Fifth Power Plan Summary and Action Plan

KEY CONCLUSIONS

The region should increase its efforts to secure cost-effective conservation, beginning immediately. It is the least expensive and has the least adverse environmental impacts of any available resources. Development of this conservation will reduce the likelihood of another electricity crisis like the one the West experienced in 2000 and 2001.

In addition, demand response resources -- agreements between utilities and customers to reduce demand for power during periods of high prices and short supply -- should be put in place over the next few years so they can be implemented quickly if needed.

The region should be ready to add new generating resources after 2010, mostly wind generation as well as a coal-fired power plant. Later in the period some additional gas-fired generation could be needed. To facilitate that development, an inventory of permitted sites, including projects for which construction has been suspended, should be maintained, and needed transmission upgrades should be identified so that these resources can be constructed and brought on line quickly when needed. If major transmission upgrades are needed, their construction will have to be initiated in advance of construction of the power plants.

Modest levels of wind power development should be undertaken at a geographically diverse set of promising wind resource areas over the next five years to resolve uncertainties associated with this resource and to prepare for its eventual large-scale development. Wind projects currently being considered by regional utilities and state system benefits charge administrators could fulfill this goal. Finally, efforts to identify and develop cost-effective lost-opportunity generating resources, including combined heat and power (cogeneration) and biomass applications, should be reinforced.

There are individual utilities in the region that have immediate resource needs beyond that which can be met through conservation. However, from an aggregate regional standpoint, this plan does not call for substantial amounts of new generating capacity before the end of the present decade unless conservation goals are not met, significant amounts of generation are retired or otherwise become unavailable, or the region experiences sustained high rates of growth in demand for electricity. This is because there is a significant surplus of generating capability in the region due to reduced demand and construction of new generating plants over the past three years. Most of the surplus generation is owned by independent power producers (IPPs). The IPPs do not now have long-term contracts with regional utilities nor do they have firm transmission access to markets outside the region. However, as will be discussed later, there are reasons why regional utilities with near-term resource needs may not to contract long-term for power with the IPPs or purchase the IPP facilities.

BACKGROUND

The Northwest Power and Conservation Council is required to develop a 20-year power plan under the Pacific Northwest Electric Power Planning and Conservation Act to assure the region an adequate, efficient, economic, and reliable power system. To accomplish this, the plan addresses the uncertain future we face; identifies realistic resource alternatives; analyzes the costs and risks that arise from the interaction of resource choices and uncertain futures; and lays out a flexible strategy for managing those costs and risks.

Like the Council's first power plan, released in 1983, this plan comes on the heels of a major crisis in the region's power system. The Council's first plan was developed in the aftermath of the effort to plan and build several large nuclear and coal-fired power plants and the failure to anticipate the nearly disastrous effect the costs of those plants would have on consumer rates, the region's economy, and electricity demand.

This plan has been developed in the aftermath of the Western electricity crisis of 2000-2001. The causes of this crisis were very different. They included the failure to develop adequate resources; the failure to anticipate the price volatility short supplies might spur; the failure to put in place effective market rules and mechanisms; and the actions of some who took advantage of the market's vulnerability. The net effect, however, was much the same. Retail rates in the region soared and demand plummeted. The impact on the region's economy for the years 2000 though 2002 was at least $2.5 billion and as much as $6 billion in increased power purchase costs and foregone economic activity. These impacts linger today.

Both these events and their consequences should serve as clear reminders that we cannot know what will happen in the future, and that uncertainty breeds risk. It would not have been possible for planners to predict these events with certainty. However, it should have been possible to anticipate that similar events could happen; to test plans against those possibilities; to assess the risks; and to modify plans if the risks were too great.

The Council's plans have always been about assessing risk and planning to manage risk. The year-to-year uncertainty about hydroelectric generation, uncertainty about future demand for electricity, and uncertainty about fuel prices have always been considered in the Council's plans. When the Council's early plans were written, generating resources tended to be large, to have long planning and construction lead times, and to be very capital-intensive. The risk that investors would not be able to recover their costs if demand was lower than expected was significant.

Planning today must cope with these, and other, uncertainties. Gas-fired generation, which has relatively low capital costs and a short lead time to build has reduced capital risk, but it is more vulnerable to fuel cost risk as gas prices have become more uncertain. Possible climate change mitigation policies could pose a significant risk for generating technologies using carbon-intensive fuels; but whether such policies will be implemented, and if so, what the magnitude and timing of any carbon emissions penalties will be, is very uncertain. Some renewable energy technologies like wind, though capital intensive, have short lead times and provide a hedge against fuel price and climate change risk. But it is not known whether their current trends of falling cost will continue, or whether integration of intermittent generation into the power system will prove significantly more costly as the penetration of these technologies increases. And there is electricity market price risk. It is tempting to think that electricity markets will be orderly and predictable in the future. To assume that, however, could expose the region to significant risk.

Moreover, many of these uncertainties are interdependent. Volatility in gas prices and hydroelectric generation can, for example, translate into volatility in electricity markets.

The Northwest is part of a complex, highly interconnected power system linking the region and the entire West Coast. As a consequence, the region is always subject, to some degree, to the effects of the actions of others. The power system has many different kinds of participants; a mix of regulated and competitive elements, and fragmented rules, regulations, responsibilities, and authorities. Attempting to isolate the region from the rest of this system would be difficult and very costly; but inherent in the status quo is significant uncertainty and risk that must be recognized and managed.

PLANNING FOR AN UNCERTAIN FUTURE

Planning for an uncertain future requires assessing risk. This requires that we characterize the key uncertainties the power system faces. Can we, through experience, analysis, and informed judgment, develop reasonable characterizations of future uncertainty that will help illuminate resource choices for the region? The Council believes the answer is yes.

To evaluate the performance of possible plans, the different possible paths that the key sources of uncertainty might take over the planning period are combined into "futures." The Council tests its plans against approximately 800 futures in what is referred to as a portfolio analysis. Key uncertainties include:

Hydroelectric Generation

The potential variation in the output of the regional hydroelectric system is very large and, therefore, poses an important uncertainty. But we have 50 years of hydrologic data with which to characterize the year-to-year uncertainty in hydroelectric generation with a high degree of confidence. There is further uncertainty resulting from potential shifts in temperatures and precipitation patterns associated with climate change. While we have made an assessment of the possible effects of climate change, this uncertainty has not been included in the analysis.

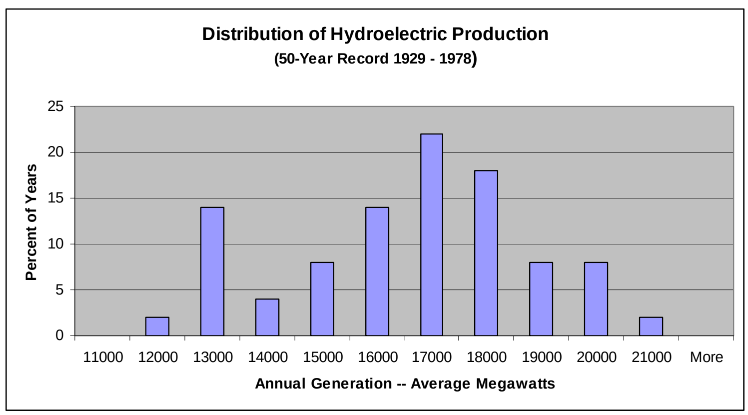


Figure ES-1

Demand

Demand for electricity is a key uncertainty. Rapid demand growth means additional resources will be required. Conversely, a downturn in load growth means fewer resources and the potential for some resources to go underutilized. The Council forecasts potential growth in demand with a range of forecasts. These forecasts are based on analysis of the economic, demographic, and technological factors driving demand for electricity. Rates of growth between the medium-high and medium-low forecasts are judged to be equally likely while rates of growth corresponding to the high and low forecasts have a very low probability. However, overall trends are only part of the story. We have seen that we can experience extended periods of more rapid growth or, conversely, periods of load loss and depressed growth. If rapid demand growth outstrips supply, prices can rise and reliability can be at risk. If demand slows or drops, prices may be depressed and some expensive resources may be unable to fully recover their costs. To assess risk it is necessary to reflect the variation in demand that can occur. The forecast range of annual loads and a same of futures for quarterly average loads are shown in Figure ES-2. The dates are expressed in "hydro years" which begin in September 1 of the preceding calendar year.

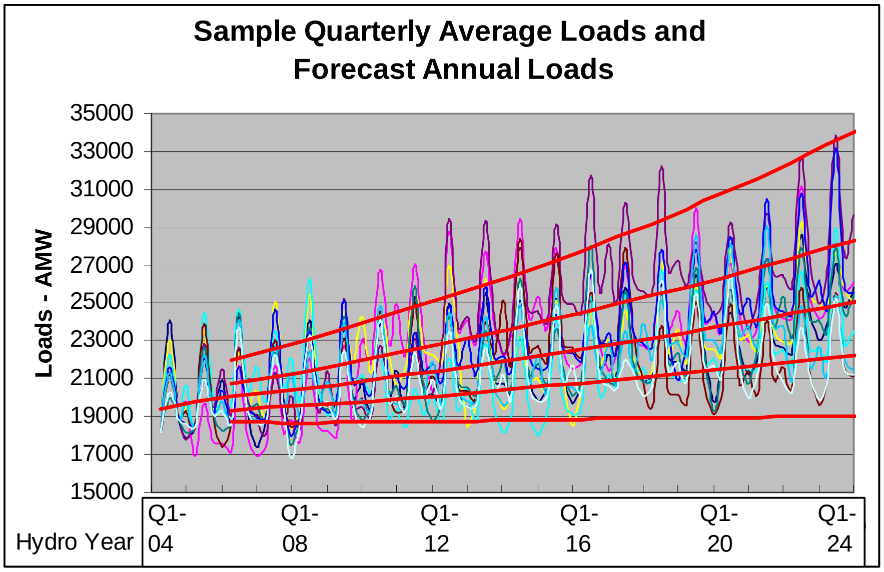


Figure ES-2

Fuel Price

Similarly, fuel price uncertainty is an important source of risk. In particular, periods of high fuel prices can increase operating costs for those resources dependent on that fuel. The Council forecasts a range of natural gas, oil, and coal prices. Currently, the most important is natural gas because of the relative attractiveness of natural gas fueled combined cycle combustion turbines. Gas-fired generation now makes up approximately 22 percent of the electricity generation in the region under average water conditions. Under the right conditions it could contribute more. As with demand, the Council prepares a range of gas price forecasts based on analysis of the outlook for supply and demand. But we also know that the price of natural gas exhibits short-term volatility and longer term variation. Periods of oversupply can, as we have seen in the recent past, depress prices for extended periods.

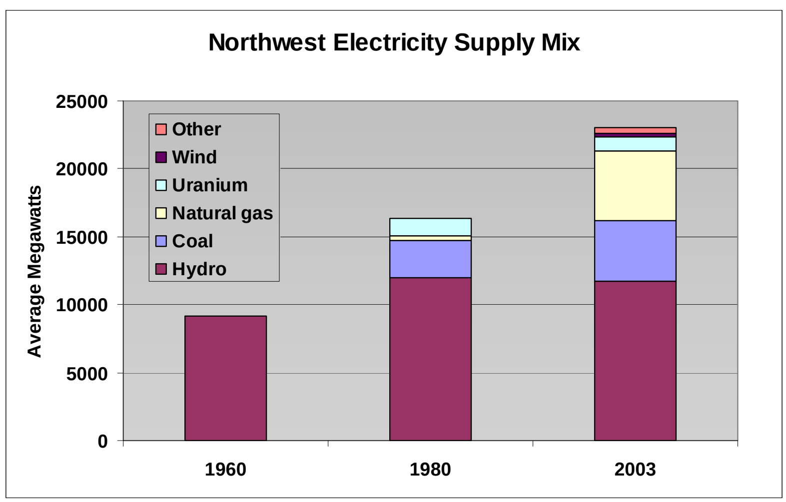


Figure ES-3

Conversely, periods when supplies are tight can result in extended periods of relatively high prices, as we are experiencing now, until new supplies can be developed. These periods of price and supply variation can have a significant effect on the costs and risks associated with gas-fired

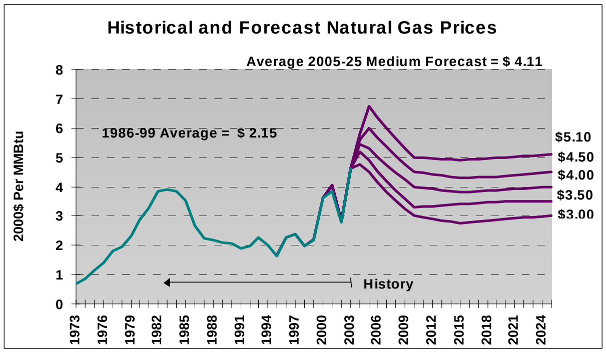


Figure ES-4

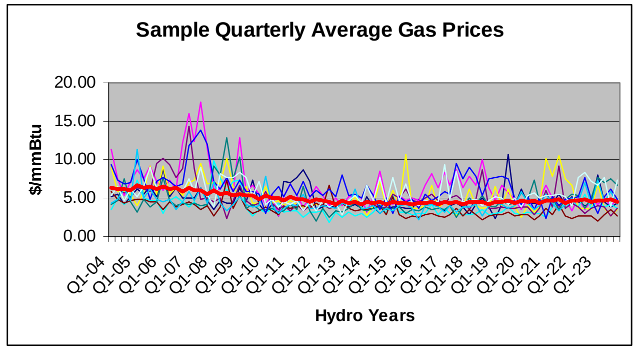


Figure ES-5

generation. Both the forecast range and a sample of gas price futures used in the analysis are shown in figures ES-4 and ES-5.

Environmental Regulation

Future environmental regulation, particularly the potential for regulation of carbon dioxide emissions, is an important uncertainty. If we knew with certainty that there would never be a carbon tax or the equivalent, coal-fired generation could be an economically attractive option. Conversely, if we knew with certainty that a large carbon penalty would be imposed, coal-fired generation would not be considered, absent a reduction in the cost of carbon sequestration. At present, future carbon dioxide control costs are highly uncertain. The small carbon dioxide offsets required of new resources in Oregon and Washington are likely to set a lower limit on carbon dioxide costs in the Northwest. Published estimates of the costs of carbon dioxide offsets required to lower overall carbon dioxide production to 1990 levels may be at an upper limit for the next decade or two. We have treated this issue probabilistically. The probability of a carbon penalty of some level increases over the planning period. It is 0 prior to 2008, increasing to 67 percent by the end of the planning period. Beginning in 2008 the carbon penalty can be between 0 and $15 per ton beginning in 2008, and between 0 and $30 per ton beginning in 2016.

Electricity Market Price

The market price of electricity is an important uncertainty and source of risk. The market fulfills a balancing function. If a load serving entity is short of resources to meet its loads, it hopes to be able to buy from the market at a reasonable price to meet its needs. If a generation owner has excess generation, it hopes to sell into that market at a price sufficient to cover its operating costs and recover a portion of its capital investment. That market is not limited to the Northwest, but comprises the entire interconnected Western system up to the limits of transmission capacity. To a large extent, the electricity market price is a function of demand, the amount and characteristics of supply, and fuel prices. But as the experience of 2000 and 2001, circumstances can arise that drive prices well beyond the operating cost of the most expensive plants that have to operate. Those events and the volatility they cause can be an important source of risk.

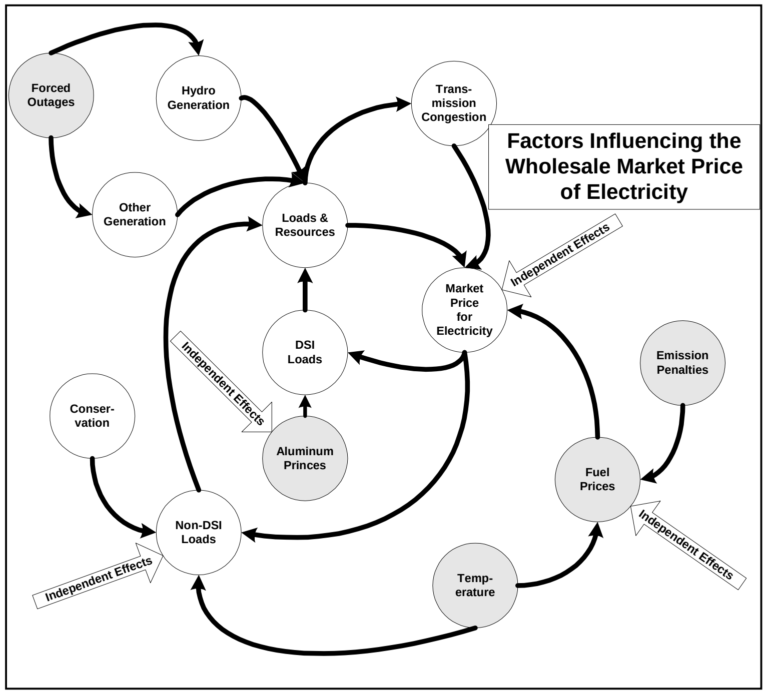


Figure ES-6

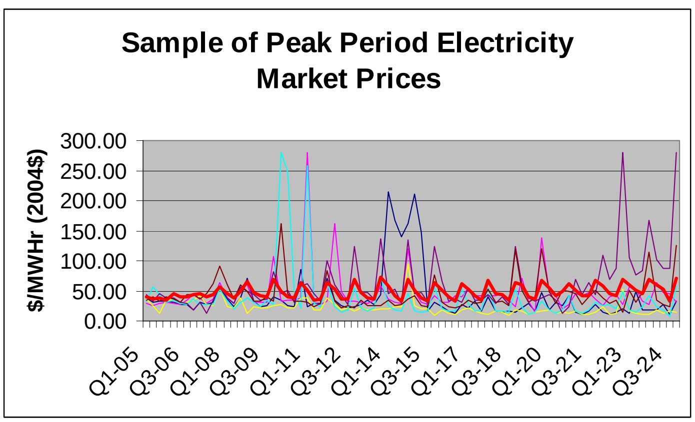


Figure ES-7

The Role of Independent Power Producers

This is the first time in the Council's planning history that independent power producers (IPPs) account for a significant amount of the generation in the region. There are approximately 3,000 average megawatts of IPP generation in the region that is not owned by, or under long-term contract to, regional load serving entities. Most of these plants are new, gas-fired combined cycle combustion turbines, but there are also about 1,100 average megawatts from an existing coal-fired plant. This IPP generation does not have firm transmission access to markets outside the region and is available to meet regional needs. This generation poses a different kind of uncertainty for planning.

The power from these plants is currently sold into the market when prices are sufficient to cover operating costs and contribute to covering capital costs. While the presence of these plants in the region helps moderate market prices, it does not eliminate the risk of high market prices for regional consumers.

There are a number of individual utilities within the region that have near-term resource needs. They can satisfy those needs in several ways. Assuming they are not constrained by transmission limitations, they can choose to purchase on the market until the surplus erodes. They can choose to enter into long-term contracts with IPPs or purchase an ownership interest in all or part of an IPP facility. Or, they can choose to build additional generation themselves. In the first instance, the utility is exposed to market price risks. In the latter instance, the utility reduces exposure to market risk (unless they contract at a market linked price) but incurs increased fixed costs and the risks those entail. It is possible and even likely that different decisionmakers will make that tradeoff differently.

For this plan, we have assumed that the uncommitted IPP generation continues to sell in the market when it is able to do so. This should not be interpreted as a prediction or a preference. Clearly, there is significant value in the IPP resources, and they have the advantage of no construction lead-time. The analysis indicates that value is on the order of almost $5 billion. But a significant investment will have to be made by regional utilities to secure that value. What happens to the IPP generation has implications for resource development. If the region secures the IPP generation, other resource development could be deferred. Some IPP generation has already been purchased or contracted for long-term use by regional utilities and more may be acquired. However, the analysis in this plan cannot possibly capture the complexities of the financial and market risk profile of each individual utility and IPP in the region; all the considerations in utilities' build versus buy decisions; or the negotiations between utilities and IPPs. The assumption that the uncommitted IPP generation sells into the market provides a reasonable starting place for the analysis.

