goes out of service in 2008.
- **Drawdown of the four Lower Snake River dams plus John Day to natural river and Clean Water Act Measures** - This is identical to the previous scenario operationally but includes additional capital costs for Clean Water Act compliance measures.
- **Drawdown of the four Lower Snake River dams plus John Day to natural river, increased flow augmentation and Clean Water Act Measures** - The final scenario implements a natural river drawdown of the four lower Snake River dams and John Day dam with enhanced flow augmentation. This alternative assumes that Canadian storage will be used for flow augmentation and that all fish related drafting limits are relaxed. This alternative violates the Columbia River Treaty. This scenario also incorporates the capital costs associated with Clean Water Act compliance measures.

None of the alternatives considered intermediate flow augmentation regimes between the current BiOp and the increased flow augmentation in the last alternative.

Operational Impacts

Each of the river operation and system configuration alternatives affects the federal power system's ability to produce electricity. The impacts can affect both the amount of energy the system is capable of producing and the temporal distribution of generation. This section discusses changes to the annual average and monthly energy generating capability of the five scenarios which cause changes in production capability. The operational impacts of the various scenarios were determined using the System Analysis Model (SAM) to analyze the productive capacity of the system under the flow, storage and other constraints associated with each scenario. Only the operational impacts on the federal system were considered. Most of the impacts are on the federal system but there are other operators that would also be affected.

Figure 10 illustrates the change in annual average energy production for each scenario relative to current operations. The energy losses shown in Figure 10 represent a real reduction in generating capability and are mostly the result of spill or dam bypass.

In the past, regional planners often described impacts to the hydroelectric system in terms of the loss of "firm" generating capability. Firm generating capability, in simple terms, is defined as the amount of energy that the hydroelectric system can produce during the worst sequence of historical water conditions. Recently, as the West Coast Market and access to transmission has opened up, this concept is diminishing in importance. In an open market environment, the important parameters to assessing the revenue generating capability are the annual and monthly energy generating capability and the amount of flexibility the system has to shift generating capability from light demand hours (night) to high demand hours.

The Reduced Flow and Transport Plus operations show a slight increase in generating capability. Relative to current operations they represent about a 2 percent and 0.5 percent increase in the Federal generating capability, respectively. The Lower Snake Drawdown scenario represents a 12 percent loss. Adding John Day Drawdown (LS & JD Drawdown) increases the loss to 25 percent and, finally, adding enhanced flows (LS & JD DD, High FA) further increases the loss to about 35 percent of the Federal generating capability.

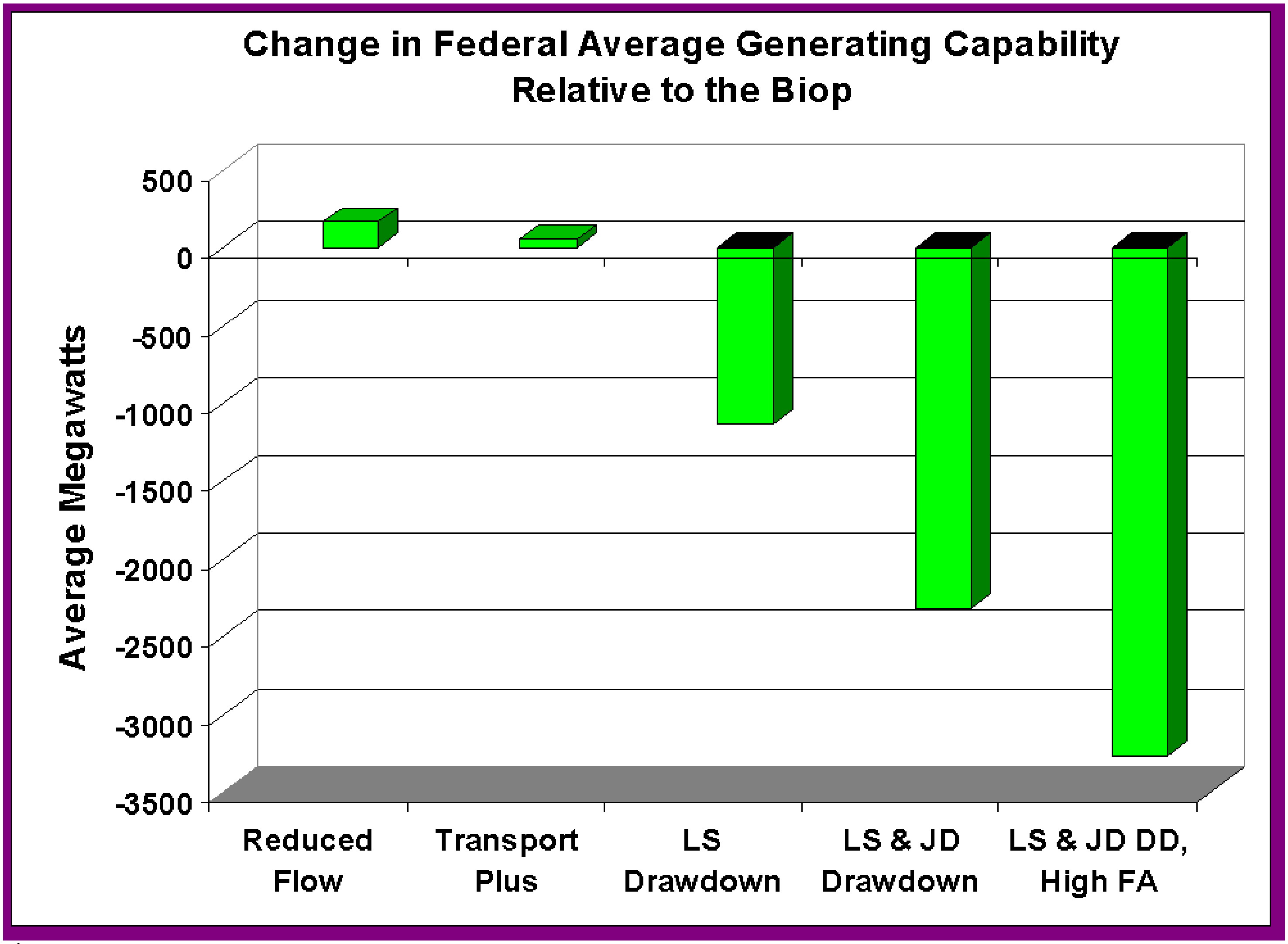


Figure 10

These losses are averaged over the historical 50-year water record from 1929 to 1978. Losses for any given year will depend on precipitation, snow pack and weather. For the Lower Snake Drawdown operation, for example, the average annual loss is about 1,136 average megawatts but that number will range from a low of about 700 (wet years) to a high of 1,500 (dry years).

The annual averages give only a partial picture of the effect on federal generation capability. Each scenario above will also change the shape of monthly generating capability. For the Lower Snake Drawdown case, the average annual energy loss is about 1,136 average megawatts but for April, May and June the average loss is over 2,000 megawatts per month. For the Lower Snake and John Day drawdown, the average annual loss is about 2,320 average megawatts but for April, May and June the average loss is over 3,500 megawatts. For the most extreme case above, the average annual loss is about 3,274 average megawatts but, unlike the other drawdown scenarios, the peak loss occurs in January and averages over 5,000 megawatts. The effects of this change in shape of production are captured in the Aurora market analysis in terms of the effect on market prices. The reduction in potential revenue capability for the federal system is captured in the integration analysis discussed later in this report.

"Non-Operational" Costs

Implementation of any of these scenarios has non-operational costs in addition to whatever operational impacts they may have. The kinds of costs considered to be non-operational costs were:

- **Capital costs** - for example, these include the costs of modifications to dams for dissolved gas abatement, new barges for transport of juvenile salmon, surface collection facilities, and, in the case of draw down scenarios, the cost of by-passing or breaching the dams. The costs are assumed to be capitalized and have been turned into a repayment stream as they would appear in Bonneville's revenue requirement. The sources of the estimates of these costs have been the responsible agencies, e.g., the Corps of Engineers. They have been aggregated by an interagency committee working under the auspices of the Three Sovereigns Process.
- **"Reimbursables"** - these are the O&M costs of the Corps and Bureau of Reclamation and the U.S. Fish and Wildlife Service related to the fish and wildlife scenarios that are reimbursed by Bonneville. The sources of these estimates are again the responsible agencies as aggregated by the Three Sovereigns committee.

- **Direct Program** - The direct program costs are costs for activities like habitat restoration, screening, hatchery operation and so on operated by state and federal fish and wildlife agencies and the tribes. The source of these estimates is the Columbia Basin Fish and Wildlife Authority.
- **Transmission** - The removal of the generation at, in particular, John Day dam and the four lower Snake River dams is expected to have a degrading effect on the stability and transfer capability of the transmission system. Bonneville Transmission engineering staff are analyzing the costs of addressing this problem. At present, the estimates range broadly from $30 million to $230 million (one time cost) each for John Day and for the four lower Snake dams. For this analysis, a one time cost (capitalized) of $130 million has been assumed ($130 million for the four lower Snake dams and an additional $130 million for John Day). These costs are included in the capital costs of those scenarios.
- **Avoided Costs** - In those cases where dams are taken out of service, there are planned capital and O&M costs for those facilities that would no longer be incurred. In those cases, these costs have been netted out of the total cost of the scenario. What's Not Considered? This analysis is focused on the costs to the federal power system. It does not consider the effects on the non-federal projects on the Snake and Columbia. It also does not consider non-power effects. For example, economic impacts on irrigation, navigation, and recreation are not considered. Efforts to estimate economic mitigation costs are ongoing. By the same token, the possible benefits of increased salmon populations that could result from the measures undertaken have also not been considered. Total Non-operational Costs of the Scenarios The non-operational costs of each of the scenarios over time are illustrated in Figure 11.