RESOURCES FOR THE FUTURE

The performance of a plan depends very much on how the characteristics of the different resources interact with different possible futures. These characteristics include factors such as capital cost, efficiency, operating cost, lead time for construction, fuel type, and so on. The Council's plan is based on detailed analysis of the important characteristics of key resource alternatives. These include both generating resources and "demand side" resources like conservation and demand response. Conservation is the more efficient use of electricity and is the highest priority resource under the Northwest Power Act. Demand response is temporary reductions or shifts in the timing of some uses of electricity. This resource has not been considered in earlier plans but proved itself to be very beneficial during the 2000-2001 electricity crisis.

The primary resources considered in the portfolio analysis and their relative characteristics are summarized in Table ES-1. Some of the important considerations are the unit size, capital and operating costs, emissions characteristics and construction lead-time. Typically, with smaller unit sizes and shorter lead times comes greater ability to adapt to changing circumstances. Capital costs are important in that once incurred, they cannot be avoided.

Table ES-1 – Resource Characteristics

Resource	**Typical Project Size**	**Construc-tion Lead Time**	**Capital Cost**	**Fuel and other operating costs**	**Carbon Dioxide Production**	**Dispatch-ability**
Conservation	Very small	Short	Moderate to high	None	None	None
Demand Response[1]	Very small to small	Short, once resource confirmed	Low	High with some exceptions	None	High
Gas-Fired Combined Cycle Combustion Turbines	250 - 600 MW	2 Years	Moderate, slowly declining	Moderate but potentially volatile	Moderate	Moderate-high
Gas-Fired Single Cycle Combustion Turbines	100 MW	1 Year	Moderate, slowly declining.	High but potentially volatile	Moderate to high	High
Coal-Fired Steam Generation	250 - 500 MW	3 – 4 Years	High, stable	Low	High	Moderate
Wind Turbines	30- 300 MW (per project)	1 year if adequate trans-mission available	High but declining	None	None	None, intermittent

There are other resources that have been considered in developing this plan. Many, such as combined heat and power (also known as cogeneration); power plants using bio-residue fuels; and other "distributed generation" technologies are very site-specific. Their cost-effectiveness frequently depends on a number of factors such as: the ability to offset other fuel use; localized benefits for reliability or power quality; the ability to offset transmission or distribution system investment or reduce losses; the availability of particular fuels; and whether construction can be accomplished as part of a larger plant or building renovation. These are frequently potential "lost-opportunity" resources, i.e., their cost-effectiveness may depend on the timing of other actions such as transmission upgrades, environmental requirements, plant renovation, and so on. Efforts should be made to identify cost-effective projects and develop them when the opportunity arises.

There are other resources that have not been included in the portfolio analysis and resource development recommendations because of significant impediments to their development. Because of this, they are difficult at present to consider "available" as defined by the Northwest Power Act. These include: coal gasification, potentially with carbon sequestration; solar photovoltaics; advanced nuclear power plants; and Alberta oil sands cogeneration. Because of the potential attractiveness of these resources under plausible future conditions, it is important to understand their potential role; identify the key impediments to their development; and determine what regional actions could help resolve these impediments. They may figure prominently when this plan is revised later in this decade.

1 Demand response is the ability to take load off the system or shift it to lower demand periods during periods of very high prices and short supplies.

The resources considered in the development of this plan are summarized in the "supply curve" shown in Figure ES-8. This shows the estimated levelized cost of specific resources in cents per kilowatt-hour and the estimated cumulative supply in average megawatts available over the planning period. Also shown is an estimate of the uncertainty band around the estimated costs. For example, gas-fired generation is subject to a range of possible fuel costs and carbon emissions penalties that will affect the cost of the power produced. The cost of power from wind generation is subject to uncertainty regarding cost improvements over time, integration costs, resource quality, financing, and transmission costs.

How can resources be compared on an "Apples to Apples" basis?

Not all resources are alike. Some resources, like conservation, have costs that are entirely or almost entirely capital. These costs are incurred when the conservation is installed but the benefits continue for the life of the measure, 30 or more years in many instances. In contrast, other resources, like a gas turbine, have some capital costs incurred at the front end but also ongoing fuel and operating costs over the life of the project. To compare these resources on the basis of their first year costs would be very misleading. To compare such resources fairly, we calculate the "levelized cost" of each resource. This involves calculating all the costs – capital, fuel, and operating – over the planning period, including replacements if required. These future costs are discounted to their present value in fixed year, inflation-adjusted dollars. Their present value total costs are converted into a fixed annual payment like a mortgage payment. This payment divided by the annual electricity production or savings yields the levelized cost per kilowatt-hour.

This should not, however, be interpreted as the order for acquisition. That can only be determined by evaluating resources in the context of the operation of the entire system including other resource additions and the uncertainties of a large number of possible futures.

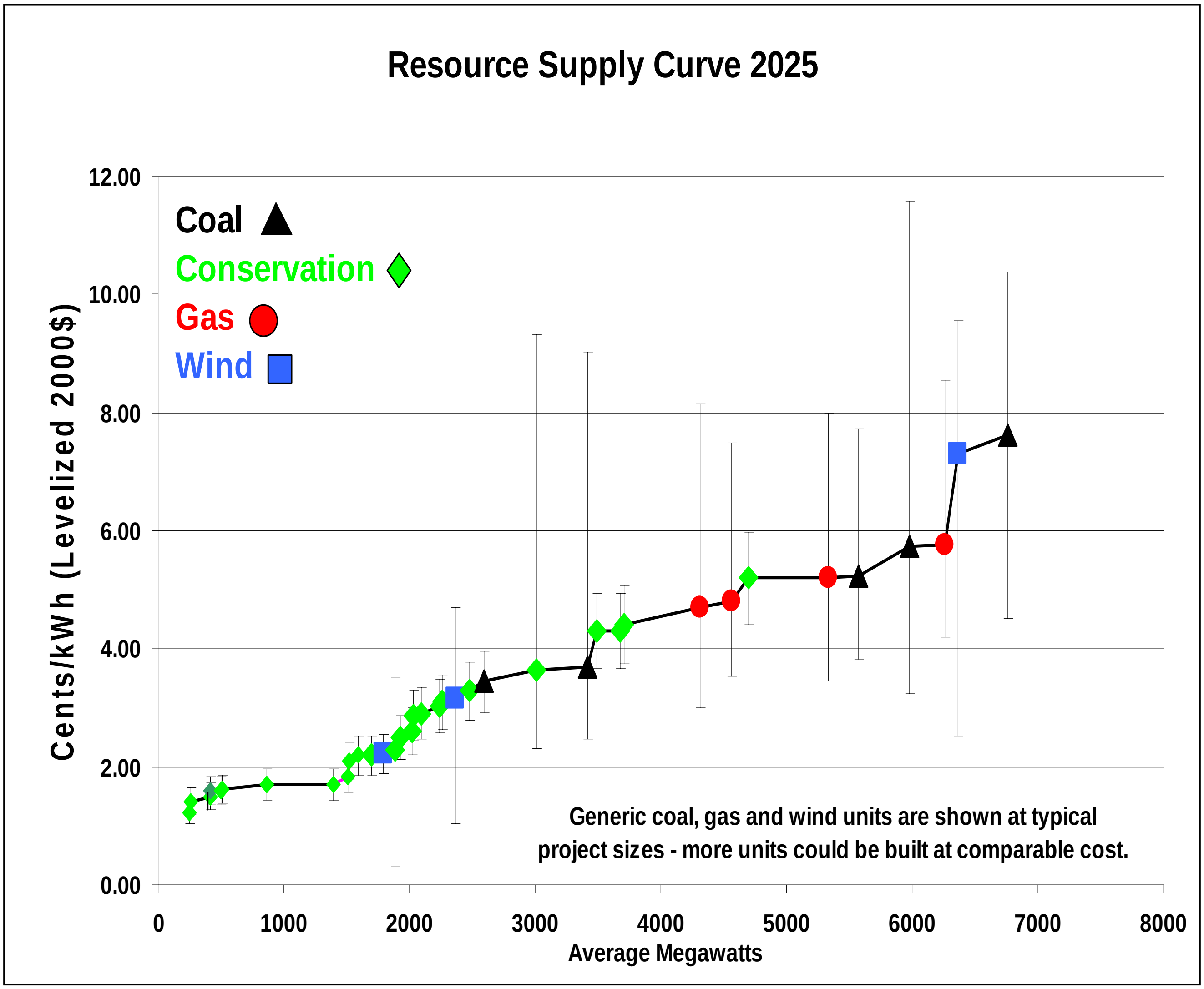

Resource Supply Curve 2025
Coal
Conservation
Gas
Wind
Cents/kWh (Levelized 2000$)
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0
1000
2000
3000
4000
5000
6000
7000
8000
Average Megawatts
Generic coal, gas and wind units are shown at typical project sizes - more units could be built at comparable cost.

Figure ES-8

Table ES-2 Resource Supply Curve

		Average Cost (Cents/kWh) (Levelized 2000$)[10]			Cost-Effective Potential	Cumulative Potential
	Sector and End-Use	**Low**	**Avg**	**High**	**(MWa in 2025)**	**(MWa in 2025)**
1	Commercial New & Replacement Lighting[2]	1.04	1.22	1.41	245	245
2	Commercial New & Replacement Infrastructure[2,8]	1.21	1.42	1.63	11	256
3	New & Replacement AC/DC Power Converters[2]	1.27	1.49	1.71	156	412
4	Residential Dishwashers[2]	1.36	1.60	1.84	10	422
5	Agriculture – Irrigation[2]	1.36	1.60	1.84	80	502
6	Commercial New & Replacement Shell[2]	1.37	1.62	1.86	13	514
7	Industrial Non-Aluminum[2]	1.45	1.70	1.96	350	864
8	Residential Compact Fluorescent Lights[2]	1.45	1.70	1.96	535	1399
9	Commercial Retrofit Lighting[2]	1.56	1.84	2.11	114	1513
10	Residential Refrigerators[2]	1.79	2.10	2.42	5	1518
11	Residential Water Heaters[2]	1.87	2.20	2.53	80	1598
12	Commercial Retrofit Infrastructure[2,8]	1.87	2.20	2.53	105	1703
13	Commercial New & Replacement Equipment[2,9]	1.89	2.22	2.56	84	1787
14	Central MT Wind for local load, firmed and shaped[1]	0.31	2.29	3.51	100	1887
15	Residential New Space Conditioning – Shell[2]	2.13	2.50	2.88	40	1927
16	Residential Existing Space Conditioning – Shell[2]	2.21	2.60	2.99	95	2022
17	Commercial Retrofit Shell[2]	2.44	2.87	3.30	9	2031
18	Residential HVAC System Efficiency Upgrades[2]	2.47	2.90	3.34	65	2096
19	Commercial New & Replacement HVAC[2]	2.57	3.03	3.48	148	2244
20	Residential HVAC System Commissioning[2]	2.64	3.10	3.57	20	2264
21	Eastern WA/OR Wind[1]	1.04	3.16	4.69	100	2364
22	Commercial Retrofit HVAC[2]	2.80	3.29	3.78	117	2480
23	Commercial Retrofit Equipment[2,9]	2.93	3.45	3.97	109	2589
24	Eastern WA/OR IGCC w/o carbon dioxide Separation[1,4]	2.32	3.64	9.33	425	3014
25	Eastern WA/OR Pulverized Coal (or MT Coal w/ TX to MidC at embedded-cost) [1,5,11]	2.48	3.69	9.02	400	3414
26	Residential HVAC System Conversions[2]	3.66	4.30	4.95	70	3484
27	Residential Heat Pump Water Heaters[2]	3.66	4.30	4.95	195	3679
28	Residential Hot Water Heat Recovery[2]	3.74	4.40	5.06	25	3704
29	Eastern WA/OR CCCT[1,3]	3.01	4.71	8.15	1000	4314
30	Goldendale CCCT[3]	3.54	4.80	7.50	248	4562
31	Residential Clothes Washers[2]	4.42	5.20	5.98	135	4697
32	Grays Harbor CCCT[3]	3.46	5.20	8	640	5337
33	Montana First Megawatts IGCC[2,4]	3.83	5.24	7.73	240	5577
34	MT Coal Steam w/ TX to MidC at cost of expansion [1]	3.25	5.74	11.58	400	5977
35	Mint Farm CCCT[3]	4.19	5.75	8.54	286	6263
36	Central MT Wind w/ TX to MidC, firmed and shaped[1]	2.53	7.3	9.57	100	6363
37	MT IGCC w/ TX to MidC and carbon dioxide separation[1,4]	4.52	7.63	10.37	401	6764

Footnotes to Table ES-2:

1) These units do not represent the entire potential of the resource. They are typical size generation installations and could be duplicated.
2) The uncertainty interval shown for all conservation resources is +/- 15 percent.
3) The uncertainty interval for generic combined cycle combustion turbine generators is defined on the low side by a 57 percent capacity factor, medium-low natural gas prices, no carbon dioxide control, a 10 percent "learning factor" for technology and public utility financing costs. The high side of the uncertainty interval is defined by a 48 percent capacity factor, high natural gas prices, carbon dioxide control costs based on the proposed Climate Stewardship Act (CSA), no learning factor and independent power producer financing costs. The uncertainty intervals for the Goldendale, Grays Harbor, and Mint Farm CCCTs used the same assumptions except the generating technology was assumed fixed at 2001 levels.
4) The uncertainty interval for gasified coal generators (IGCC) is defined on the low side by medium low coal prices, no carbon dioxide control, low construction cost, 36-month construction period, 10 percent learning factor, and all public utility financing costs. The high side of the interval is defined by medium coal prices, carbon dioxide control costs based on the CSA, high construction cost, 48-month construction period, no learning factor, and all independent power producer financing costs.
5) The uncertainty interval for pulverized coal generators uses the same assumptions as gasified coal generators, with the exception that the low cost assumption for learning factor is 5 percent instead of 10 percent.
6) The uncertainty interval for Eastern WA/OR wind is defined on the low side by 32 percent capacity factor, a 15 percent learning factor, green tag value of $6/MWh, $4/MWh for shaping and firming, all public utility financing costs, and the production tax credit for wind continuing indefinitely at $1.50/MWh. The high side of the interval is defined by a 28 percent capacity factor, a 5 percent learning factor, green tag value of $6/MWh, $8/MWh for shaping and firming, all independent power producer financing costs, and no production tax credit after 2005.
7) The uncertainty interval for central MT wind uses the same assumptions as Eastern WA/OR, except that the assumed capacity factor is 38 percent for the low side, and the capacity factor is 34 percent on the high side.
8) Commercial infrastructure includes sewage treatment, municipal water supply, LED traffic lights, and LED exit signs.
9) Commercial equipment includes refrigeration equipment and controls, computer and office equipment controls and laboratory fume hoods.
10) Levelized cost estimates in this table are not exactly comparable. Levelized cost estimates for generating resources in this table do not include distribution system costs needed to deliver power to customers. These costs are avoided by conservation, but are very location-specific and are not credited in these figures.
11) There may be enough existing transmission capacity to move 400 MW of output from MT to MidC at embedded cost.

EVALUATING PLANS

In evaluating plans, the Council relies on both analytical models and informed judgment. Computer models are used to screen a large number of alternative plans. For each plan, the models calculate the cost of operation and expansion of the power system over hundreds of different futures. Figure ES-9 illustrates the distribution of those costs over a number of futures. Two primary measures of a plan's performance are used: the average total system cost over all the futures; and a measure of risk – the average of the cost of the worst 10 percent of the outcomes. Other risk measures, such as the standard deviation of the distribution of costs are also considered, as are measures of the average period-to-period cost variation and maximum cost variation across the study period. These measures are intended to give insights into the potential for retail price volatility. In addition, measures of resource adequacy are also evaluated. The objective is to find plans that are "robust," that is, plans that perform well over a wide range of possible futures. But this is only the start. The plans are "stress tested" to evaluate sensitivity to different assumptions. This process of testing, changing assumptions, and re-testing continues until the Council is satisfied that a plan makes sense.

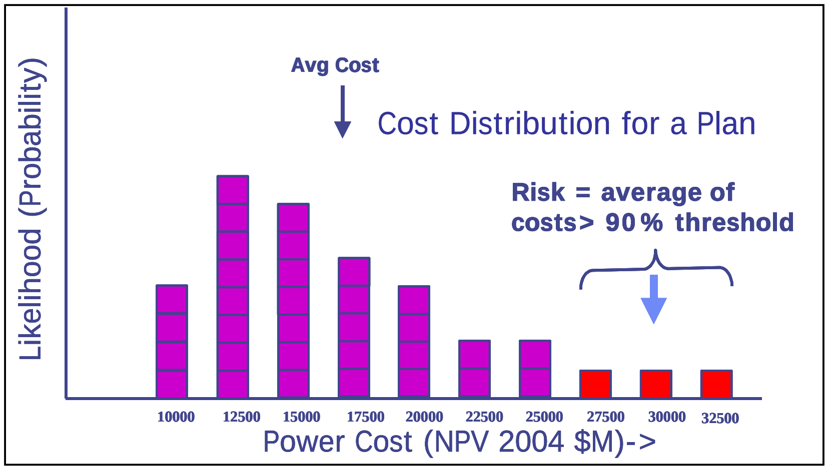


Figure EX-9

THE PLAN

A plan describes the resource actions to be taken over the planning period. The models produce a number of alternative plans, each of which represents the plan with the least expected cost for a given level of risk. The models also identify the plan that is the least cost of all and also the one that exhibits the least risk. Generally speaking, as the risk of plans decrease, their expected cost increases. This is the consequence of the costs of additional resources that are added to mitigate the costs associated with future market price spikes, and as a hedge against the risks of fuel price volatility and possible future carbon dioxide control measures. Of particular interest is what the plans indicate for the next five years, the maximum time before the Council's power plan is revised. There are several strategic conclusions that can be drawn from these results and the results of sensitivity analyses that have been carried out:

- Significant development of conservation is characteristic of all the plans – whether least cost or least risk. For the period of the five-year action plan, the level of conservation represents an increase of approximately 250 average megawatts over the level of regional conservation development during the period 1998-2002. Moreover, the development of that conservation needs to begin now. Failure to develop that conservation has significant cost and risk penalties. It will require accelerating the development of generating resources along with their attendant costs and risks.

- Demand response shows benefits if available at the costs we have estimated. It is dispatched infrequently but, while the benefits are not huge, they are more than cost-justified.
- Also characteristic of all the plans is that there are no significant additions of generating resources during the action plan period. There are several individual utilities that are resource short and will have to acquire additional resources in the next few years. They could fill those needs from existing regional resources, primarily owned by IPPs, if agreements can be negotiated. There are, however, reasons why it may not be possible to do so.
- The role that coal plays is affected significantly by expectations regarding future policies to limit production of carbon dioxide and also by the expectation of high natural gas prices and gas price volatility. Many of the plans include development of a coal-fired plant. Improvements in the efficiency of coal generation, e.g. integrated coal gasification, and the development of relatively low cost carbon sequestration methods would increase the attractiveness of coal generation.
- Wind plays a very significant role in many of the plans. That role is largely one of risk reduction – it provides a hedge against higher and volatile gas prices and carbon dioxide control measures.

The choice of a single plan is not simple. If this were strictly a question of monetary damages, we would not want to increase expected costs (over the least cost plan) any more than the expected reduction in risk. As risk has been defined in this analysis, this would be 10 percent of the reduction in the risk measure. However, looking back on the experience of 2000-2001, it seems clear that "average costs" and costs you could experience at the extremes of the distribution, i.e. in crisis, do not have the same weight. The latter hurt a great deal more. In addition, social and "non-power" economic costs can be significant but are not included in our risk measures. For that reason, as well as judgments regarding reductions in price volatility and the desirability of a diverse and orderly development pattern, a plan that is somewhat more costly but considerably less risky than the absolute least cost plan has been chosen.