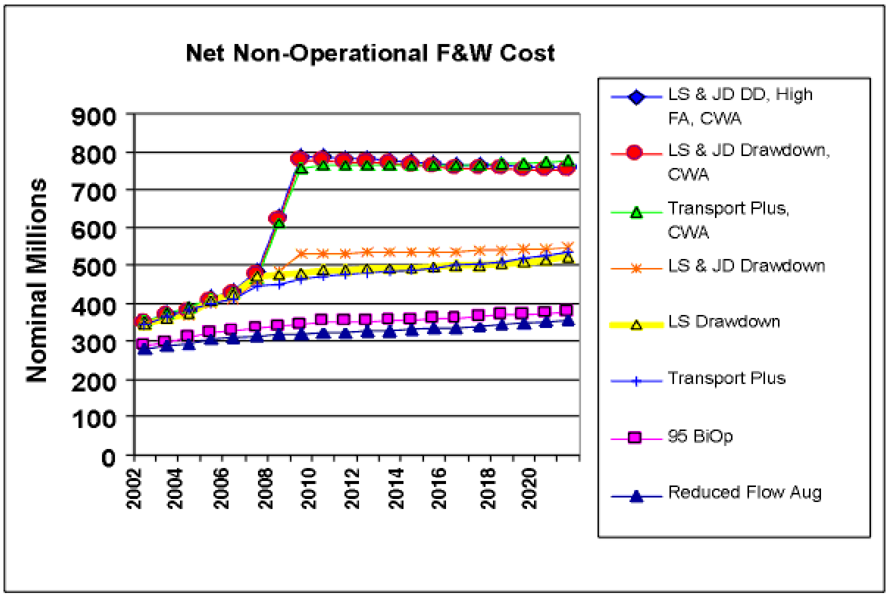


Figure 11

As figure 11 illustrates, the scenarios break down into three "families." The reduced flow augmentation and BIOP alternatives are the lowest cost. The Transport Plus and the two draw down scenarios without Clean Water Act compliance measures are the next highest. These incorporate higher direct program costs, accounting for the higher costs in the early years of the study period, and additional capital costs. In the case of Transport Plus, the capital is for barging facilities. In the case of the draw down scenarios, the additional capital costs are for bypassing of the dams. It should be noted, however, that the drawdown scenarios also have significant operational impacts as shown in Figure 10. The last group of scenarios involves the addition of Clean Water Act compliance measures to the Transportation plus, the five-dam draw down and a five-dam drawdown scenario with increased flow augmentation. In the draw down scenarios, the cost of Clean Water Act compliance is reduced because those measures are not required at the breached projects. Again, although the non-operational costs of this group of scenarios are similar, there are large differences in the operational impacts.

Combined effect

The combined effect of the operation impacts and the direct dollar costs are best illustrated by looking at Bonneville's average system cost. This is nothing more than Bonneville's total cost divided by its average annual generation capability. Figures 12-a and 12-b show average system cost in nominal and real terms. Figure 12 clearly illustrates the significant effect of the loss of generation associated with the drawdown scenarios. Whereas the "Transport Plus, CWA" scenario has direct dollar costs that are the largest of any of the scenarios, its effect on average system cost is only in the middle of the pack.

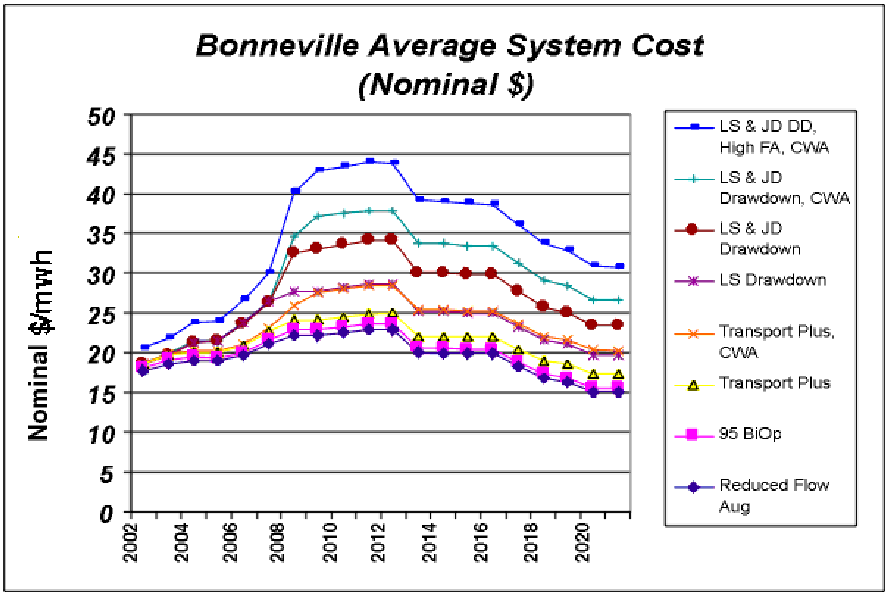


Figure 12a

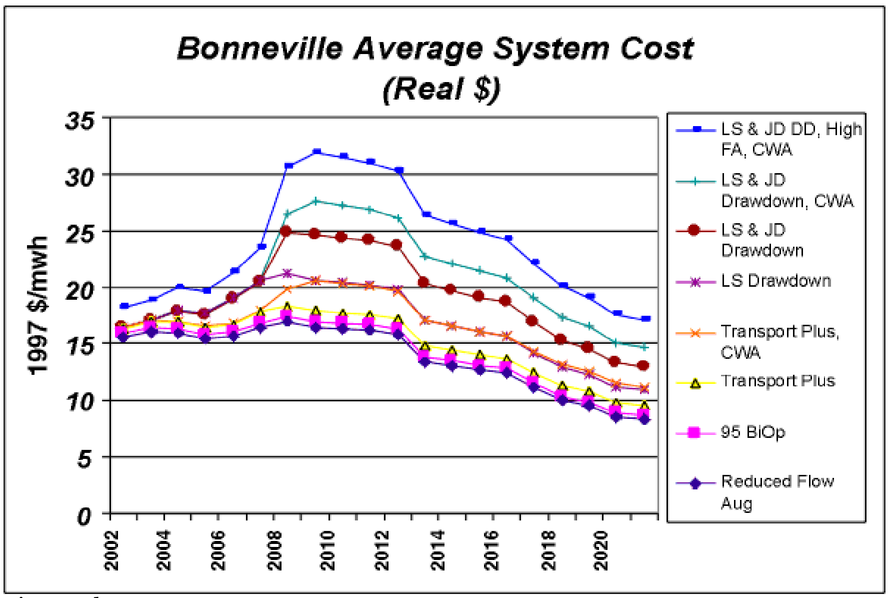


Figure12b

Integrating Analysis

Bonneville's competitive position in the wholesale market was evaluated using an integration model that combines the information described in the preceding sections. The modeling objective is to estimate the potential net revenue for Bonneville under a user-specified salmon mitigation scenario and market price forecast. The model combines a spreadsheet interface for user input, with an underlying simulation model that performs the market revenue and hydro uncertainty calculations.

Principle inputs to the integration model include:

- Bonneville twenty-year base power business line budgets (excluding transmission wheeling);
- Construction cash flows for each capital measure in the salmon mitigation scenario (including transmission replacement in dam removal scenarios), as well as direct program and reimbursable O&M costs;
- Any reductions in the power business line budget for avoided O&M or capital additions no longer required for dams that are taken out of service in a specific salmon mitigation scenario;
- Hydro generation capability for the current federal system and the schedule of changes to capacity and energy capability associated with the salmon recovery scenario. All hydro energy data is specified on a monthly basis for the fifty year (1929-1978) water record;
- Market price scenarios defined through twenty-year time series for monthly on-peak and off-peak Pacific NW market clearing prices;
- Relationships between Pacific NW hydro generation and market prices on a monthly, peak and off-peak basis;
- WNP 2 generation and operating cost stream and the stream of unrecovered decommissioning costs for each potential decommissioning year;
- Energy delivery obligations and estimated revenues associated with existing bulk power contracts, including Bonneville's Canadian

Entitlement return obligation;
- Generation associated with Bonneville's existing renewable and contract purchases;
- An estimate for revenues from sale of ancillary services or other revenues Bonneville is likely to receive which are not reflected in the market clearing price forecasts; and
- An estimate for Bonneville reserves at the end of 2001, and a target level for reserve levels to be held during the study period.

Simulations are run for a twenty-year period, on a monthly basis. To estimate the value of capacity, each month is broken down into on and off-peak periods. Bonneville's hydro generation capability is adjusted through time according to the specified salmon recovery scenario. Sampling from the historical water record captures variation in Northwest hydro generation. Under average water, market prices will equal those input, but the observed market prices in any given time period will vary with NW hydro generation, according to predefined functions derived from the more detailed market analysis.

In estimating potential market value, all of Bonneville's generation is valued at the observed market-clearing price for each time period. Bonneville's monthly hydro generation is shaped into peak and off-peak periods subject to sustained peaking and minimum generation constraints. Generation from WNP-2 and the Bonneville's contract generation is assumed to be flat both seasonally and hourly. Purchase costs for Bonneville's pre-subscription contract obligations and for return of Canadian Entitlement are also priced at the margin.

Bonneville's future costs are estimated by combining the base budget costs, WNP 2 costs, and the non-operational fish and wildlife costs for the salmon recovery scenario (direct program, reimbursable, interest and depreciation, less avoided O&M and capital additions in the drawdown scenarios).

The primary output of the model is the potential net revenue for Bonneville - the value of Bonneville's production at market prices minus Bonneville's costs. As discussed previously, this is not a recommendation that Bonneville sell at market prices, but merely the methodology used to evaluate the competitiveness of Bonneville generation and its value to customers. If Bonneville subscribes the system and sells to customers at cost, the net revenue estimates are the benefits relative to market that will flow through to customers.

Because the model uses the historical water record, evaluation of risks posed by hydro uncertainty under a given scenario can be evaluated. The model can also be used to investigate the effect of using reserves to smooth out a short-term pattern of cost under/over recovery.

The present value of net revenue streams across the study period are calculated for user specified time intervals. This analysis used the two first five-year periods and the entire twenty-year period.

The Results

Summary results for each salmon mitigation scenario, under each of the three market price scenarios are shown in Figures 13, 14, and 15. Results for each scenario are summarized by present values of potential net revenue for three different time periods:

1. The next Bonneville rate period, 2002-2006;
2. The five year period from 2007-2011. Much of the impact from capital expenditures and loss of generation in the recovery scenarios doesn't show up until this second five year period; and
3. The full twenty-year period, 2002-2021.

The values on the charts and in the tables represent mean present values for potential net revenue across fifty water years, using a 7.63 percent nominal discount rate, (5 percent real) with present values taken to 2001.

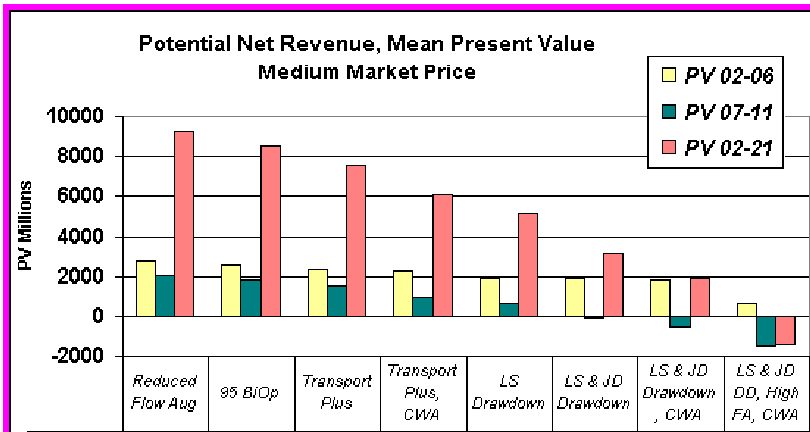
When comparing changes between scenarios, keep in mind that these are estimates of the financial impact to Bonneville only. These values do not reflect any impact associated with changes in non-federal generation, or the effect on any other non-power uses such as transportation, irrigation, recreation or salmon populations.