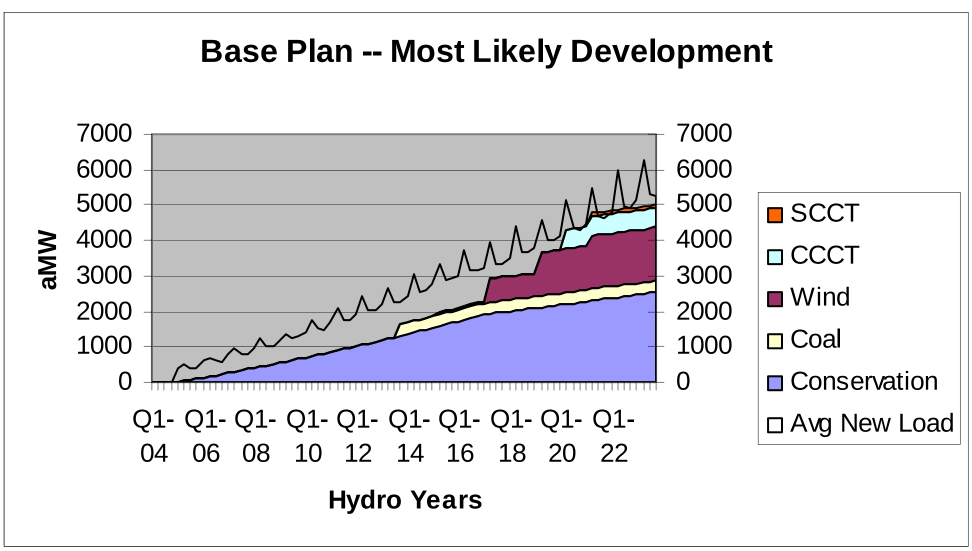


Figure ES-10

The base plan is illustrated in Figure ES-10 for the most likely development schedule. However, for any given future, implementation of the resources could be somewhat sooner or later, at higher levels or lower, or not at all, depending on load growth and other factors.

The Council recognizes that the choice of a base plan is a function of perception of, and tolerance for, risk. This issue is discussed more fully in Chapter 5. The Council encourages a regional dialogue on this issue.

An important point, however, is that absent extremely high growth in demand over the next several years, substantial loss of existing resources, or failure to develop the cost-effective conservation, the plan does not call for significant development of new generating resources before the end of the decade. This means that some of the uncertainties affecting this plan may become clearer before many generating resource commitments need to be made.

However, that does not mean the region should not develop additional resources. The Council's analysis finds that sustained, significant development of conservation now, with a goal of 700 average megawatts over the next five years, to be in the region's interests. Accomplishing this and additional conservation over the remainder of the planning period reduces the average system cost by as much as $2 to $2.5 billion, and reduces risk even more, compared to less aggressive implementation. In the past, the pace of conservation implementation has varied widely from year-to-year as utilities responded to market conditions and other factors. However, our analysis shows that a sustained and significant pace of investment in conservation to be beneficial in terms of reducing exposure to periods of high market prices, fuel price volatility, and possible future carbon penalties.

If the region is in surplus, why are some utilities seeking generating projects now?

- While the region as a whole has excess generating capacity, some individual utilities are energy short.
- Some may need additional peaking capacity.
- Requests for proposals are an efficient tool for assessing available options.
- Most of the surplus generation is owned by independent power producers (IPPs). This power is available to the region. However, utilities may have reasons not to purchase from the IPPs:

-- They may not want to take on additional gas risk. (Most of IPP projects are gas fired.)
-- Transmission limitations may prevent accessing existing generation on a firm basis.
-- They may want to get experience with newer technologies like wind.
-- They may see advantages in building their own:

♦ There can be financial advantages in having a physical asset as opposed to a purchase contract.
♦ Investor-owned utilities can earn a rate of return on projects they own.
♦ Publicly owned utilities can finance projects at lower costs.

The power plan calls for increasing conservation acquisition from 130 average megawatts in the first year to 150 average megawatts in the fifth year of the plan with modest increases in the following years. The Council's initial year target of 130 average megawatts is equivalent to the average amount of conservation acquired by The Bonneville Power Administration (Bonneville), the region's utilities, and the Northwest Energy Efficiency Alliance (Alliance) from 2001 through 2002. It is just over 10 percent higher than the average amount of conservation achieved annually from 1993 through 1996, a period when utilities increased conservation efforts and prior to concerns regarding industry restructuring. This Plan's fifth year conservation target of 150 average megawatts is slightly above the maximum rate of utility system acquisitions of 146 average megawatts.

Over next five years, the implementation of the Council's Plan will require that the region increase its conservation achievements by less than 10 percent compared to sustaining 2001 - 2002 levels of acquisition over this same period. To accomplish this, the Council estimates that regional utility system investments in conservation will likely need to increase by $100 million or roughly one-third over 2001-2002 levels. The Council expects that total utility system investments in conservation needed to achieve its five-year target will be approximately $1.35 billion. This is slightly less than the $1.45 billion (2000$) in utility investments from 1992 through 1996. The increase in utility system investments could be less than this amount depending upon the effectiveness of efforts to improve regional coordination and program implementation; the success of market transformation ventures; and the timing and stringency of energy codes and standards adoption

Why acquire conservation when the region has a surplus of electricity generation?

- Acquiring conservation that costs less than power from existing generating plants reduces the overall cost of the power system because surplus electricity can frequently be sold on the market.
- The conservation needs to be in place if it is to provide protection against future price excursions.

Haven't we acquired all available conservation already?

- Most of the conservation potential identified in this plan is in new technologies and new applications that generally have limited penetration to-date.

Will acquiring more conservation increase electric rates?

- Conservation costs can increase short-term power rates. But the conservation identified in this plan reduces long-term system costs and risks, which translates into long-term bill savings. The increased conservation acquisitions identified in this plan will probably require increasing utility conservation expenditures about one-third over that spent in 2002. That is an increase of less than one percent of the total electric system revenue requirements. Short-term rate impacts could be deferred by financing conservation, although such financing increases conservation costs somewhat.

In addition to conservation, demand response resources in the amount of up to 2,000 megawatts are also developed over the planning period. Demand response is used in roughly half the futures examined. For those periods where it is dispatched, the average level of dispatch is 62 average megawatts over a quarter. But in futures with very high prices, they can dispatch for longer periods to help moderate prices and maintain reliability. Without any demand response resources, the average cost of the power plan increases by almost $100 million while risk is increased by $500 million. The value of demand response is clearly in mitigating the risks of high market prices. There remains, however, some uncertainty regarding the amount and cost of the demand response resource.

Beginning as early as 2009, the power plan calls for being ready to begin actual construction of a coal-fired power plant. Being ready to begin construction means that the process of siting and licensing the necessary projects has already been accomplished and, if necessary, longer lead time activities, like construction of transmission upgrades, have been initiated so that resources can be brought on line as needed. Although not modeled as part of the base plan, sensitivity analysis suggests that serious consideration should be given to integrated coal gasification as a way of reducing risks associated with future carbon emissions reduction policies.

Wind plays a much-expanded role in this power plan. This is the result of a number of actors: possible future policies to reduce the emissions of carbon dioxide, making the use of carbon-intensive fuels risky; the forecast of significant wind plant cost reductions; higher gas prices and the avoidance of fuel price volatility; wind turbine technology improvement; and relatively low integration costs. It also assumes the ability to expeditiously extend transmission service to promising wind resource areas. The uncertainties regarding these factors have been explored through a sensitivity analysis. Because of the significant future role of wind power and the need to resolve these uncertainties before large-scale development is needed, the power plan calls for measured development of commercial scale wind projects at geographically diverse, promising wind resource areas over the remainder of the present decade. The wind incorporated in current utility plans and system benefits charge programs could accomplish this objective.

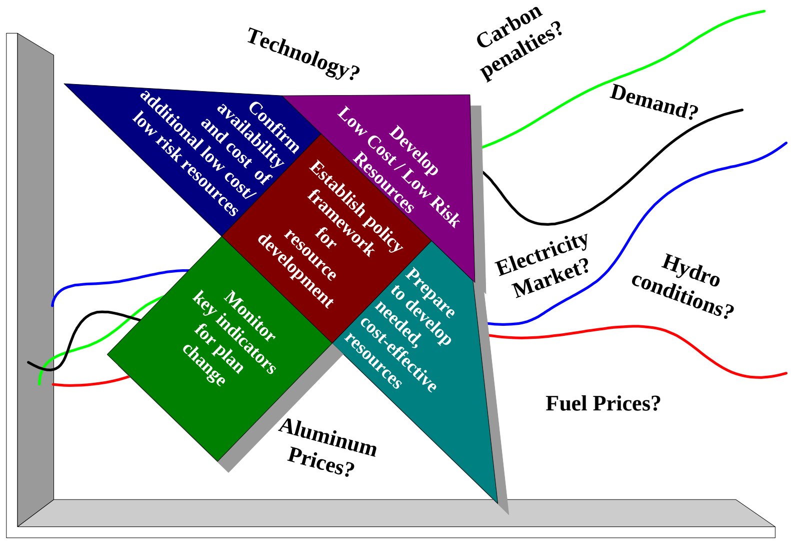
New gas-fired generation does not figure in this power plan until late in the planning period, largely as a consequence of higher gas prices and the expectation of greater volatility in gas prices. Nonetheless, it could figure prominently later in the planning period as the more promising wind sites are developed and carbon emissions concerns become more significant. While not modeled in the base plan, gas-fueled co-generated power from oil sands development in Northern Alberta might be an alternative. Its greater thermal efficiency would improve carbon emissions and reduce fuel costs. Its future depends on the development of transmission from Northern Alberta to bring the power into the region.

Scenarios (Under Development)

[charts showing resource development for *representative* futures and those for which the plan does and does not perform well.] Discussion of these scenarios

STRATEGY FOR AN UNCERTAIN FUTURE

This power plan is about the actions the region needs to take over the next few years to manage costs and minimize risk in an unavoidably uncertain future. The fact that the region as a whole currently enjoys a modest surplus does not mean there is nothing to be done. The elements of the strategy that the Council recommends the region follow over the next 5 years are:



1) Develop resources now that can reduce cost and risk to the region – These include cost-effective conservation, demand response, and lost-opportunity generating resources such as industrial combined heat and power projects.

2) Prepare to develop additional resources – There are actions, like the preservation of permitted power plant sites, permitting of new sites, and the planning, siting and perhaps construction of transmission, that need to be taken to ensure that cost-effective generating resources can be developed with a minimum lead time when they are needed.

3) Confirm the availability and cost of additional resources that promise cost and risk mitigation benefits – These include some newer generating technologies like integrated coal gasification and Alberta oil sands cogeneration.

4) Establish the policy framework to ensure the ability to develop needed resources – There are important policy issues like resource adequacy, transmission governance and management, and the future role of the Bonneville Power Administration that, unless resolved, could impede the development of needed resources.

5) Monitor key indicators that could signal changes in plans – The region needs to be prepared to monitor key factors that will indicate whether the plan is on track or needs to be modified.

MAKING IT HAPPEN – THE ACTION PLAN

The Northwest Power Act requires the Council to prepare a 20-year power plan. Resources are usually long-lived. Because uncertainty and the risks it entails become greater with time, it is important to evaluate the performance of a plan for a long period of time. But no one expects to slavishly adhere to any plan for the entire 20-year planning period. This plan will be revised several times during that period as new technologies become viable, as current uncertainties become certain, and as new uncertainties arise.

However, what is most important for this plan is what we do or don't do in the immediate future, the next few years before a new plan is produced. We will not get a chance to revisit those decisions. We will have to live with the consequences for many years to come. The Action Plan identifies those actions that have to occur over the next three to five years to implement the power plan. The time to begin these actions is now.

Develop resources now that can reduce system cost and risk

Conservation

Conservation is the highest priority resource under the Northwest Power Act. The region has developed nearly 2,500 average megawatts of conservation since its passage at an average levelized cost of approximately 2.5 cents per kilowatt-hour. Despite the conservation that has already been achieved, there remains a significant amount yet to be developed, largely as a result of new efficiency technology.

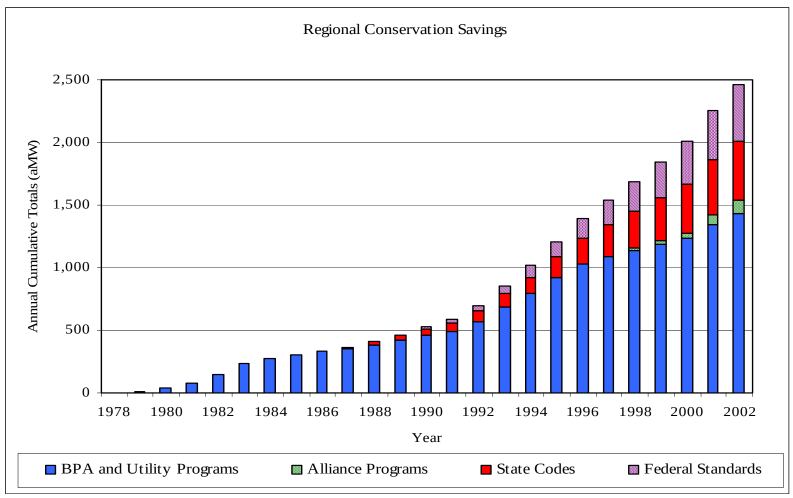


Figure ES-11

Conservation has several characteristics that make it unique when compared to other resources. First, its cost is almost entirely capital, while its operating costs are minimal. This means that, unlike a conventional generating unit, there are no operating costs to be avoided when demand is low. Conversely, compared to generating power plants, conservation always produces savings of some value, and it reduces the risk of increases in fuel prices and increases in the cost of electricity. Second, it has no environmental emissions. This means that conservation reduces the risks associated with future environmental controls. Third, some types of conservation resources are "discretionary," i.e., they can be developed when they are needed. On the other hand, some conservation resources are not discretionary. For these resources, which are the lost-opportunity resources, it is only feasible and cost-effective to capture them when, for example, a building is constructed or an appliance is purchased. Fourth, conservation resources come in small increments and have relatively short lead times for development, assuming the necessary programs and budgets are in place. This means that at least for schedulable conservation, there is some ability to speed implementation up or down in response to prevailing conditions.

Taking these characteristics into account, even though the Council's analysis indicates that we are likely to have relatively ample power supplies for the next few years, there is value in aggressively pursuing the development of conservation. In fact, developing some additional conservation beyond that indicated by short-run power prices provides additional value in mitigating fuel costs, market price, and environmental risks. To achieve this, The Council recommends the following actions:

Increase Regional Conservation Acquisition – The Council recommends that the region target 700 average megawatts of conservation acquisitions from 2005 through 2009. The Council recommends that conservation resource development be split between "lost opportunity" and "non-lost opportunity" or "discretionary" conservation, and across all sectors.[2] The recommended regional target for non-lost opportunity conservation resource development should be 120 average megawatts annually. The recommended target for lost opportunity conservation is to increase acquisition of these resources so that within twelve years the region is capturing at least 85 percent of their annual cost-effective potential. Under the Council's medium load growth forecast lost opportunity acquisitions would total 100 average megawatts from 2005 through 2009 as these programs increase. Figure ES-12 shows the Council's recommended annual minimum targets by sector and resource type.

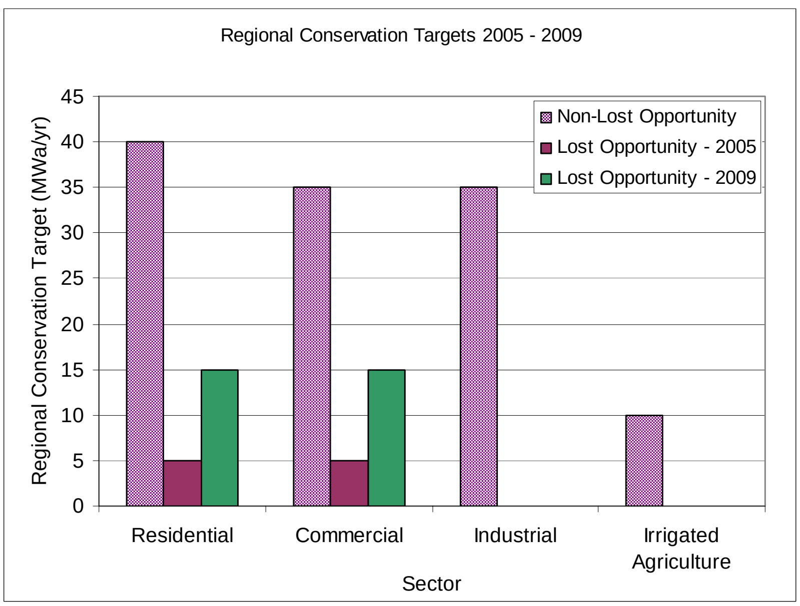


Figure ES-12

The Council's analysis indicates that regional investment in conservation at this level has a much greater probability of producing a more economical and reliable power system than alternative development policies. The Council recognizes that the conservation target represents an increase over recent levels of development. However, the Council's analysis of the potential regional costs and risks associated with developing lesser amounts of conservation demonstrates that failure to achieve this target exposes the region to substantially higher costs and risks.

[2] A lost opportunity resource is a conservation measure that, due to physical or institutional characteristics, either cannot be developed or cannot be developed cost-effectively unless actions are taken at a particular time, e.g. when a building is being constructed or an appliance is sold.

The development of conservation resources is a major contributor to the "hedge" against future market price volatility. As described in the discussion of the results of the portfolio analysis (Chapter 7), capturing these conservation resources reduces both net present value system cost and risk.

> **ACTION: Ramp up lost opportunity resource acquisitions** – Many of the lost opportunity resources identified in this power plan are relatively new and do not have established programs or approaches for their acquisition. Utilities, with the support of the regulatory commissions, Bonneville, System Benefits Charge Administrators (SBC Administrators), The Alliance, other program operators and state and federal standard setting agencies should increase the annual acquisition of lost-opportunity conservation resources. Existing programs should be expanded, new programs initiated, and codes and standards improved so that within twelve years from the adoption of this plan the region is capturing at least 85 percent of the cost-effective lost-opportunity potential available annually.[3]

> **ACTION: Increase non-lost opportunity resource acquisitions --** Utilities, with the support of the regulatory commissions, Bonneville, SBC Administrators, the Alliance and other program operators should increase the annual acquisition of non-lost-opportunity (discretionary) conservation resources to capture at least 120 average megawatts of regionally cost-effective savings annually within one year of the adoption of the power plan. This level of annual non-lost opportunity resource acquisition should be sustained for at least five years.

Strategically plan conservation deployment and provide adequate regional coordination and administration – Achieving the Council's recommended conservation target will require significant new initiatives, including regional and local acquisition programs, improved energy codes and equipment standards, and market transformation ventures. In addition, the Council believes that acquiring cost-effective conservation in a timely and cost-efficient manner requires thoughtful development of mechanisms and coordination among many local, regional, and national players. The Council recognizes and supports the desire of many public utilities in the region to take greater responsibility for resource development instead of relying on Bonneville. Nonetheless, the Council believes coordinated efforts will be an increasingly necessary ingredient to successfully develop the remaining conservation potential.

The boundaries between direct acquisition approaches, market transformation, infrastructure support, and codes and standards are blurry. In fact, for much of the conservation resource, efforts are needed on all these fronts to bring emerging efficiency measures into common practice or minimum standard. Of increasing importance is improved coordination between local utilities, SBC administrators, the Alliance, Bonneville, the states, and others. Improved coordination is needed to assure that the

[3] Lost-opportunity potential varies year-to-year depending on the numbers of new buildings constructed, new appliances, and equipment installed. Rates of new installations tend to follow economic cycles, so the Council recommends a maximum penetration rate of 85 percent rather than an energy target. Under medium load growth, an 85 percent penetration rate for lost-opportunities would be about 70 average megawatts per year.

region can take advantage of efforts to target initiatives where they have the most impact on the resource development and to capture synergies of approach.

The Council believes that in order to efficiently accomplish the conservation targets set forth in this power plan, the region needs to resolve key strategic issues including 1) defining Bonneville's role in conservation implementation; 2) developing a mechanism and funding for regionally administered acquisition and assessment efforts; 3) defining the role, funding, and structure of the Regional Technical Forum; and 4) developing a mechanism and funding for regional conservation research and development.

> **ACTION: Develop a Strategic Plan for Conservation Acquisition --**The Council, with Bonneville, utilities, SBC administrators, the Alliance, regulators, state energy offices, the efficiency industry, and other stakeholders will convene a forum to develop a strategic plan to achieve the conservation targets set forth in the power plan. This strategic plan will establish the implementation role that Bonneville, utilities, SBC administrators, the Alliance, regulators, State Energy Offices, and the Regional Technical Forum (RTF) will play, and it will allocate the share of the regional conservation target to be accomplished by each of these major entities and resource development mechanisms. The strategic plan will set forth regional coordination and administration recommendations. The Council will convene the forum within six months of issuing its Fifth Power Plan. The resulting strategic conservation plan should be presented to the Council within one year.

The Council believes any strategic plan will require specific actions and increased efforts in the categories of local acquisition, market transformation, codes and standards, and regional coordination/acquisition. While the Council cannot prejudge the specifics of the strategic action plan, recommended actions and approximate budget ranges are set forth here for each of these categories. More detailed discussion of the conservation acquisition approaches by sector and measure are in Appendix XX.

> **ACTION: Increase local acquisition budgets** – Based on historical costs, the Council believes that an aggregate utility system annual investment of between $200 and $260 million, excluding market transformation and regional coordination and acquisition, will be needed to achieve the 700 average megawatt target over the next five years.[4] The amount each utility or system benefits charge administrator will need to invest to meet its share of the regional target will depend on its customer mix, growth rate, local economic conditions, program designs, and other factors. The Council estimates that Bonneville and Northwest utilities invested just over $200 million (year 2000 dollars) in conservation in 2002. Therefore, the Council anticipates that local conservation

[4] The Council's estimate of the amount of money to meet the plan's target is based on the estimated capital cost of discretionary and lost-opportunity savings identified in the conservation assessment targeted over the next five years, and the share of those costs expected to fall on the utility system. Total resource costs increase from approximately $270 million to nearly $420 million per year over the five-year time frame (year 2000 dollars). The Council estimates that annual utility system costs would be approximately $240 million in 2005 and increase to $300 million by 2009. Of that, about $40 million per year may be directed to market transformation and regional coordination and acquisition activities. The estimated utility cost is $1.9 million per average megawatt over this five-year period. To put this into historical perspective, the average utility cost of conservation acquired between 1991 and 2002 was $2.2 million (2000$) per average megawatt. However, the average cost of utility acquired conservation, including savings from Alliance programs since 1997, is $1.4 million (2000$) per average megawatt.

acquisition expenditures will need to increase over current levels in order to fully capture conservation's benefits.

ACTION: Expand market transformation initiatives– A portion of the regional conservation target can be acquired most efficiently and effectively through market transformation. The Council's conservation analysis indicates that there are additional candidates for new or expanded market transformation ventures. The Council estimates annual Alliance budgets needed to mount these new or expanded market transformation efforts are in the range of $30 to $35 million per year. Current Alliance budgets are about $20 million per year. Therefore, the Council anticipates that market transformation acquisition expenditures will need to increase over current levels in order to fully capture conservation's benefits.

ACTION: Revise and adopt state and federal energy codes and efficiency standards that capture all regionally cost-effective savings – Codes and standards are the most effective method to capture some of the lost-opportunity conservation potential identified in this power plan. In order to achieve the savings from new and revised codes and standards, actions must be taken by federal and state government, utilities, SBC administrators, and the Alliance. Specifically:

- The states should adopt efficiency standards identified in this power plan for appliances and equipment not pre-empted by federal law including, but not limited to, commercial refrigerators, freezers, icemakers, power transformers, and AC/DC power converters.
- The U.S. Department of Energy should adopt or revise standards identified in this power plan for residential clothes washers, dishwashers, refrigerators and freezers, and other appliances and equipment currently covered by federal law.
- The U.S. Department of Housing should revise its efficiency standards for new manufactured homes so that these standards satisfy the Council's Model Conservation Standards.
- Bonneville, Utilities, SBC administrators, and the Alliance should implement the Council's Model Conservation Standards for New Residential and Commercial Buildings Programs within the next five years.
- State and local code authorities should revise their existing energy codes so that these codes provide savings equivalent to the Council's Model Conservation Standards for New Residential and Commercial Buildings on their next state building code update cycle.
- The Alliance, utilities, SBC administrators, and states should provide ongoing annual funding, technical, and political support of timely adoption of federal standards to capture cost-effective savings identified in the Fifth Power Plan.

The Council will provide assistance to states and their stakeholders in the development and passage of improved energy codes and standards and will work through the relevant federal processes to advocate for improved codes and standards.

Develop mechanisms and funding for regional coordination and limited regional acquisition – The Council also believes that a significant share of the savings identified in this power plan can be more effectively and efficiently acquired through regionally administered programs or, at a minimum, will require a regional scope to achieve economy of scale or market impacts. These actions may not qualify as market transformation as currently defined. They include regional coordination and potential acquisition payments for efficient AC/DC power converters, commercial refrigerators and freezers, residential heat-pump water heaters, and Energy Star manufactured homes and could cost $5 to $10 million annually over the action plan period. In the past, Bonneville has played a similar role and could do so in the future if the region so decides.[5] The Alliance could also coordinate such activities if its market transformation mission were expanded. The Council intends to use the strategic planning process identified earlier to develop a solution to this problem.

> **ACTION: Within 12 months, the Council, regulators, Bonneville, utilities, SBC administrators, the states, and the Alliance establish a mechanism and funding to develop regional coordination and acquisition not falling under the category of market transformation --** The options to be considered include existing Bonneville, or expanding the mission and budget of the Alliance, creating another mechanism to target actions best administered regionally, or using some combination of these three options. The Council estimates regional coordination and acquisition activities will cost in the range of $5 to $10 million per year to reach targeted conservation levels. As with market transformation, care should be taken to insure that a regional organizational framework of utilities, contractors, and government agencies is in place in order to successfully carry out the day-to-day acquisition activities.

Track regional conservation accomplishments – This power plan places considerable reliance on conservation. It will be essential to track regional accomplishments.

> **ACTION: Within 12 months of the adoption of the power plan, the Council, regulators, Bonneville, utilities, SBC administrators, the states, and the Alliance should establish a mechanism for the annual reporting and tracking of regional conservation investments and accomplishments --** The Regional Technical Forum or the state energy agencies should be considered as potential vehicles for accomplishing this tracking. State government agencies could add conservation data to the data already collected from utilities such as fuel mix disclosure information. It is essential that sufficient resources, financial and otherwise, be committed to this activity.

Address important barriers – Utility implementation of conservation has historically faced several barriers. New barriers may emerge if changes like those proposed for the Bonneville Power administration take effect. Efforts should be made to remove these barriers.

> **ACTION: Regulators and local boards and commissions should establish criteria and processes for evaluating and reflecting the value of conservation as a hedge against future risks --** This should be accomplished in time to be incorporated in subsequent utility integrated least-cost plans. The Council will offer its assistance in these efforts.

> **ACTION: If revenues lost as a result of conservation remain as significant barriers to implementing cost-effective conservation targeted in this plan, state and local**

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[5] For example, Bonneville administered the Manufactured Housing Acquisition Program (MAP) on behalf of all of the region's public and investor-owned utilities.

regulators and utilities should develop and implement strategies to mitigate conservation impacts on cost recovery -- Options to be considered would include modifying rate design to reduce the fixed costs recovered in per kilowatt-hour charges combined with carefully designed increasing block rates. Alternatively, mechanisms to separate revenues from kilowatt-hour sales should be considered provided that the separating is limited to the effects of conservation.

ACTION: Consider financing conservation investments -- Because conservation costs are all capital, and because they are often expensed, they tend to have short-term rate impacts. We have estimated the increased conservation acquisitions identified in this plan will require an increase of less than one percent of total electric system revenue requirements over that spent in 2002. Nonetheless, cash-flow constraints and competitive pressures on their rates often limit utilities. Financing conservation in the same way that other resources are financed can mitigate these short-term rate impacts, although at some expense of increasing long-run costs. However, the fact that conservation is not a physical asset that the utility owns can be a barrier. This can be reduced if not overcome by if the states adopt legislation defining conservation investment as a non-recourse regulatory asset. Such an asset would be would be backed by states ability to guarantee cost recovery. This instrument could be available to system benefit charge administrators as well as to utilities.

ACTION: Low Income Weatherization—Cost-effective conservation acquired as a result of low-income weatherization programs has proven to be a useful addition to the region's conservation portfolio. Bonneville and utilities should continue to provide support for this activity where cost-effective savings are achieved.

ACTION: System Benefits Charges – Two Northwest states have established system benefits charge approaches to conservation. In a system benefit charge approach, conservation is funded by charge on all customers' bills and an administrator, usually other than the utility, disperses funds for conservation acquisition. Other states have adopted similar approaches. But these systems are new and have a limited track record. If utility disincentives seriously impede utility investment in conservation, consideration should be given to a system benefit charge approach to conservation funding and acquisition. Because the limited track records of these approaches, the Council will review the performance and effectiveness of Oregon, Montana and other SBC systems around the country by 2008.

ACTION: As the Bonneville Power Administration's role in power supply is altered, avoid or remedy disincentives to utility conservation – The effort to alter Bonneville's role in power supply is likely to involve an allocation of power from the existing federal system to qualifying customers. Customers are concerned that the allocation could create a distinctive to conservation. Bonneville should design and implement allocation methodologies and net requirements calculations to avoid disincentives to utility conservation acquisition.

Demand Response

Demand response is an appropriate, voluntary change in the level of electricity use when electricity supply is tight. Demand response can be accomplished by a variety of approaches, which can be generally grouped in two categories: price mechanisms and demand "buybacks." While the Council believes there are some benefits to price mechanisms that deserve to be more fully explored, for now we have limited our analysis to voluntary buybacks similar to those employed by several regional utilities during the 2000-2001 electricity crisis.

This is the first Council power plan in which demand response is treated as a resource. The region has limited experience with demand response, but that experience has demonstrated that it offers substantial potential benefits in terms of limiting high price excursions and the ability to exercise market power in tight markets. The size and value of this resource, however, are somewhat uncertain. For the portfolio analysis, we have conservatively estimated that 2,000 megawatts of demand response could be developed by 2020. We have estimated its "operating" cost would be $150 per megawatt-hour, with a fixed cost of $5,000 per megawatt-year for the first year and $1,000 per megawatt-year thereafter. Our portfolio analysis further suggests that if we *fail* to implement demand response, the potential increase in expected system cost could be in the $100 million (net present value) range while system risk would increase by $500 million. Demand response provides benefits in the form of greater system reliability—utilities have a better idea about what loads they can easily shed in an emergency—and these reliability benefits can be included in the price utilities may offer to these customers for the right to reduce load.

The Council's recommended actions are designed to build on the region's recent experience, to expand the region's understanding of the demand response resource, and to guide future policies affecting demand response. Specifically:

> **ACTION: Expand and refine existing programs** – Bonneville and utilities, with regulators' approval, should maintain, and begin to expand and refine the demand response programs they have developed in the past few years. This should begin immediately. For example, utilities should maintain their ability to buy back demand when conditions warrant, and should work to expand participation in these programs. The utilities should work to reduce the transaction costs of these programs by streamlining recruitment of participants, notification of buyback opportunities, and verification of, and compensation for, demand reductions.
>
> **ACTION: Develop cost-effectiveness methodology for demand response** – Regional parties including, but not limited to Bonneville, utilities, regulators, and the Council should develop a clear cost-effectiveness methodology for demand response no later than 2006. While the general principle of avoided cost is well accepted, there are practical difficulties in calculating avoided cost in our power system because of its large hydroelectric component and very substantial transmission links to other regions. A clear and widely accepted methodology would ease the development and adoption of demand response programs. The Council could serve as the convener of such an effort, if necessary.
>
> **ACTION: Incorporate demand response in integrated resource plans --** Regulators should require utilities to incorporate demand response fully into utilities' integrated resource plans (IRPs) starting with the next round of IRPs. Utilities have made a beginning, but more needs to be done. This work should include refined estimates of the size of the resource, which is likely to require pilot programs and further analysis.
>
> **ACTION: Evaluate cost and benefits of improved metering and communication technologies –** Utilities, with participation by regulators, should evaluate the costs and benefits of improved metering and communication equipment. The lack of such equipment is an obstacle to securing the participation of many customers in demand response programs. Over time, this equipment has become cheaper and more capable. Evaluations of cost-effectiveness of demand

response should use the net cost of the necessary metering and communication equipment, after the equipment's other benefits have been taken into account.

ACTION: Monitor cost and availability of emerging demand response technologies -- The Council, Bonneville, and utilities should monitor emerging demand response technologies. For example, intelligent appliances that can cycle in response to system frequency have potential to significantly reduce the cost of maintaining system stability.

ACTION: Explore ways to make price mechanisms more acceptable – Regional parties, including, but not limited to, utilities, regulators, and the Council should explore ways to make price mechanisms more acceptable as a potential means of achieving demand response. In many cases, price mechanisms offer significant advantages compared to buybacks, such as lower transition costs and wider reach. However, concerns such as fairness and price stability have prevented much adoption of price mechanisms in our region. It is worth a serious effort to see if these legitimate concerns can be met while achieving some of the advantages of price mechanisms. This should be carried out by 2006. The Council could serve as the convener of such an effort, if necessary.

ACTION: Transmission grid operators should consider demand response for the provision of ancillary services, on an equal footing with generation – It seems likely that this will be facilitated by the development of a formal market for ancillary services, but even if that formal market does not develop, demand response should be able to compete to provide ancillary services.

Cost-effective lost opportunity renewable and CHP generating resources

Regionwide, bulk power generating resources appear unlikely to be needed at the earliest until late in the action plan. However, opportunities for the development of economic renewable energy and combined heat and power projects are likely to surface occasionally during this period. Examples might include industrial or commercial combined heat and power (CHP) projects, landfill, animal waste or wastewater treatment plant energy recovery projects, hydropower renovations, forest residue energy recovery, and remote photovoltaics. The opportunity to economically develop these projects is often transient, created by needs not directly related to electric power production, such as a waste disposal problem, equipment upgrading, or replacement of new commercial and industrial development. Utilities, organizations administering resource development incentives, and others able to facilitate resource development should establish procedures to identify, evaluate, and secure these opportunities as they arise.

ACTION: Utilities, with the support of the regulatory commissions, and entities administering resource development incentives should identify cost-effective renewable and CHP generating potential – Identification of potential projects is a precursor to the acquisition of cost-effective projects. One way of identifying such projects is for utilities to conduct inventories when developing Integrated Resource Plans. Other approaches include all-source Requests for Proposals and open windows for unsolicited proposals. These efforts should be tailored to identify potential lost opportunity projects. This should be accomplished by 2007.

ACTION: Utilities with commission support, and entities administering resource development incentives should establish current, accurate, and comprehensive procedures and criteria for the evaluation of renewable and CHP projects –The evaluation of renewable and CHP projects should be based on an accurate assessment of project costs and benefits. Criteria for evaluating resource cost-effectiveness should be current, and accurately reflect all significant costs and benefits of acquiring the resource. This includes the energy value, possible value of capacity and other ancillary services, offset transmission and distribution costs and losses, and environmental effects. Cost effectiveness criteria should account for significant risks and uncertainties. This should be accomplished by 2007.

ACTION: Utilities, with commission support, should remove disincentives to utility acquisition of power from projects owned or operated by others – The inability of an investor-owned utility to receive a return on risk for funds associated with power purchase agreements, or an investment in generation owned or operated by others may create an economic disincentive for securing these resources. Utilities and commissions should work to reduce or remove these disincentives where present. This should be accomplished by 2007.

ACTION: Utilities, with commission support, should adopt uniform interconnection agreements, technical standards, and accurate and equitable standby tariffs – Uniform interconnection standards and fair and equitable standby tariffs will facilitate development of cost-effective customer-side generation. Utilities, with the support of their commissions where applicable, should adopt uniform interconnection agreements and technical standards, consistent with FERC jurisdiction. Standard agreements should be transparent, free of unnecessary complexity, and expeditiously processed. Standby tariffs should accurately and equitably reflect the costs and benefits of customer-side generation. This should be accomplished by 2007.

ACTION: Utilities with commission support, and entities administering resource development incentives, should acquire cost-effective lost opportunity renewable and CHP projects -- Utilities should acquire, either by power purchase or investment, cost-effective renewable and CHP projects. This should be in effect by 2006.

ACTION: Utilities, with commission support, should facilitate the sale of excess power from customer-side generation – The economics of CHP and other customer-side generation can be improved by the ability to market power in excess of customer needs. Utilities, with the support of their commissions where applicable, should facilitate the sale of excess customer-generated power. Possible means include the expansion of eligibility for net metering agreements and by offering accurate and equitably priced distribution system access for sale of excess power. Because the seasonal and daily variation of the value of power is expected to become more significant in the future, net metering should be based on time of day metering. This should be accomplished by 2007.

Prepare to develop additional generating resources when needed

Meeting the conservation goals of this power plan is expected to defer the need for major new generating resources on a regionwide basis until 2013 under most likely conditions. The earliest observed major generating resource in-service is 400 megawatts of coal in 2013. Later completions are observed in many cases, but the power plan requires that capacity be capable of service by the earliest observed date. Completion of a coal-fired power plant in 2013 will require preparations for construction to commence in 2009 and mobilization by early 2010. This will require the availability of at least 400 megawatts of fully permitted potential capacity, including transmission interconnection by 2009. The pre-construction development of a coal-fired project is estimated to require up to three years. This implies that pre-construction development of potential coal-fired project should commence no later than 2006.

New generating capacity may be needed earlier if conservation goals fail to be met. Low levels of conservation acquisition lead to an observed need for 100 megawatts of wind in early 2009, followed by an additional 100 megawatts in 2010, and 800 megawatts in 2012. Coal is required at about the same time as in the base case. Additional resources are required later; however, construction lead times are such that no action regarding these resources is required during the period of the action plan.

The power plan anticipates development of a substantial amount of wind capacity. Though development and operation of the current regional wind projects has been successful, uncertainties remain with respect to the ability to develop the much larger amounts of wind of the least-risk plan. Among these uncertainties are the availability of financial incentives, continued equipment cost reduction, and the cost of integration. If the future cost of wind power is greater, or the availability less than assumed for the power plan, other resources may have to be substituted for the wind power.

Maintain an inventory of ready-to-develop projects

Permitting is a time consuming, but relatively inexpensive portion of the project development process. Project development lead-time and exposure to the risks of shortage and price volatility can be reduced at low cost by maintaining an inventory of ready-to-develop projects. The Council recommends a regional inventory of ready-to-develop projects, sufficient to meet possible needs under the least risk plan and plausible deviations from that plan.

> **ACTION: Permitting agencies and project developers should maintain an inventory of ready-to-develop projects for possible future needs** – The recommended minimum inventory is shown in Table ES-3. This capacity should be sited and permitted, with preliminary design complete, transmission requirements identified, and otherwise ready to construct consistent with the possible need to postpone construction until needed.

Table ES-3 – Generating resource development schedule

	Cumulative capacity (MW)	Ready to construct beginning in	Possible need by beginning of
Wind	100	2008	2009
Wind	200	2009	2010
Coal	400	2009	2013

Resolve uncertainties associated with large-scale wind development

The plan foresees the construction of up to 5,000 megawatts of wind capacity in the Northwest over the next 20 years. Wind plays this major role for several reasons: the probability of more aggressive policies to reduce carbon dioxide production; an abundant quality resource; expectations of continued wind plant cost reduction and performance improvements; relatively low integration costs; and the timely availability of electrical transmission service at promising wind resource areas. Uncertainties associated with these assumptions must be resolved to confirm the potential role and facilitate future large-scale development of wind power when needed.