As shown in Figure 13, under the Medium market price scenario, the system shows positive mean net revenues for the 2002 to 2006 period across all the salmon recovery scenarios, with five year expected present value benefits relative to market ranging from $2.7 billion to $670 million. For the 2007 to 2011 time frame, benefits exist for all but three of the recovery scenarios, ranging from a benefit of $2.2 billion to a loss of $1.2 billion. Across the full twenty-year period all scenarios except one show positive values. The twenty-year present values for all the recovery scenarios range from a benefit of $9.7 billion under the reduced flow augmentation scenario to a loss of $980 million under the scenario incorporating five dam drawdown, increased flow augmentation and the Clean Water Act measures.

Under the High market scenario, all scenarios show positive expected net revenue for all time periods. The twenty year present value benefits range from over $21 billion to about $7.5 billion over the range of scenarios.

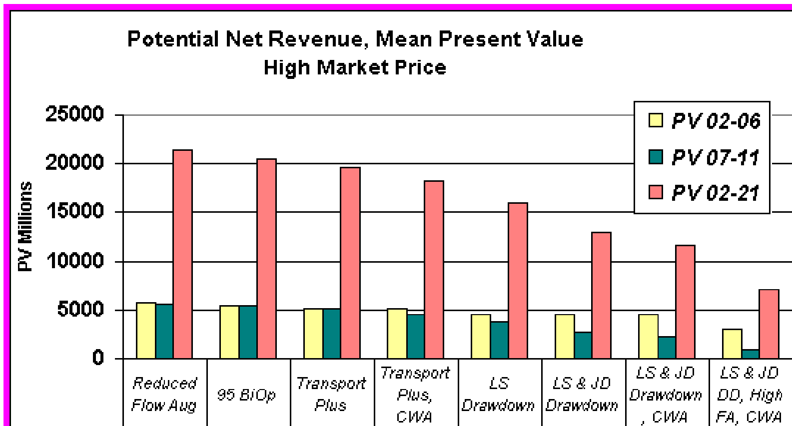
The results for the Low market case are shown in Figure 15. Expectations that future market prices will approximate the Low market case vary widely. For purposes of this report, the Low market case has been described as not very likely but possible. However, there are members of both the technical and policy advisory groups who believe that prices like the Low case have a significant probability of occurring. If market prices resembling the low scenario do occur, Bonneville may have difficulty in remaining competitive. Figure 15 indicates that in the first ten years of the study period, the cost of Bonneville generation is only expected to be below its market value in the two least costly salmon recovery scenarios, Reduced Flow Augmentation and BiOp. All of the other salmon recovery scenarios result in costs averaging above market in the first ten years. For the entire twenty-year period, only the first three scenarios show positive net revenue. The twenty-year average present values range from a benefit of about $2 billion to a loss of over $6 billion dollars.

Comparison of the low and high market scenarios shows the extreme sensitivity of the results to market prices. Using the Transport Plus case as an example, the move from high to low market prices results in a reduction of the twenty-year net present value of almost $20 billion dollars. This equates to a levelized annual difference over the period of about $1.9 billion per year.



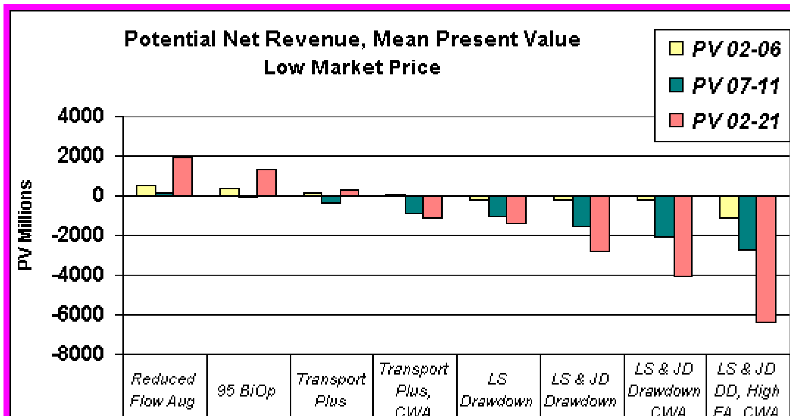
	Reduced Flow Aug	95 BiOp	Transport Plus	Transport Plus, CWA	LS Drawdown	LS & JD Drawdown	LS & JD Drawdown , CWA	LS & JD DD, High FA, CWA
PV 02-06	2769	2552	2313	2273	1870	1890	1854	682
PV 07-11	2068	1832	1537	977	665	-71	-541	-1448
PV 02-21	9286	8531	7583	6115	5162	3160	1927	-1434

Figure 13



	Reduced Flow Aug	95 BiOp	Transport Plus	Transport Plus, CWA	LS Drawdown	LS & JD Drawdown	LS & JD Drawdown , CWA	LS & JD DD, High FA, CWA
PV 02-06	5662	5414	5192	5152	4558	4578	4542	3037
PV 07-11	5611	5377	5102	4542	3789	2701	2232	970
PV 02-21	21347	20519	19637	18169	15916	12888	11655	7045