ACTION: Utilities, developers, Bonneville, and entities administering resource development incentives should confirm cost-effective large-scale wind power development capability -- An effective way to resolve the uncertainties regarding large-scale deployment of wind generation is to develop commercial-scale pilot wind power projects at promising wind resource areas. While somewhat expensive if developed in advance of need, actual projects appear to be a more certain approach to resolving these uncertainties than work in the abstract as recommended in earlier plans. Construction, on average, of one commercial-scale project per year over the five-year course of the action plan could confirm up to five promising resource areas, and provide information needed to help resolve the principal uncertainties associated with subsequent large-scale development of the resource. A viable commercial-scale project is about 50 megawatts in capacity. Most of this can be provided by projects developed through the efforts of entities administering resource development incentives and by utilities planning the near-term acquisition of wind power. Accomplishing this will require that project selection, development, and operation support the objectives of this action. Data required for the assessment of issues such as the cost of integration and benefits of geographic diversity must be available to researchers.

When developing the first project at an undeveloped promising wind resource area, the acquiring entity (utilities, Bonneville, or entities administering resource development incentives), working with the project developer should seek to advance or achieve the following objectives: (1) Assessment of the development potential of the resource area as a whole, including the wind resource, environmental issues, and transmission and other infrastructure requirements; (2) Establishing long-term wind monitoring capability where none exists for the site; (3) Monitoring wind power cost and performance trends; (4) Assessing the cost of firming and shaping, including the possible benefits of geographic diversity; (5) Improving the understanding of the capacity value of wind; (6) Securing the permits, to the extent feasible, for development of the ultimate potential of the resource area; and (7) Strengthening regional wind development infrastructure. The Council will monitor and support these efforts.

ACTION: Utilities and Bonneville should develop products for the firming and shaping of wind – A competitive slate of firming and shaping products will facilitate timely and economic development of wind power. The Council encourages Bonneville, utilities and others that have resources suitable for providing shaping and firming services to aggressively develop and market these products.

Encourage the use of best available generating technology

Under the power plan, construction of new bulk generating capacity is unlikely to commence prior to 2009. During the interim, advanced coal, natural gas, and wind technologies offering improved cost and performance characteristics are expected to become commercially available. Near-term examples are likely to include coal gasification combined-cycle power plants and advanced gas turbines. Though these technologies may initially cost more than established technologies, the reduction in system cost and risk may be worth the cost increment and residual uncertainty associated with the use of new technologies.

ACTION: Project developers, federal, state and local permitting agencies, utilities with the support of their commissions, architect-engineering firms, and financing entities should seek the use of the best available generating technology for new power plant construction – Though there may be additional costs and uncertainties associated with state-of-the-art technologies, the resulting improvement in thermal efficiency and environmental characteristics may, on net, reduce future cost and risk to the owner and to the power system. Project developers, state and local permitting agencies, utilities, commissions, architect-engineering firms, and financing agencies are encouraged to routinely consider state-of-the-art generating technologies for new power plant construction. The costs and benefits of these technologies should be evaluated using state-of-the-art risk analysis techniques.

Plan for needed transmission

Transmission planning and construction can be the longest lead-time item in power plant development. Efforts should continue to identify the transmission requirements to connect load to areas of likely power plant development, and to undertake preliminary planning.

ACTION: Bonneville and other transmission providers, permitting agencies, and project developers should plan for long-distance transmission needs to support the resource development called for in this plan -- The Council supports the current efforts of the Northwest Transmission Assessment Committee (NTAC) to undertake such planning. This should be a priority function for any regional transmission entity that may be formed.

Improve utilization of available transmission capacity

Some regional transmission paths are physically under utilized although they have little available contractual transmission capacity. The result is an inefficient use of transmission that can be an impediment to development of needed resources. Bonneville has undertaken some efforts to improve utilization of transmission capacity within its control area. This effort, while helpful, is necessarily limited by the fact that it cannot encompass the larger Northwest grid, and by the existing scheduling rules for transactions that cross control area boundaries. Dealing with this problem across the wider regional grid should be a priority for any regional transmission operator that may be formed.

ACTION: Bonneville and other transmission providers should work to improve utilization of available transmission capacity -- Dealing with this problem across the wider regional grid should be a priority for any regional transmission entity that may be formed. Should this effort fail, transmission providers and control areas should work cooperatively to improve utilization of transmission capacity across the regional grid. This should be completed by 2007. A useful but limited first step could be broader participation in WesTTrans. This OASIS site provides a broader mechanism for facilitating a secondary market in transmission capacity than do single provider OASIS sites. WesTTrans could begin to address the discrepancy between physical capacity and contract path limitations by developing a common ATC calculation. Bonneville and other Northwest transmission owners should participate in this initiative.

Develop additional generating resources when needed

Under plausible conditions, new bulk electrical generating resources may be needed on a regionwide basis as early as 2009. Individual situations may require individual utilities to acquire new generation prior to this time. When new resources are needed, the Council encourages utilities to consider all available options, and to consider the effects of risk and uncertainty on a resources cost-effectiveness using the best available analytical techniques.

ACTION: Utilities, with the support of their commissions, should acquire the best available generating resources when needed – Utilities, when seeking additional generation, should ensure that non-generation alternatives, of equal or lesser cost, are available to meet needs; that all feasible options are considered; that alternatives are evaluated using state-of-the-art methods of assessing costs and benefits; and that all significant risks and uncertainties are considered over the anticipated life of the project. Other considerations equal, the generating resource priorities of the Northwest Power Act should apply.

Confirm the availability and cost of additional resources with cost and risk mitigation benefits

Oil Sands Cogeneration

The oil sands of Northern Alberta contain the largest petroleum deposits outside the Middle East. The resource is in the form of highly viscous bitumin. Large quantities of steam are required to recover the bitumen, which is then processed into a synthetic crude oil. The steam can be produced using gas-fired boilers, however it is more efficient to produce the steam with cogeneration of electricity. Though several hundred megawatts of cogeneration capacity is operating in the oil sands region, additional cogeneration development is constrained by the ability to transmit electricity from the oil sands region to electrical load centers. A proposed 2,000 megawatt DC transmission line from the oil sands areas in Alberta to Celilo would open the oil sands region to additional cogeneration development and provide a new generating resource option to the Northwest. Preliminary cost estimates suggest that this resource, which could be available about 2011 is competitive with new natural gas combined-cycle and coal-fired power plants located within the Northwest. Moreover, the high thermal efficiency of cogeneration somewhat insulates these plants from gas price uncertainties and the possible impacts of climate control policy. Furthermore, it is possible to fuel the cogeneration plants with synthetic gas produced by gasification of byproducts of the bitumin refining process.

ACTION: Bonneville and other regional transmission providers should support efforts to refine the design and cost estimates for a transmission intertie from the oil sands region to the Northwest -- Efforts are currently underway to refine the design and cost estimates for a transmission intertie from the oil sands region to the Northwest. The intertie would provide a potentially attractive resource opportunity to the Northwest, and possibly strengthen the Northwest transmission grid. Though the initiative is private, the potential benefits of the proposal warrant the cooperation of Bonneville and other Northwest transmission providers and potential participants in providing constructive review of the proposal.

Coal Gasification

Coal gasification power generation offers the opportunity for improving the economic and environmental aspects of electricity from coal, an abundant and low-cost energy resource readily available to the region. Gasification technology can also provide the opportunity for economic separation of carbon dioxide for geologic sequestration. Though demonstration coal gasification power plants are successfully operating, initial startups have been long and fraught with reliability problems. Overall, plant performance warrantees have been lacking, precluding financing. Also, experience with Western sub-bituminous coals is limited. Recent developments, including acquisition of rights to the Chevron-Texaco gasification process by General Electric, and the announcement by AEP of its intent to construct one or more 1,000 megawatt coal gasification power plants indicate that the technology is approaching commercialization. While resolution of the remaining barriers to commercialization of coal gasification power generation technology are national in scope, the region should be supportive of federal and other efforts to commercialize coal gasification power generation.

> **ACTION: The Council, states, and utilities should monitor and support efforts to commercialize coal gasification power generation.**

Carbon Sequestration

Geologic sequestration of carbon dioxide may offer a means of reducing carbon dioxide release to the atmosphere while preserving the ability to use coal and other fossil resources for power generation. However, suitable geologic sites need to be identified and tested. Geologic formations potentially suitable for carbon dioxide sequestration are found in eastern Montana and southern Idaho.

> **ACTION**: **The Council, states, and utilities should support and monitor efforts to develop carbon sequestration technology appropriate for Northwest application –** Efforts such as the Northern Rockies and Great Plains Regional Carbon Sequestration Partnership, led by Montana State University, charged with identifying and cataloging promising geologic and terrestrial storage sites and helping define carbon-sequestration strategies should be supported.

Energy Storage Technologies

Emerging energy storage technologies such as regenerative fuel cells offer potential to firm and shape solar and wind generation and to support peak period demand.

> **ACTION: Bonneville, the Council, states, and utilities should support and monitor efforts to perfect energy storage technologies with Northwest application potential.**

Demonstration of Renewable and High Efficiency Generation with Northwest Potential

Routine commercial financing of new technologies and applications requires the successful development, construction, and operation of commercial-scale demonstration projects. Commercial demonstration of promising resource and technology applications with potentially cost-effective Northwest application would confirm their viability in the region. These could include various niche biomass energy recovery applications, forest residue energy recovery, industrial and commercial CHP applications, and photovoltaic applications. Successful completion of these projects will assist engineering, permitting, and financing of subsequent development.

> **ACTION: Utilities, with the support of their regulatory commissions, states or other organizations administering resource incentives, equipment vendors, and project developers should support demonstration of standardized renewable energy and CHP applications with extended near-term Northwest potential**.

Establish the policy framework to ensure the ability to develop needed resources

Resource Adequacy

One of the factors behind the Western electricity crisis of 2000-2001 was resource inadequacy. The analysis done for this plan suggests that there are two kinds of resource adequacy. Physical adequacy means having sufficient resources to prevent the involuntary loss of load. However, economic adequacy is a higher standard that requires sufficient resources to reduce the risk of exposure to unacceptably high power prices. The region needs to address both. If Bonneville's role in meeting the region's load growth is reduced, additional entities that have not had direct responsibility for assuring adequate resources will play an important role. This is not merely a regional issue, because the Northwest is part of an interconnected Western system. This means the region must work with other interests in the West to develop a system that will assure adequacy; recognize the legitimate differences within the West; and ensure that all responsible entities bear their share of the responsibility. Because the Northwest does not face immediate resource needs, the region has some time to address these issues, but we must make sure that time is not wasted. To assure adequacy the region needs to:

> **ACTION**: **Establish regional and West-wide reporting standards for the assessment of adequacy –** It is essential that there be accurate, consistent, and transparent information by which the adequacy of the power supply can be judged. The Council intends to continue to work with such entities as the Northwest Power Pool (NWPP), the Western Electricity Coordinating Council (WECC), and the Committee on Regional Electric Power Cooperation to establish reporting standards no later than July of 2005.
>
> **ACTION**: **Carry out a process to establish voluntary adequacy targets –** Mandatory adequacy standards could be established if the North American Electric Reliability Council is given the necessary authority. However, it is far from certain that will happen. More immediately, the Council should work with such entities as the NWPP, the WECC, and the Committee on Regional Electric Power Cooperation to establish voluntary adequacy targets and reporting requirements. These targets must be appropriate for the Northwest and sub-regions within the Northwest, and compatible with targets or standards established elsewhere in the Western Interconnection. This should be accomplished no later than January of 2006.
>
> **ACTION: Improve consideration of risk in integrated resource planning –** Ensuring adequacy will be an easier proposition if load serving entities adequately account for risk in their integrated resource plans. The Council will convene workshops on treatment of risk in integrated resource planning during 2005. State and local regulatory entities should require an accounting of risk in the integrated resource plans they oversee. States should consider legislation to require that all utilities that are responsible for developing their own resource portfolios write integrated resource plans on a periodic basis.

Transmission

A key element of the regional power system is transmission. If the power supplies that are recommended in this power plan are to be realized, additional requirements will be placed on the transmission system. It is not clear that we are presently organized to plan, expand, operate, and manage the regional transmission system as effectively and efficiently as necessary. There has been growing recognition of problems such as:

- Difficulty in managing unscheduled electricity flows over transmission lines leading to increased risks to electric system reliability;
- Lack of clear responsibility and incentives for planning and implementing transmission system expansion, resulting in inadequate transmission capacity;
- Inadequate consideration of non-construction alternatives to transmission;[6]
- Inability to effectively monitor the wholesale electricity market, identify market power abuse, or provide mitigation and accountability;
- Difficulty in reconciling available physical transmission capacity with capacity available on a contractual basis, resulting in the inefficient use of existing transmission and generation capacity, and limitations on access for new resources to the existing grid;
- Transaction and rate pancaking, i.e., contracting and paying for the fixed costs of multiple transmission segments on a volumetric basis to complete a power sale, resulting in inefficient utilization of generation; and
- Competitive advantage of control area operators over competing generation owners resulting in the inefficient use of generation, and a potential proliferation of control areas with greater operational complexity.

In response, there has been a “bottoms-up” regional effort through the Regional Representatives Group (RRG) of Grid West (Formerly RTO West) to address these problems in a more comprehensive, yet incremental, Northwest grid-wide approach. In addition to the actions already identified regarding better utilization of existing transmission capacity and planning for transmission enhancements, the following actions should be pursued:

> **ACTION: Regional interests should continue to work through the Grid West RRG process to address emerging transmission issues –** While success is not assured, the RRG’s regional proposal offers a framework for addressing these problems.
>
> **ACTION: Bonneville and other transmission providers should expand efforts to identify and implement non-construction alternatives to transmission expansion –** The Bonneville Power Administration has been carrying out an innovative effort to identify and implement non-construction alternatives to transmission expansion with positive results. This effort should be incorporated as a basic element of transmission planning.

Fish and Power

The Columbia River Basin hydroelectric system is a limited resource that is unable to completely satisfy the demands of all users under all circumstances. Conflicts often arise that require policy decisions to allocate portions of this resource as equitably as possible. In particular, measures developed to aid fish and wildlife survival often diminish the generating capability of the hydroelectric system. Conversely, “optimizing”[7] the operation of the system to enhance power production can have detrimental effects on fish survival. Fish and power are inextricably linked

[6] Non-construction alternatives involve consideration of demand management, conservation, distributed generation, and so on to relieve transmission bottlenecks and defer construction of transmission upgrades.
[7] “Optimizing” here means that energy production is maximized, limited by other than fish and wildlife constraints, such as flood control, irrigation, navigation, etc.

in the Northwest. Outside of the Council, however, no clear process exists for integrated long-term planning for both fish and power.

> **ACTION: The Council will work with the federal agencies, state agencies, tribes, and others to broaden the focus of the forums created to address issues surrounding fish and wildlife operations, especially those related to long-term planning** – The forums should broaden their focus by including "expertise in both biological and power system issues," and by directly addressing longer-term planning concerns, not just weekly and in-season issues.

Future Role of the Bonneville Power Administration in Power Supply

On at least two occasions over the last decade, the Bonneville Power Administration has found itself financially and, as a consequence, politically vulnerable. Bonneville's financial vulnerability arises in part from its dependence on a highly variable hydroelectric base and the effects of a sometimes very volatile wholesale power market. Another source of vulnerability arises from the uncertainty created by the nature of the relationship between Bonneville and many of its customers, and how Bonneville has historically chosen to implement its obligations. These vulnerabilities are exacerbated by Bonneville's high fixed costs for its debt on the Federal Columbia River Power System and the three nuclear plants that were undertaken, with Bonneville backing, by the Washington Public Power Supply System, now Energy Northwest.[8] At times, these vulnerabilities can cause Bonneville to incur high costs that must be passed on to customers and ultimately to the region's consumers. If those costs are not passed on to customers, Bonneville risks being unable to make its payments to the U.S. Treasury. Rate increases cause economic hardship in the region; not making a Treasury payment risks a political backlash from outside the region that could cause the Northwest to lose the long-term benefits of power from the federal system.

The Council and others in the region have been working to develop alternative ways in which Bonneville can meet the requirements of the Northwest Power Act with greater financial stability, while reducing the uncertainty surrounding responsibility for serving load growth and preserving the benefits of the federal system. The Council has recommended that Bonneville implement these changes through new long-term contracts to be offered by 2007. The key elements of those recommendations are:

> **ACTION: Bonneville should sell electricity from the existing Federal Columbia River Power System to eligible customers at its embedded cost. Customers that request more power than Bonneville can provide from the existing federal system would pay the additional cost of providing that service –** This would clarify who would exercise responsibility for resource development; it would result in an equitable distribution of the costs of growth; it would provide clear signals of the cost of new resources, and it would prevent the value of the existing federal system from being diluted by the higher costs of new resources. This should be established in Bonneville policy and implemented through new long-term (preferably 20-year) contracts and compatible rate structures. This should be accomplished well in advance of the expiration of the current contracts in 2011.

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[8] Of the three plants, only one, Columbia Generating Station, is operating. The other two were terminated before construction was complete. However, Bonneville still has responsibility for paying off the debt incurred during construction.

ACTION: Bonneville and the region's utilities should work to resolve the issue of benefits for the residential and small-farm customers of investor-owned utilities (IOUs) for a significant period – The necessary characteristics of a settlement can be defined. A settlement must be equitable to all participants, it must provide certainty, it must be transparent, and it must not be subject to manipulation. This must be accomplished in time to support the offering of new contracts in 2007.

ACTION: Bonneville and the region's utilities should continue to acquire the cost-effective conservation and renewable resources identified in the Council's power plans -- Bonneville should employ mechanisms similar to the current Conservation and Renewables Discount (C&RD) program and provide essential support activities to encourage and facilitate utility action. Bonneville's role will be substantially reduced to the extent that customers can meet these objectives. But if necessary, Bonneville must be prepared to provide a backstop mechanism to ensure that the conservation objectives are met.

ACTION: Bonneville should continue to fulfill its obligations for fish and wildlife -- Those obligations will be determined in a manner consistent with the requirements of the Northwest Power Act and the Council's Columbia River Basin Fish and Wildlife Program, and are not affected by the recommended changes in Bonneville's role.

ACTION: Bonneville should develop a policy to implement long-term contracts and compatible rate structures, and should include the process and time schedule for resolving the issues in the Council's recommendations on the Future Role of the Bonneville Power Administration in Regional Power Supply, Council Document 2004-5. Bonneville policy must be responsive to concerns among customer utilities that the scope of the policy will include sufficient process detail to guide utility decisions in long-term resource planning; to include provisions by which Bonneville intends to extend assurances of contract durability and enforcement in areas such as Bonneville cost control, dispute resolution, continuation of Bonneville's role in conservation and renewable resource acquisition, allocation of the existing federal power system, and fish and wildlife mitigation.

ACTION: Bonneville should consider alternative policy processes, if necessary. Should activities undertaken in response to future Bonneville policy prove inadequate to meet the schedule established for resolution of regional issues leading to development, offering, and acceptance of new contracts by October 2007, then alternative means of resolving outstanding issues should be considered. Before considering legislation as an alternative, the Council recommends that Bonneville and the Council work jointly to determine if substantive rulemaking under the Federal Administrative Procedure Act can be a vehicle for issue resolution.

Monitor "key indicators" that could signal changes in plans

Load-Resource Situation

The power plan performs well for the majority of the futures examined. However, were the region to sustain high rates of load growth near upper extremes of the forecast growth rates during the first several years of the planning period, or should there be a significant loss of projected resources, the recommended plan could incur high costs if strictly adhered to. Obviously it will be necessary to track load growth and resource development closely along with market conditions to ensure an adequate system and to accelerate development plans, if necessary.

> **ACTION: The Council will monitor and periodically report on the regional load-resource situation and indicate whether there is a need to accelerate or slow resource development activities.**

Conservation not developed at recommended pace

The plan includes aggressive development of conservation at an average rate for 140 average megawatts per year during the five year Action Plan period. While the region has developed conservation at this rate at some times during the past, the rate of acquisition has frequently been less – 50 average megawatts. If conservation were to be developed at this rate, the average cost to the region over the planning period could be $2.5 billion more and the risk $3.5 billion greater. These cost and risk increases are the result of two factors: the need to accelerate the development of more expensive generation, and the exposure of additional load to periods of higher market prices for electricity.

> **ACTION: The Council will monitor regional conservation development --** If conservation is not being developed at the recommended levels, efforts should be made to accelerate conservation development. If that cannot be achieved, the alternative will be to accelerate the development of additional, more expensive, generating projects.

Climate change science and policy

Both coal-fired power plants and gas-fired combustion turbines are present in this power plan. However, in scenarios in which significant penalties on carbon emissions are implemented relatively early in the planning period, these resource are not developed. If this were to appear likely, the plan should be reconsidered. Conversely if there are significant reductions in the costs of carbon offsets or improvements in efficiency and emissions characteristics of generation using carbon-based fuels, these technologies could play a larger role.

> **ACTION: The Council will monitor climate change science and policy --** If the uncertainty surrounding climate change science and policy is reduced, and with it the likelihood of future carbon emissions control requirements, the role of carbon-fueled generation will be re-examined. Similarly, if there are advances in high efficiency coal generation technology, carbon sequestration or the availability and cost of carbon offsets, the role of carbon based fuel generation should be re-examined.

Demand response not available at level estimated

If demand response is not available or is not developed at the levels and costs estimated, the result will be a somewhat more costly and risky portfolio and could require that additional combined and/or single cycle generation be developed.

> **ACTION: The Council will monitor the development of the demand response resource.**

New Technologies

In addition to coal gasification, the following technologies have the potential to supply a major portion of regional load and in certain circumstances, could be attractive development opportunities late in the planning period. They have not been included in the portfolio risk analysis and resource development recommendations because of significant impediments to their development. They are difficult to consider "available" as defined by the Northwest Power Act. Because of the potential attractiveness of these resources under plausible future conditions, it is important to understand their potential role, key impediments to their development and regional actions that could help resolve these impediments.

ACTION: The Council will monitor the development of the following technologies for indications that they should be included in updates of the power plan.

Solar Photovoltaics -- Conversion of sunlight to electricity using photovoltaic technology is a well-understood and commercially established process, but its costs are far too high for economic bulk electricity production. Solar electricity production using photovoltaic (or solar thermal) technology would be particularly attractive with sustained high natural gas prices, wind at higher cost and lower availability than forecast, and an aggressive greenhouse gas control policy. An additional factor favoring solar generation would be the failure to develop the economic means of reducing the carbon dioxide output associated with coal-based generation.

Preliminary Council studies suggest that bulk electricity production from solar photovoltaics could be attractive beginning in the 2015-20 period if costs continue to decline at rates observed during the 1990s. However, photovoltaic cost reduction has been stagnant in recent years, and technical breakthroughs may be required to achieve the cost levels required for large-scale deployment. Because of the prospects of a continuing high differential between photovoltaic electricity costs and market value, there appears little that the region can afford to do to effect significant cost reductions for this global product beyond seeking out near-economic niche applications and to encourage federal research. The most economic large-scale solar generation sites are far from most regional load. Development will require the ability to develop additional bulk transmission capacity and would also benefit from low-cost/short-term energy storage technologies.

Advanced Nuclear Plants -- Advanced nuclear plants would incorporate passive safety systems and standardized modular components for increased factory fabrication. These features are expected to result in improved safety, reduced cost, and greater reliability. Though preliminary engineering of these designs is complete, construction and successful operation of several demonstration projects is required before the technology can be considered to be commercial. Demonstration plant development lead times are such that the technology is unlikely to be available for commercial construction until about 2015, suggesting commercial operation around 2020. In addition, establishment of a fully operational system for spent nuclear fuel disposal is a likely prerequisite to general public acceptance of new nuclear development.

Nuclear plants could be attractive under these conditions, as well as under sustained high natural gas prices, limited wind, and an aggressive greenhouse gas control policy. Additional factors favoring nuclear generation would be the failure to develop the economic means of reducing the carbon dioxide output associated with coal-based generation and the inability to expand long-distance transmission capability. The nature of the actions required to commercialize advanced nuclear technology do not lend themselves to solution by the region, other than through the support of federal activities addressing these issues.

Implementing the Plan: Sections 4(c)(9), 4(i) and 4(j) of the Act – The resource acquisitions of the Bonneville Power Administration are to be consistent with the Council's plan. It is the responsibility of the Council to ensure that they are.

ACTION: The Administrator and other federal agencies, to the extent authorized by other provisions of law, shall furnish the Council all information requested by the Council as necessary for the performance of its functions, subject to such requirements of law concerning trade secrets and proprietary data as may be applicable. The Council intends to be vigorous in its review and tracking of Bonneville actions undertaken for consistency with the Plan and assumes this responsibility under provisions of the 1980 Pacific Northwest Electric Power Planning and Conservation Act with full recognition of the need for reciprocal cooperation between Bonneville and the Council.

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Northwest Power and Conservation Council

5^{th} Plan Executive Summary and Action Plan

Council Briefing

Sept 8, 2004

Overview

- Background
- Planning for uncertain future – Sources of uncertainty considered
- Resources for the Future – Resources considered
- Evaluating plans – approach used
- The Plan – Characteristics, choice of ***A Plan***, description
- Strategy for an Uncertain future
- Action Plan – agenda for action over next 5 years

Northwest Power and Conservation Council

“The Plan”

- Analysis produces lots of plans – each represent lowest cost for given risk
- General Observations
  - Significant conservation characteristic of all plans; failure to develop → much increased cost & risk
  - Demand response beneficial
  - Not major generation resource construction during action plan period (2005-2009)
  - Several plans include coal-fired generation with construction beginning as early as 2009
  - High gas prices defer gas-fired generation until late in planning period
  - Wind significant in most plans

Northwest Power and Conservation Council

Base Plan

- Low risk plan chosen
  - Risk measure doesn't capture all adverse effects of bad outcomes
  - Reduced price volatility
  - Improved reliability
  - Diverse portfolio

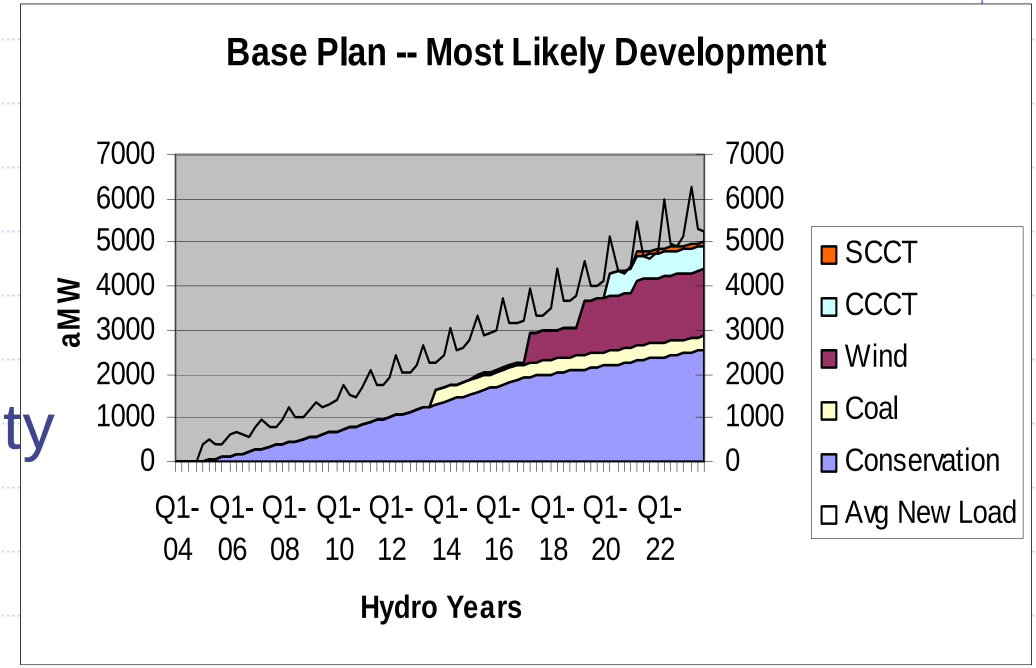

Figure ES-10

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Characteristics of Base Plan

- Conservation -- 130 → 150 aMW year over first 5 years
  - Reduce system cost $2 -- $2.5 billion compared to lower levels of conservation (out of $19 billion base)
  - Increase achievements 10 percent compared to 2001-2002
  - 5 year cost $1.35 Billion, slightly less than expenditures in 1992-1996
  - A significant challenge but several major NW utilities planning at that level

Characteristics (2)

- Develop 2000 MW of demand response over by end of planning period
  - Actual use modest but saves $100 million while reducing risk $500 million
- By 2009 be prepared to begin construction of 400 MW coal
  - Could require longer lead time transmission
- Wind plays large role somewhat later
  - Limited commercial scale development (50-100 MW cap/year) soon to verify cost and performance
- Gas fired generation last 7-8 years

Northwest Power and Conservation Council

Action Plan Strategy

- Develop resources now that reduce cost and risk
  – conservation, DR, lost-op renewables and cogeneration
- Prepare to construct additional generating resources – siting, permitting, TX siting and perhaps construction; confirming planning estimates for wind
- Confirm availability, cost of promising resources – integrated coal gasification, alberta oil sands cogen
- Establish policy framework to ensure ability to develop – resource adequacy, transmission management
- Monitor key indicators

Action Plan – Develop resources now...Conservation

- Focus on "Lost Opportunity" conservation
  - New initiatives are needed at all levels
  - Programs, codes and standards
  - Ramp up to 85% penetration in 12 years
    - 10 to 30 aMW/year 2005 through 2009, medium growth
- Significant acquisition of "Discretionary" conservation
  - Return to acquisition levels of early 1993-1996
  - Utility & regional programs, market transformation
  - Target 120 aMW/year next five years

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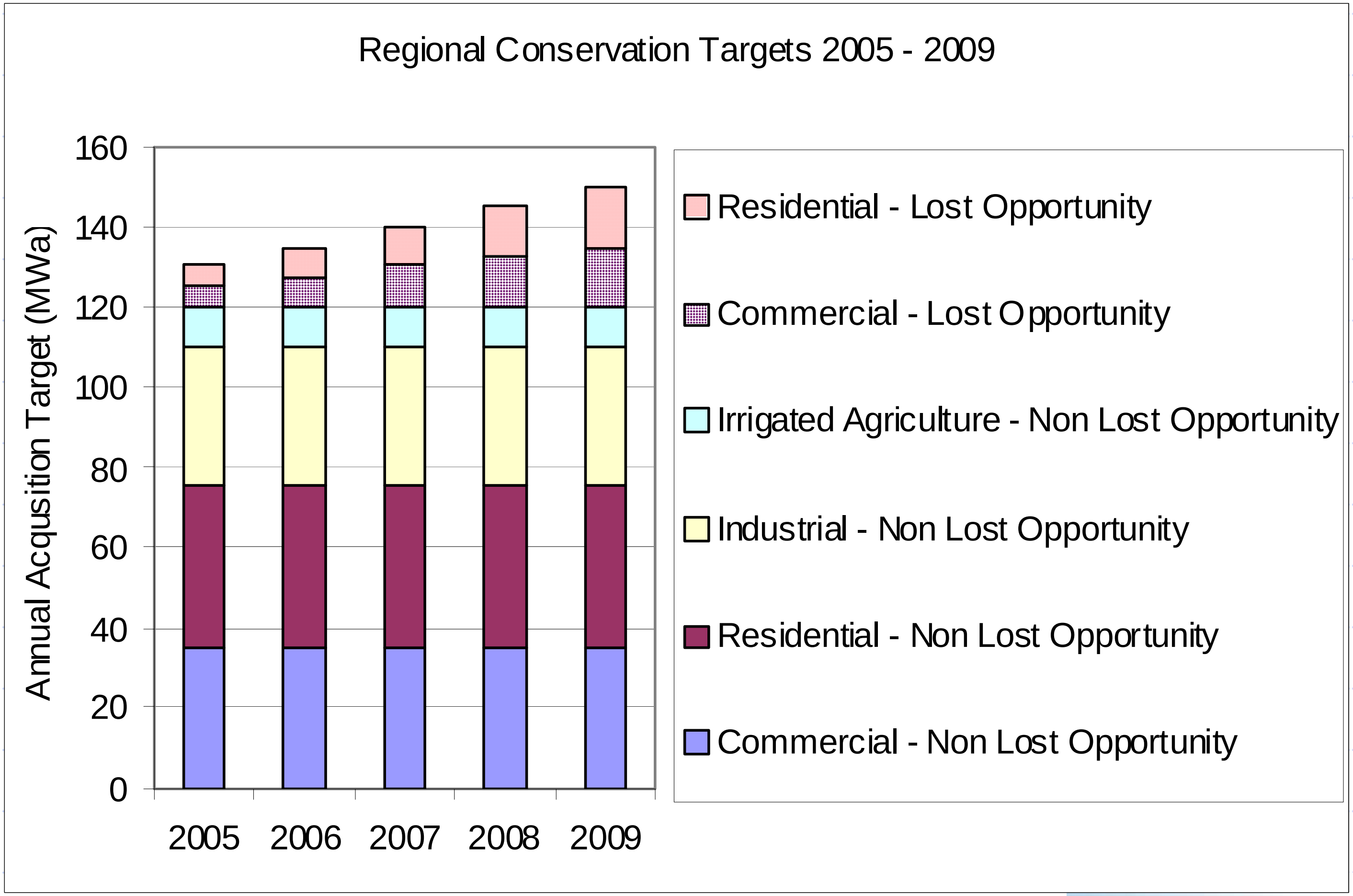
Action Plan – Conservation Targets



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Action Plan -- Conservation (2)

- A mix of mechanisms will be needed
  - Local utility, SBC Administrator & BPA programs
  - Market transformation
  - Codes and standards
  - Regional programs and coordination
- Develop a strategic conservation plan
  - Identify who does what by when
  - Council convenes forum
  - Produce plan in one year

Northwest Power and Conservation Council

Action Plan -- Conservation (3)

Elements of Strategic Conservation Plan

- Aggressive utility action is needed
  - Market and consumer actions insufficient
  - Modest increase targets & budgets over recent levels
- BPA can play a key role
  - Plan should define BPA role & actions
  - Structure of BPA conservation programs & funding
- Codes & Standards
  - States should adopt high priority appliance/ equipment standards where not pre-empted
  - Update state code to incorporate model standards for new buildings
  - Improve federal appliance standards

Action Plan -- Conservation (4)

Elements of Strategic Conservation Plan (cont.)

- Increase budget for market transformation
  - New initiatives & technologies
  - Codes & standards support
  - Increase pace/scope of existing initiatives
  - From $20 million/year to $30-$35 million/year
- Regional investments in "infrastructure" needed
  - RD&D, evaluation, education & training, common specifications, some acquisition
  - Need budget of $5 to $10 million/year
  - Possible entities: Alliance, BPA, RTF, or create new one

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Action Plan -- Conservation (5)

- Track conservation accomplishments
  - Improve mechanisms for regional reporting
  - Reports to Council annually
- Address regulatory barriers to conservation
  - Incorporate “hedge” value in IRPs
  - Strategies to mitigate lost-revenue impacts
  - Consider financing conservation investments
  - Evaluate System Benefits Charge (SBC) as alternative mechanism
  - Avoid conservation disincentives in the design of BPA allocation

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Action Plan – Develop resources now...Demand Response

- Expand and refine existing programs
- Develop cost-effectiveness methodology for DR
- Incorporate in Integrated Resource Plans
- Evaluate cost-effectiveness of improved metering and communications technology; monitor emerging technologies
- Explore how to make pricing mechanisms more acceptable
- Permit DR to participate in ancillary services markets

Action Plan – Develop resources now...Lost Op Renewable and CHP

- Opportunities to develop renewable and/or cogeneration projects – as much a a few hundred megawatts
- Driven by needs not related to power generation
  - Waste disposal
  - Equipment upgrading
  - New industrial or commercial development

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Action Plan – Recommendations
Lost Op Renewable and CHP

- Facilitate development of lost ops
  - Identify opportunities as they arise (IRP inventories, “open windows” for proposals, etc.)
  - Establish comprehensive procedures to evaluate
  - Remove utility disincentives to contract or invest
  - Uniform interconnection agreements
  - Acquire projects if cost-effective
- Utilities, commissions & developers

Action Plan -Prepare to construct generating resources

- Establish inventory of ready-to-develop projects
  - Coal: 400 MW by 2009
- What does this mean?
  - Projects sited & fully permitted
  - Preliminary engineering complete
  - Needed transmission and means of securing identified
- Utilities, permitting agencies & developers

Action Plan -Recommendations Prepare to construct...

- Resolve uncertainties re: cost & availability of large-scale wind development
  - One commercial-scale (25–100 MW) pilot project per year
    - Assess resource area potential
    - Establish long-term monitoring station if not present
    - Monitor cost & performance trends
    - Assess cost of shaping; benefits of geographic diversity
    - Assess capacity value
    - Assess issues and secure permits for larger resource area
  - Leverage planned utility & SBC acquisitions

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Action Plan – Confirm availability and cost of promising resources

- Promising, yet not fully "available"
  - Oil sands cogen – transmission
  - Coal gasification – warrantees & financing
  - Carbon sequestration – instrumentation & monitoring, suitability of PNW formations
  - Advanced energy storage – development & demonstration
- What to do??
  - Support federal efforts
  - Regional opportunities
  - Encourage state-of-the-art technologies

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Action Plan – Establish policy framework …

- Resource Adequacy
  - Establish West-wide reporting standards
  - Carry out process to establish voluntary standards
    - Appropriate for NW, compatible with West
  - Improve consideration of risk in IRP

Action Plan – Establish policy framework … (2)

- Transmission
  - High priority to work through Grid West RRG to address issues over next 2 years
    - Develop alternatives if necessary
  - BPA, other transmission providers expand efforts to implement non-construction alternatives
- Fish and power
  - Work with agencies to broaden focus of forums addressing power/fish & wildlife operations to include long-term planning

Action Plan – Establish policy framework … (3)

- Future role of Bonneville
  - Bonneville to sell power from existing system at cost; additional power at cost of acquiring
  - Resolve issue of benefits of residential and small farm customers of IOUs
  - Bonneville and utilities continue to acquire cost-effective conservation, renewables
  - Bonneville continue to fulfill F&W obligations
  - Develop policy to implement L.T. contracts and rate structures with schedule as called for in Council Recommendations
  - Bonneville consider alternative policy processes if necessary

Action Plan – Monitor key indicators …DW

- Monitor load-resource balance
- Monitor conservation development
- Wind availability and cost
- Monitor climate change science and policy
- DR not developed at level estimated
- Council review of Bonneville implementation
- Bonneville and Council review 6(c) policy

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Where to from here?

- Completed draft plan to you late next week
- Special meeting on the 22nd

Northwest Power and Conservation Council

Current Status of the Portfolio Analysis

Council Briefing

Sept 8, 2004

Overview

- Review of major changes
  - Treatment of IPPs
  - Gas Prices
  - CO_2 emissions penalties
  - Coal prices/Transmission
  - Conservation
- The "Base Case"
  - IPP Treatment
  - Conservation levels
  - Selection of Plan
- Sensitivities
  - CO_2
- Next steps

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Treatment of IPPs

- About 3000 aMW not currently committed long-term to regional load (mostly gas but includes 1100 aMW coal)
- Previous assumption –
  - IPPs in region; don't have firm TX access out
  - Capital costs sunk
  - Plants dispatch at **operating cost** (if needed)
  - **Region's consumers** get benefit of plants (Difference between market price and plant's operating cost when they operate)

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IPPs (cont.)