Figure 14



	Reduced Flow Aug	95 BiOp	Transport Plus	Transport Plus, CWA	LS Drawdown	LS & JD Drawdown	LS & JD Drawdown , CWA	LS & JD DD, High FA, CWA
PV 02-06	537	362	112	72	-216	-196	-232	-1082
PV 07-11	145	-45	-346	-906	-1011	-1573	-2043	-2711
PV 02-21	1901	1306	330	-1138	-1390	-2810	-4043	-6364

Figure 15

The present values in Figures 13-15 result from annual values of mean net revenue for each salmon mitigation/market price scenario. The means are built up from fifty separate simulations of the study period with a different sequence of the historical water record used in each simulation. Results for just one of the individual simulations for the Transport Plus scenario under low market prices are shown in Figure 16. The solid area on this chart represents the net benefit or loss for the federal system production relative to its market value for this single pass through the study period. It shows a system with potential net revenue oscillating around zero in the first ten years, transitioning to positive net revenues approaching $600 million in the last ten years.

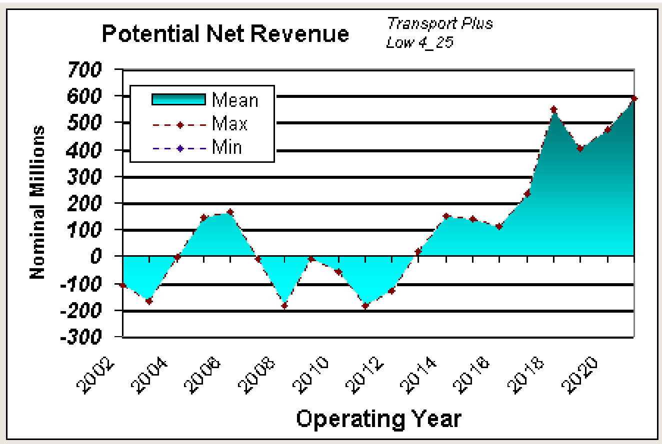


Figure 16

This scenario presents a short-term cash flow problem. One of the mechanisms Bonneville will have for absorbing the shocks of year to year revenue variability is the use of financial reserves. The integration model looks at how reserves can be used to smooth patterns of net revenue volatility. It assumes that revenue shortfalls are made up out of reserves if possible, and that the first use of any surplus revenue is to rebuild reserves if they are short of a specified target level. Figure 17 shows the impact of using reserves in the same Transport Plus / Low Market case. It assumes a beginning reserve level of $500 million in 2002 and a target reserve level also equal to $500 million. The solid area on the chart is net revenue after use of reserves. The solid line is the net revenue without use of reserves and is the same as theshaded area on the previous chart. In a case like this, where the revenue shortfalls are fairly moderate, use of reserves can completely mitigate the cash flow shortfalls in the first half of the study.

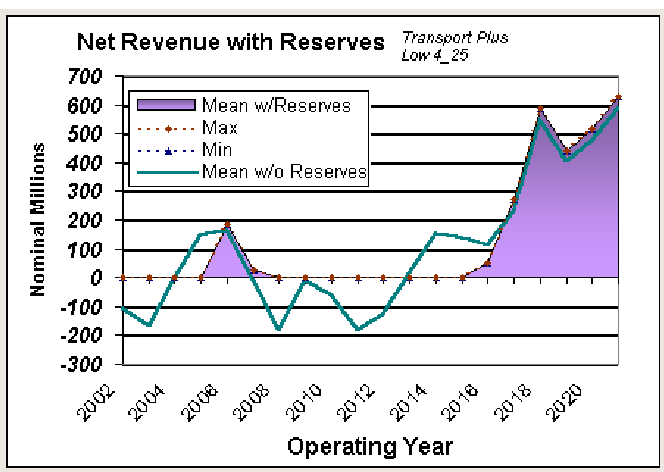


Figure 17

Figures 18 and 19 represent the same scenarios, but show the mean outcomes over the fifty simulations. Figure 18 shows net revenue without use of reserves. It depicts a system with a cash flow problem expected to approach $200 million per year during the first half of the study, transitioning to positive benefits approaching $500 million in the 2020 timeframe. The dotted lines represent the best and worst outcomes in any given year corresponding to the best and worst historical hydro conditions. They show a range of uncertainty due to hydro conditions of about $300 million. In reality you would not see a multi-year succession of best or worst hydro conditions as might be inferred from the figure.

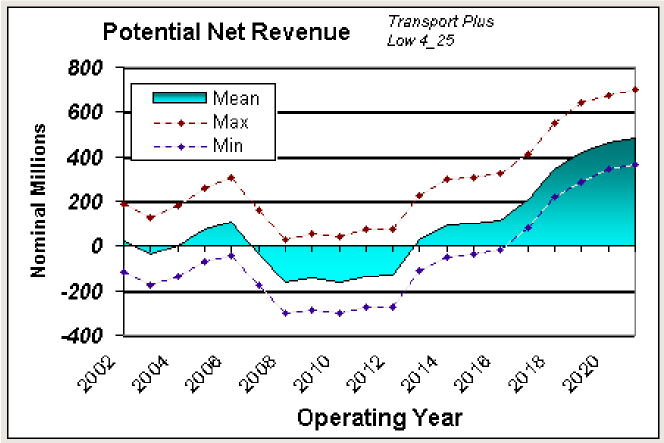


Figure 18 - without reserves

Figure 19 shows the mean effect of reserves in this scenario. The solid line is the mean without use of reserves and again is the same as the area on the previous chart. While not completely eliminating the cash flow problem, the expected shortfall in the first half of the study is reduced substantially. The dashed lines again represent the highest and lowest outcomes in any given year. The highest outcomes are lowered, as this surplus revenue is typically absorbed to replace reserves used in the early years. The worst outcomes are improved in the first several years, but after that are little changed, because in those water sequences, reserves are exhausted early and rebuild infrequently.

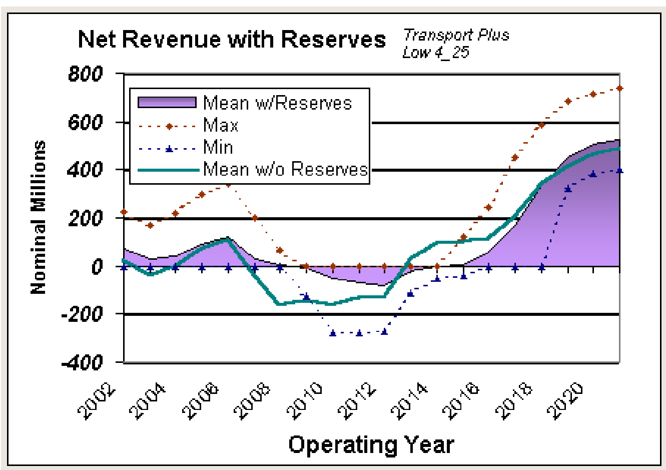


Figure 19

Obviously there is limited range of outcomes where the use of reserves can solve the problem. An initial reserve level of $500 million can be used to offset negative net revenues with a present value of no larger than $500 million. Figure 20 shows the effect of reserves under a Lower Snake and John Day Drawdown / Low Market scenario. Here reserves can reduce the size of the problem for the first several years, but after that are typically exhausted and are of little help.

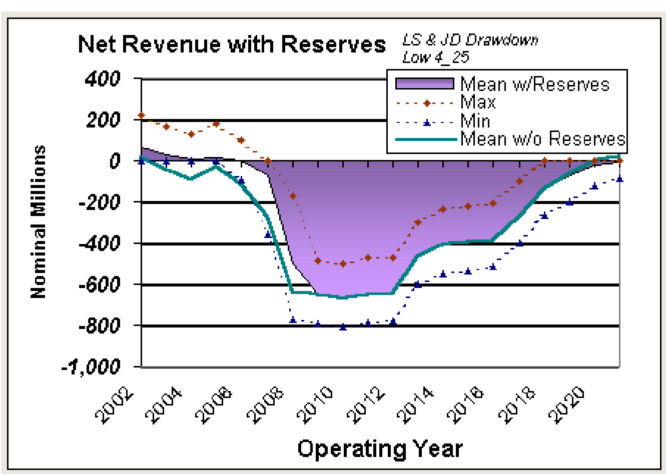


Figure 20

Figure 21 shows the effect of implementation of Cost Review recommendations of about $80 million dollars in the PBL budget, the Transport

Plus/Low market scenario. Cost Review recommendations with respect to WNP2 cost reductions beyond current budget levels are not included here, nor are transmission cost reductions, as they're not part of PBL costs. These cost reductions coupled with the use of reserves completely eliminate potential revenue shortfalls in this scenario.

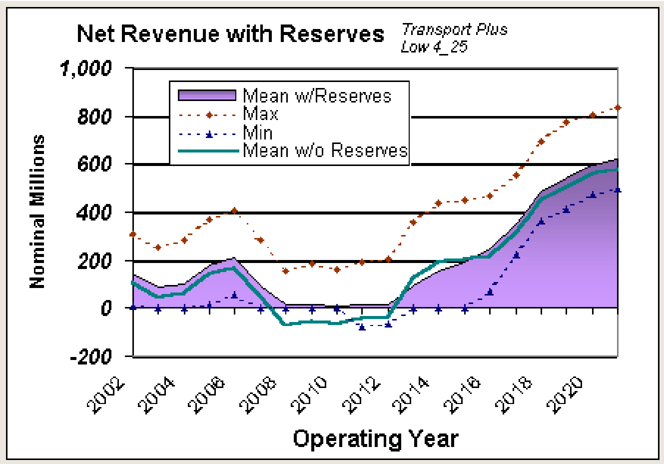


Figure 21 - with Cost Review Recommendations

Finally, the sensitivity of the results to slightly greater market prices was tested. Figure 22 shows the mean net revenues with reserves for the Transport Plus with CWA with the low market scenario while Figure 23 shows the same scenarios with a 10 percent increase in market prices. Relatively small differences in market prices can markedly alter Bonneville's financial situation.