- Revised assumption –
  - IPPs still in region; don’t have firm TX access out
  - Capital costs sunk
  - Plants dispatch at **market price** when needed
  - **OWNERS** get benefit of plants (Difference between market price and plant’s operating cost when they operate)
  - Model may decide to build other plants to avoid costs of market purchases
- Reality – probably some combination of purchase of IPP generation (or L.T. contracts) and new builds.

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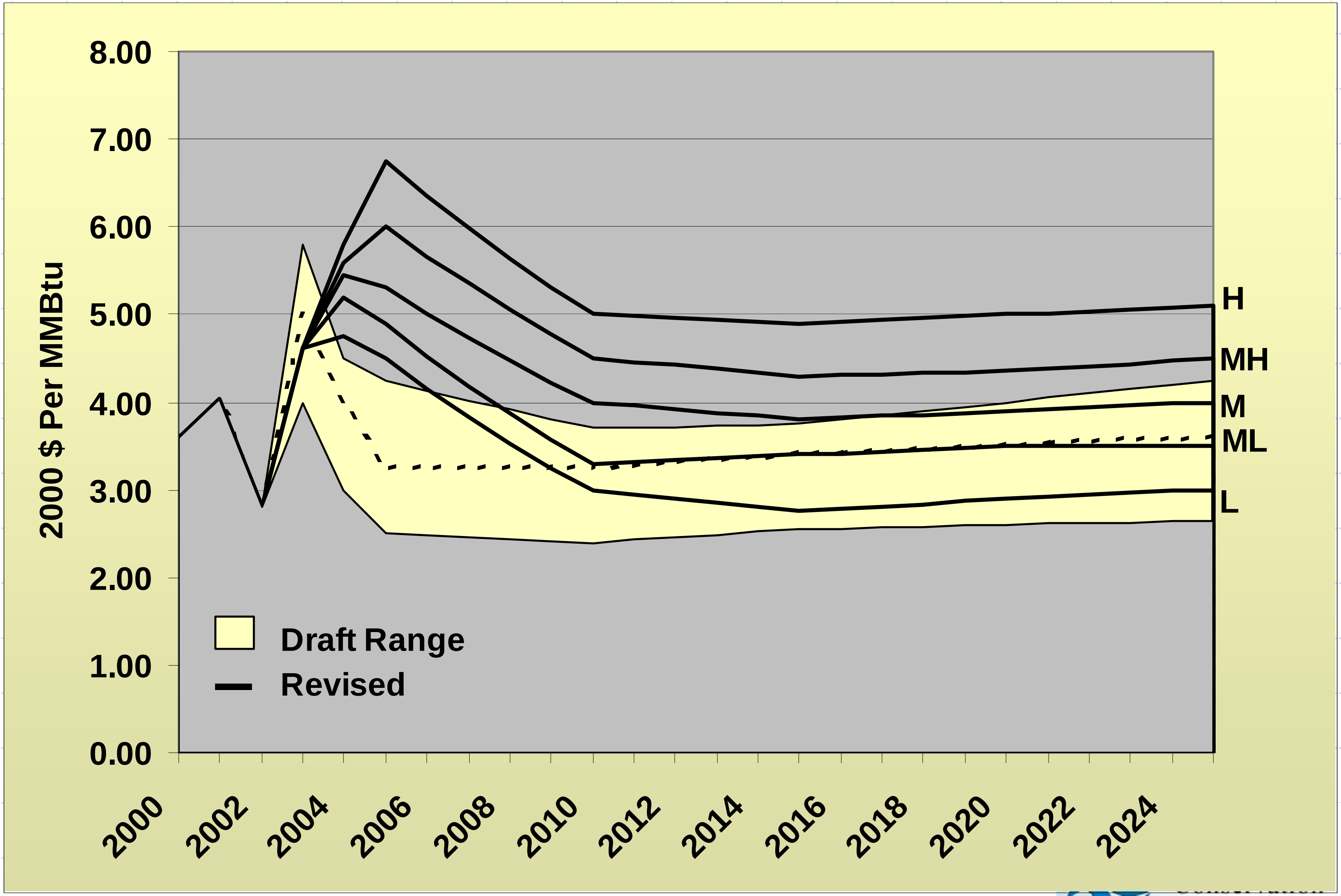
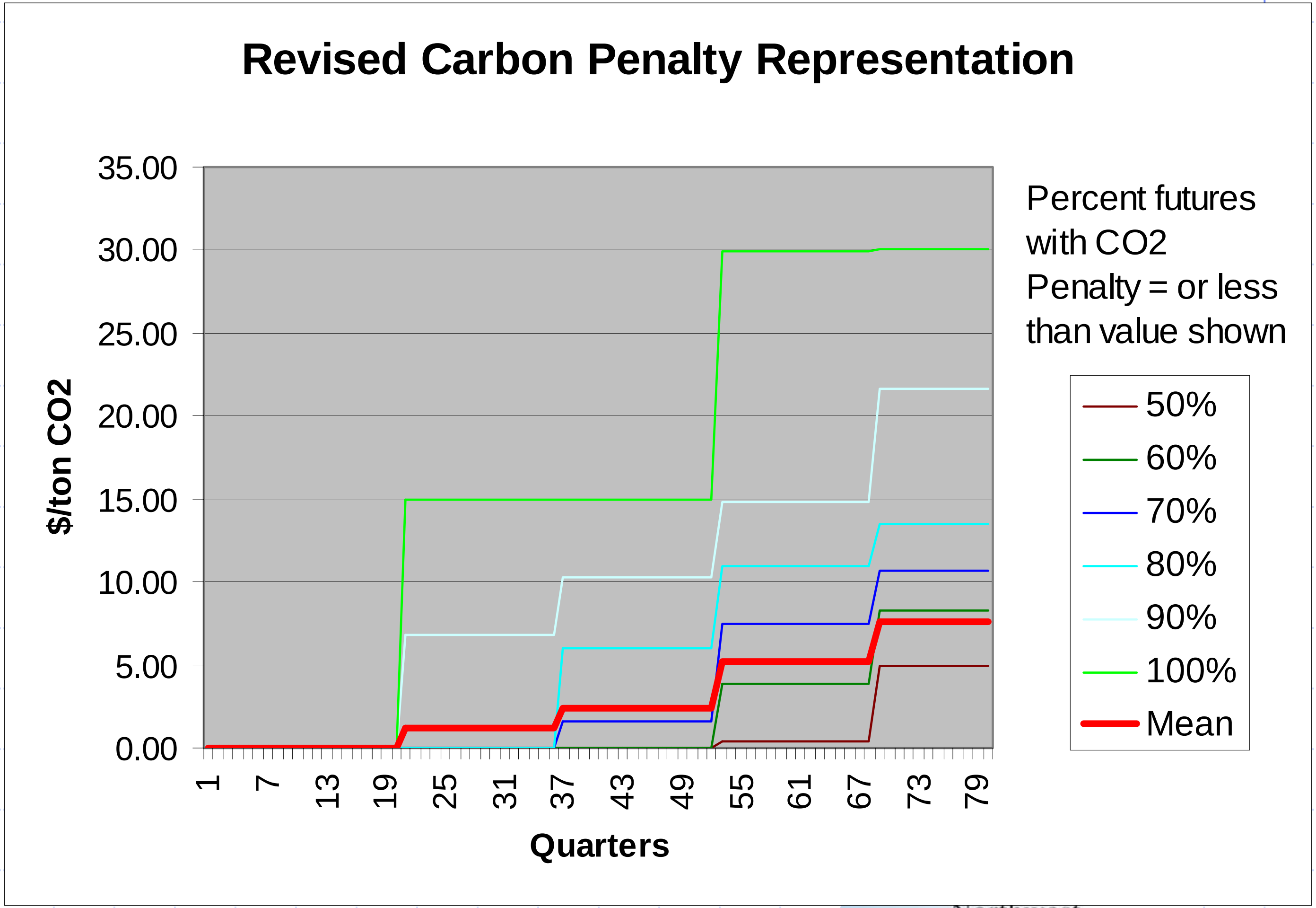
Revised gas prices



CO2 Penalties

- Phased in
- No penalty in 33% of futures
- Mean values less than values in utility IRPs



Coal prices/MT Transmission

- Reviewed our data
- Met with representatives of developer
- Conclusion – current data is an adequate representation of MT coal using unallocated TX capacity at embedded cost rates (up to 400 MW)
- Much controversy within transmission community re cost of transmission upgrades – NTAC study not available until the winter

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Conservation assumptions

- Revised supply curve for “discretionary” conservation
  - Added industrial conservation inadvertently left out (350 MW @ costs between 1-2 cents/kWhr)
  - Bundled measures to reflect implementation realities – you don’t get to do only the cheapest stuff first (costs up to 4.8 cents/kWhr, avg 2.1 cents/kWhr)
- Extended phase-in (how long before you can actually achieve potential potential) for lost opportunity conservation
  - 12 yrs instead of 6

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Effect of treatment of IPPs

Resource Development	Previous (Benefits to region)	Revised (Benefits to owners)
Coal-fired gen	No coal	400 MW Coal
CCCT and SCCT	None	Limited SCCT CCCT late in period
Wind	Lots in low risk plans, CY09	Lots in low risk plans, CY11
Conservation	About the same	About the same

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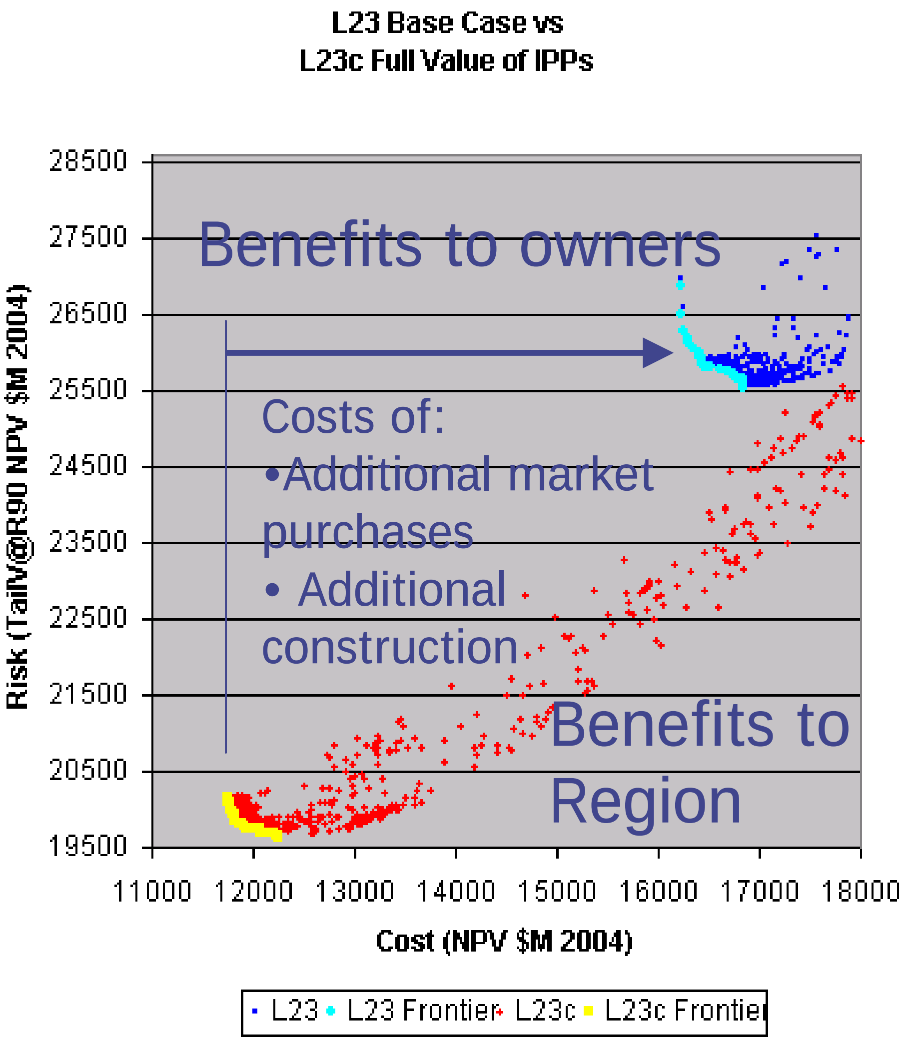
Significant value in the IPP resources

- Because benefits go to owners not consumers
- Region can secure some of the benefits by
  - Purchasing/contracting LT with IPPs; or
  - Building something
  - Both appear to be happening
- But at a cost
  - Difference in cost indication of value
- But lots of other factors enter into decision



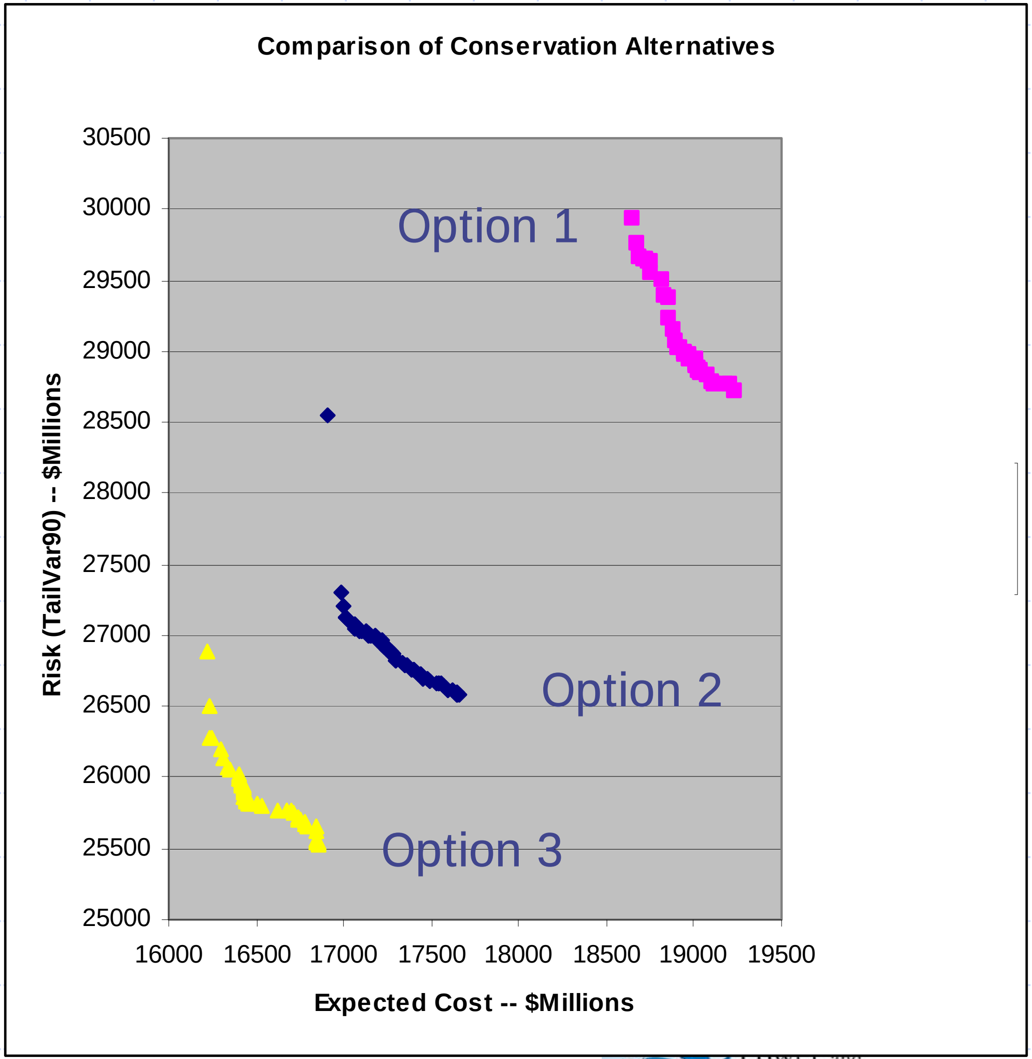
Conservation Council

Power committee recommendation

- Use assumption of IPPs not owned by regional entities as base
- Incorporate balanced discussion of issue in plan

Conservation Alternatives

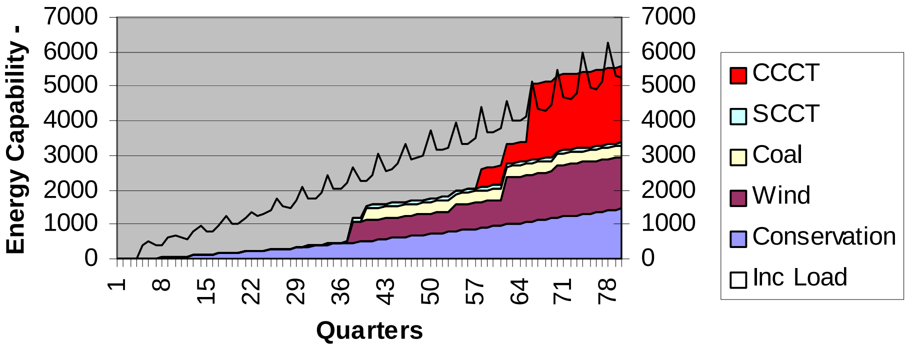
- Three alternatives
  - Option 1
    - Discret. – 10MW/Qrtr
    - LO – 20 year phase in
  - Option 2
    - Discret. – 20MW/Qrtr
    - LO – 12 yr phase in
  - Option 3
    - Discret. – 30MW/Qrtr
    - LO – 12 Yr phase in
- Significantly reduced cost and risk for more aggressive conservation