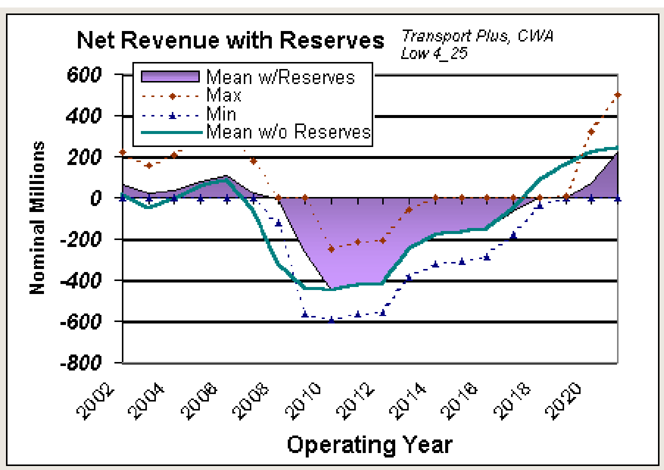


Figure 22

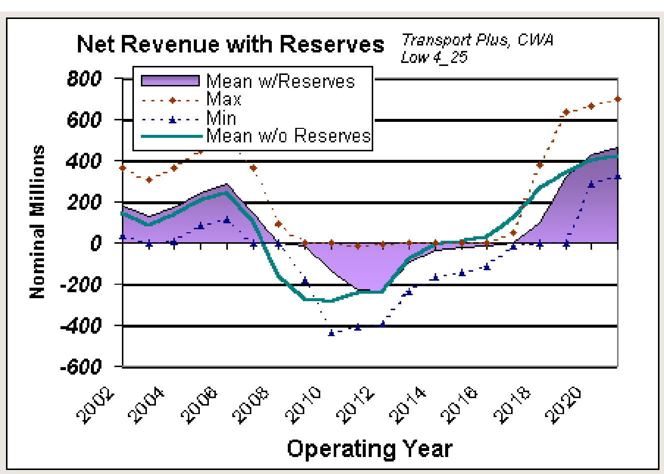


Figure 23 - 10 percent higher market

Conclusions

High Market

The analysis shows that with high market prices, Bonneville demonstrates positive net revenues under all the fish and wildlife scenarios considered. However, even though Bonneville "can afford" the most costly fish and wildlife scenarios doesn't mean those scenarios are without cost to the region. For example, moving from the current BiOp to five dam draw down with Clean Water Act measures means an additional $9 Billion investment in fish and wildlife mitigation. The source of that investment would be higher electricity rates paid largely by Northwest electricity consumers.

Medium Market

With improved market prices corresponding to the medium market scenario, Bonneville demonstrates positive net revenues for the study period in all but the most costly of the scenarios evaluated. It also demonstrates positive cash flows in each of the sub-periods for all but the scenarios involving five dam drawdowns. For these mitigation alternatives, negative net revenues are experienced in the 2007-2011 period. Again, however, Bonneville would appear to be able to afford most of the fish and wildlife mitigation scenarios. However, they would require additional billions in investment in fish and wildlife mitigation by regional electricity consumers.

Low Market

In contrast, low market conditions present Bonneville with significant financial challenges. With low market prices, Bonneville experiences periods of negative net revenues under any fish and wildlife scenario involving additional costs or degradation of power production capability. The most critical period is typically the 2007-2011 period when the higher fish and wildlife costs and/or generation losses occur and before Bonneville's debt service on the Washington Public Power Supply System bonds begins to decline.

If Bonneville is able to enter the study period with substantial reserves ($500 million was assumed in this study), the periods of negative net revenues can be mitigated in the more moderate cost fish and wildlife scenarios. However, in the cases with the high capital costs associated with Clean Water Act implementation and/or with the loss of generation associated with drawdowns, the reserves have only a temporary effect. They are quickly exhausted and cannot be rebuilt for several years,

With low market conditions, Bonneville's financial situation is very much "on the cusp." Relatively small differences in costs or market prices make significant differences in the outcomes. For example, successful implementation of further cost reductions, such as the additional $80 million in Cost Review recommendations, could, in some circumstances, mean the difference between experiencing negative net revenues and not. Also, in several instances, market prices as little as 10 percent higher than the low price scenario mean the difference between negative and positive net revenues.

Summary

Under a wide range of conditions, Bonneville demonstrates significant value to customers even if called upon to bear relatively large additional fish and wildlife mitigation costs. Only under combinations of persistent low market conditions and increased fish and wildlife costs and/or operational impacts does Bonneville experience significant negative net revenues for extended periods. Those results are extremely sensitive to small changes in Bonneville's costs or market prices. This underscores the importance of Bonneville's cost management efforts.

Financial risk management mechanisms like reserves can mitigate the negative net revenues in some conditions. In other conditions, however, the mitigating effect of the assumed reserves and/or further cost reductions is insufficient. In these cases, Bonneville would need larger reserves; some sort of contingent cost recovery mechanism or may have to look to other of funding. It is also possible that the schedules for implementation of the various fish and wildlife mitigation scenarios used in this analysis will not be met. The biological and economic effects of changes in the schedule for implementation of fish and wildlife measures should be evaluated.

Appendix A - Oversight Groups

Policy Oversight Group	Technical Work Group
Bill Drummond, Montana Generating and Transmission Cooperative **Angus Duncan,** Columbia Policy Institute **Don Kopczynski,** Washington Water Power **Rob Lothrop,** Columbia River Intertribal Fish Commission **Steve Oliver,** Bonneville Power Administration **John Saven,** Northwest Requirements Utilities **Ed Sheets,** Consultant, National Marine Fisheries Service **Steve Waddington,** Direct Service Industries **John Etchart,** Council member, Montana **Mike Kreidler**, Council member, Washington **Todd Maddock,** Council member, Idaho	**Ray Blivin,** Consultant, Direct Service Industries **Alan Hicks,** Public Power Council **Bryan Crawford,** Bonneville Power Administration **Marty Howard,** Consultant, Columbia River Intertribal Fish Commission **Jim Litchfield,** Consultant, Investor-Owned Utilities **Audrey Perino,** Bonneville Power Administration **Phil Sher,** Pacific Northwest Generating Company **Phil Thor,** Bonneville Power Administration **Steve Weiss,** Northwest Energy Coalition **Warren Winter,** EPIS Inc.

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