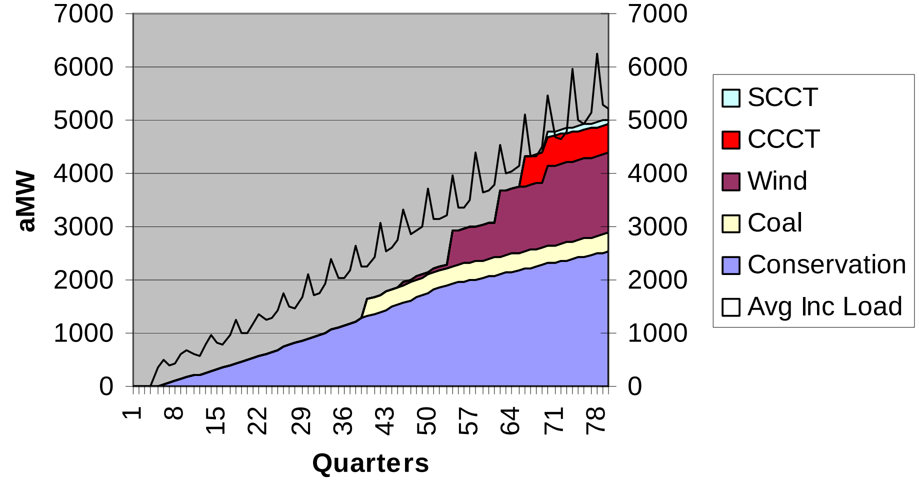
Power and Conservation Council

Different levels of conservation, different Portfolios

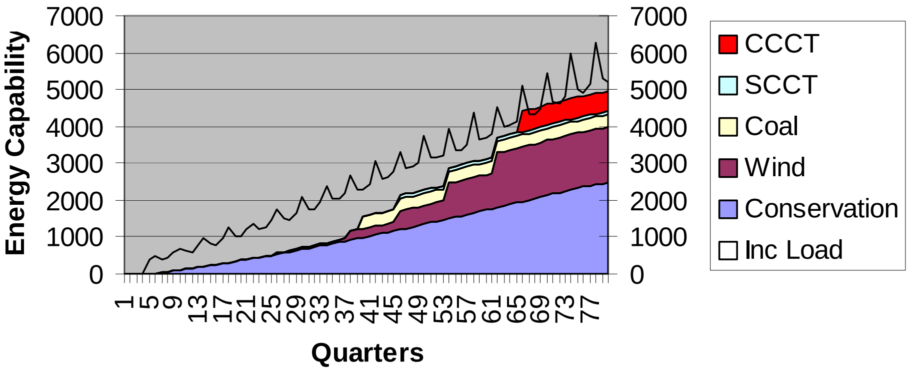
Option 1



Option 3



Option 2



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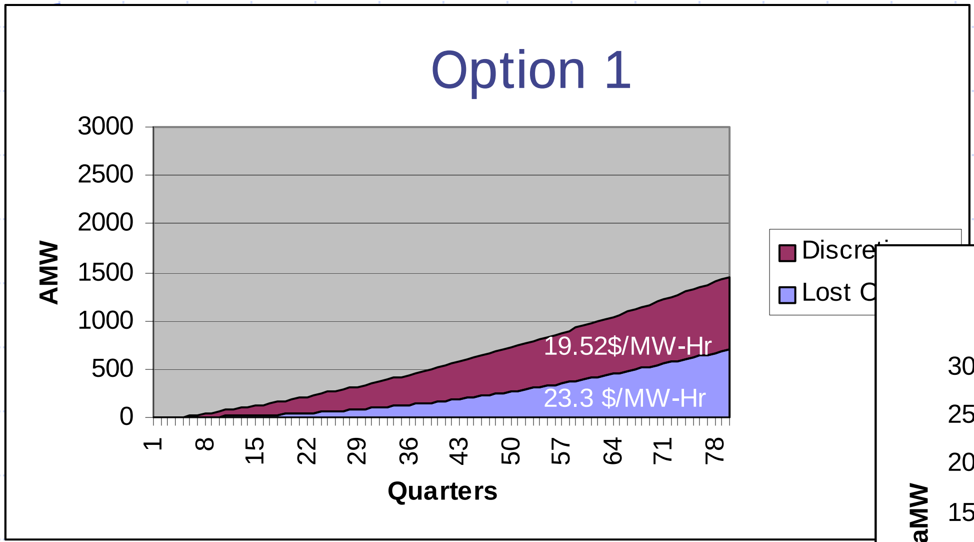
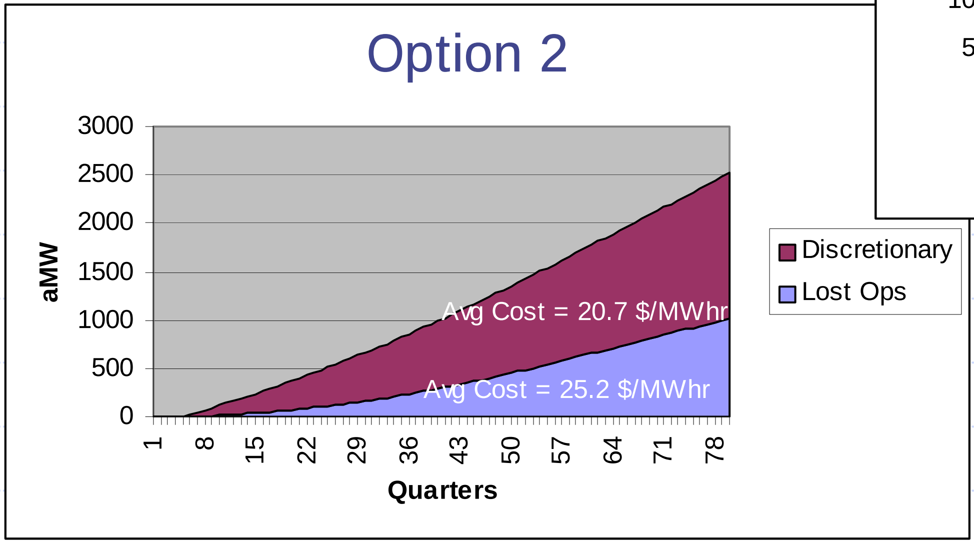
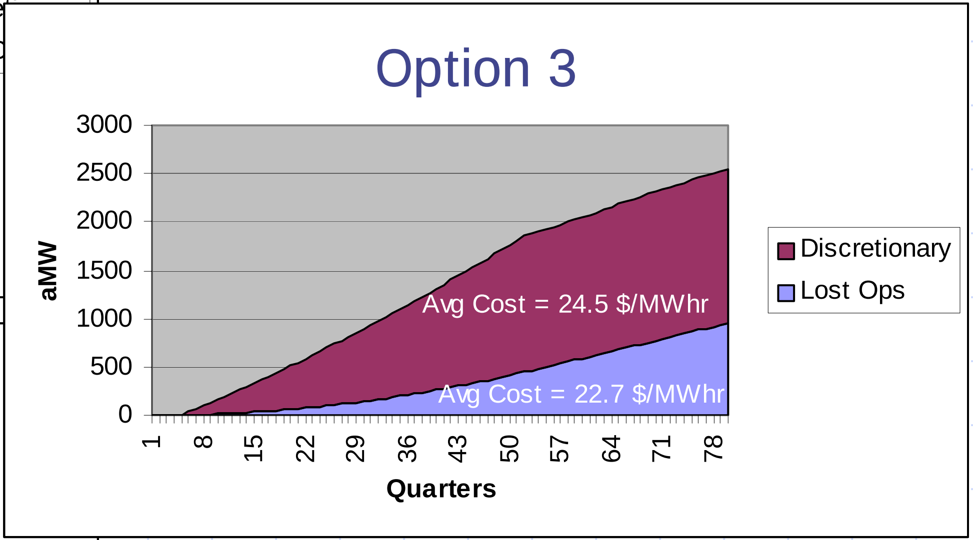
Conservation Development







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Power Committee Recommendation

- Option 3 conservation because
  - Substantial long-term benefit
  - We've done that much in the past
  - We have new capabilities that we didn't have then
  - Many of region's largest utilities are acquiring at about that level
- Additional discussion in action plan addressing barriers

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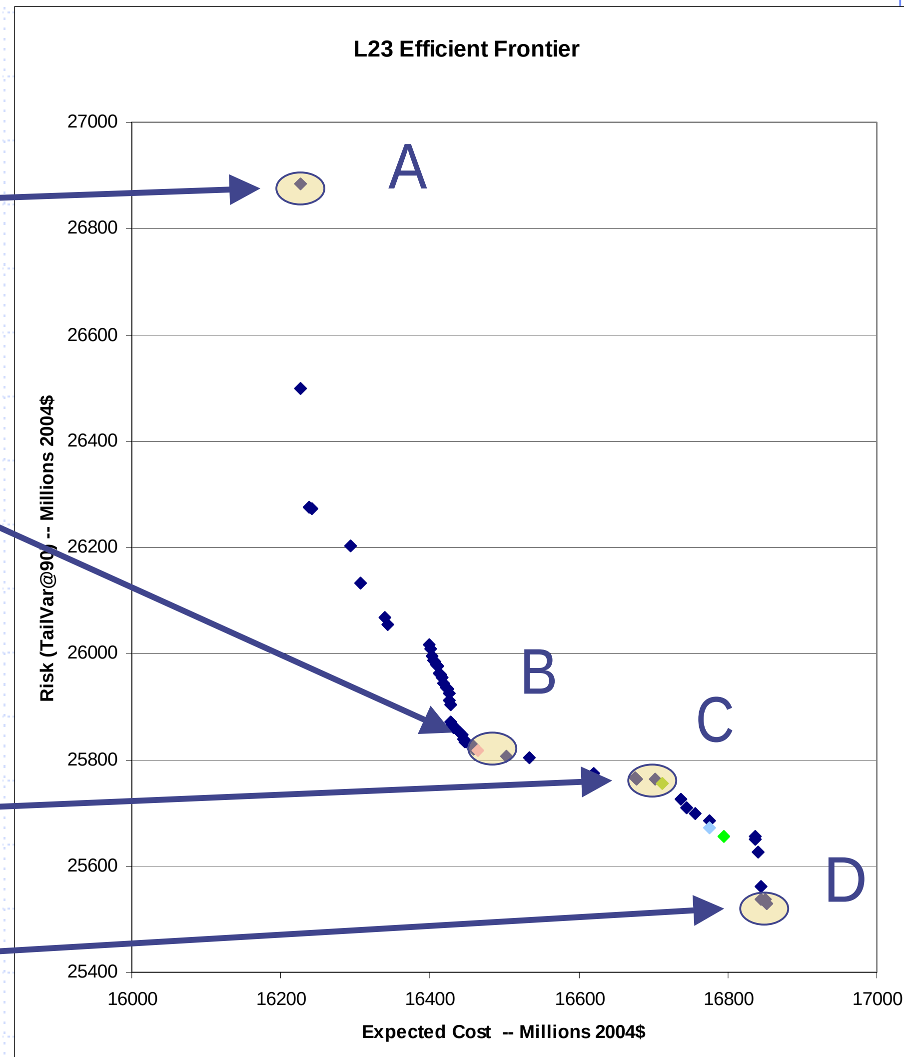
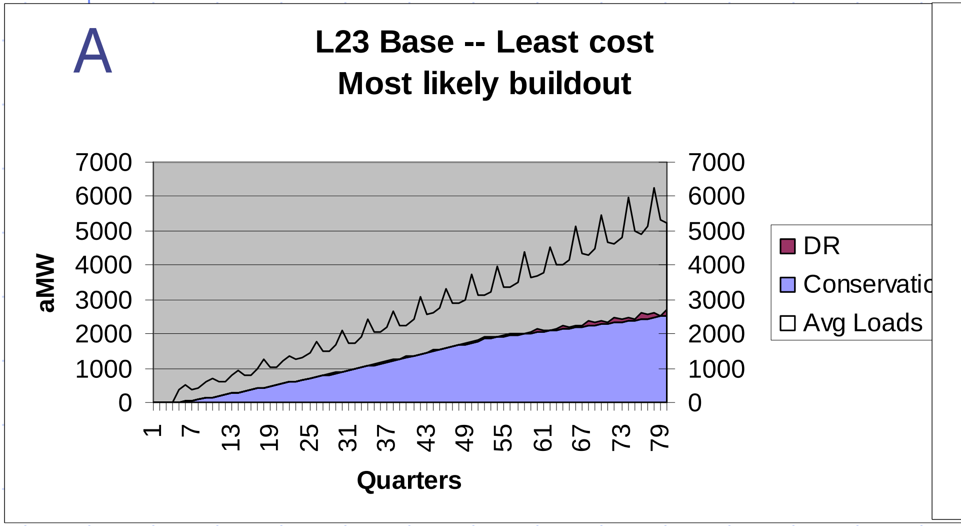
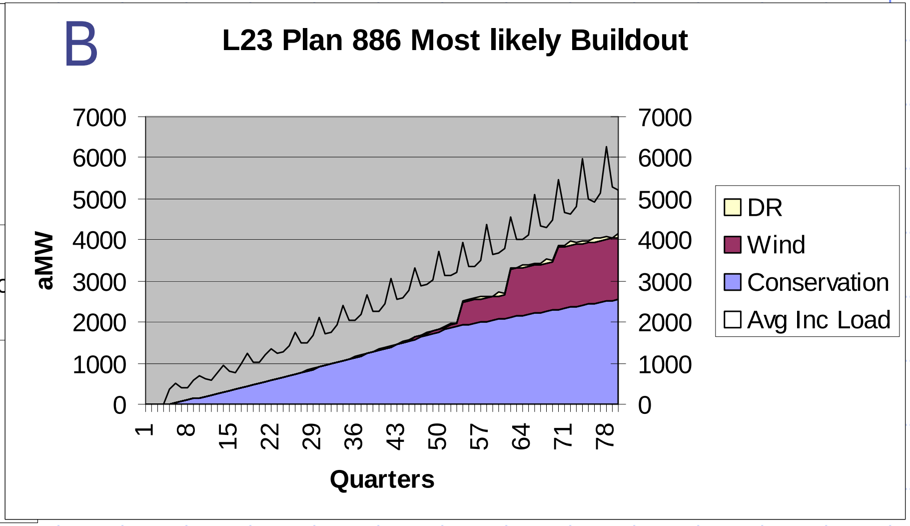
Choosing “A Plan”

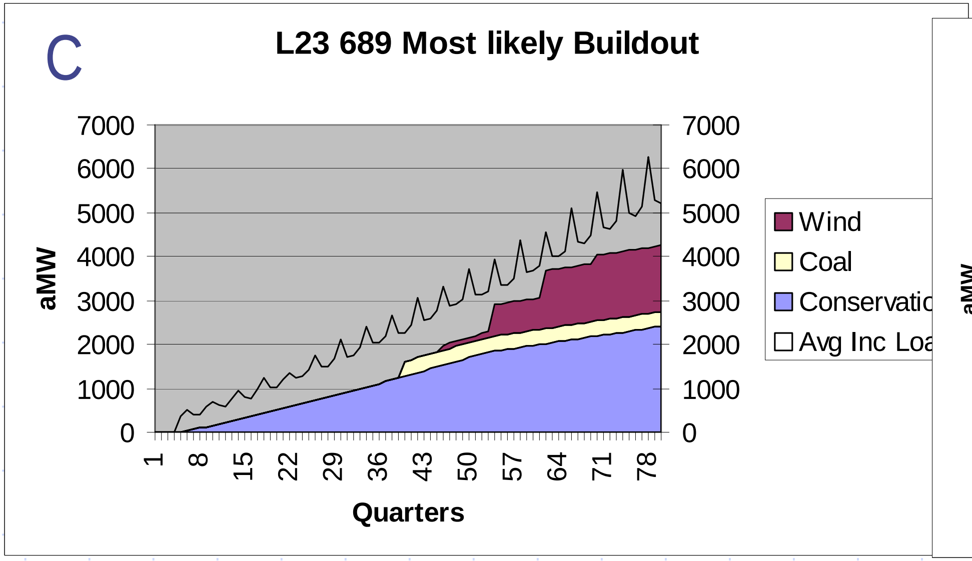
- Least Cost – Conservation + market
- Plan 886 --Conservation, wind+market
- Plan 689 -- Conservation, wind, coal+ market
- Least risk – Conservation, wind, coal, CCCT, SCCT + market

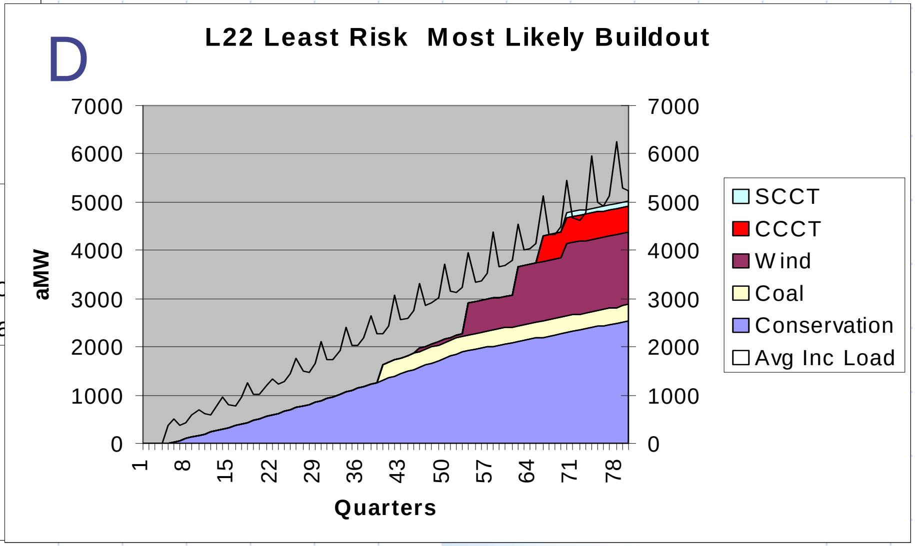


Comparison of Most Likely Build-outs









Action Plan doesn't change a lot from Least Cost to Least Risk

- For the five year Action Plan
  - Conservation
  - Confirm/Develop Demand Response Capability
  - Limited commercial scale wind (50-100 MW yr)
  - PLUS -- If plan chosen includes coal, pre-construction activities, possibly including transmission

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Considerations in choice of plan

- Relative weight of “average” costs versus costs at the extreme
  - Non-monetary effects of extremes
- Resource adequacy
- Effects on rate volatility

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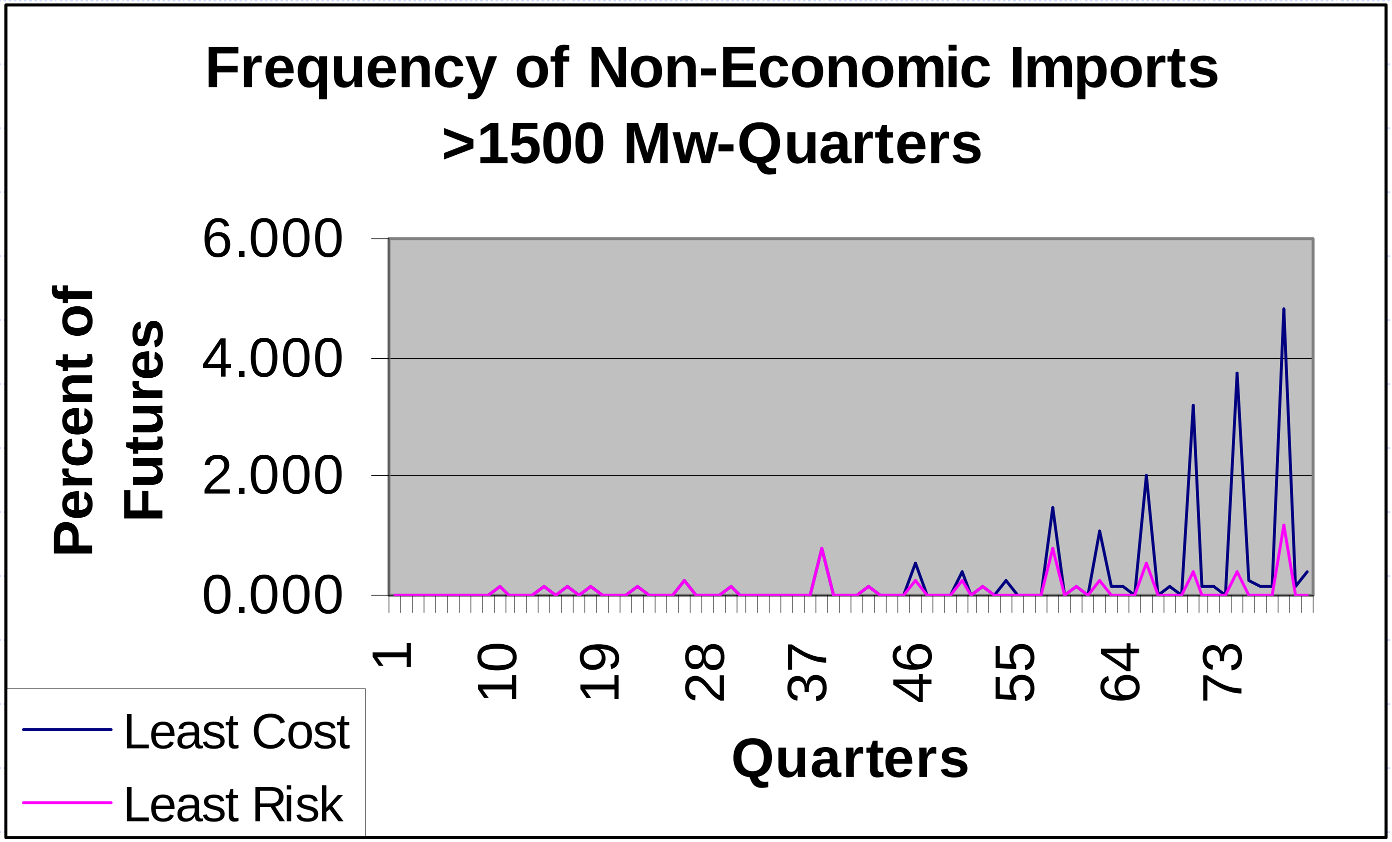
Comparative Adequacy



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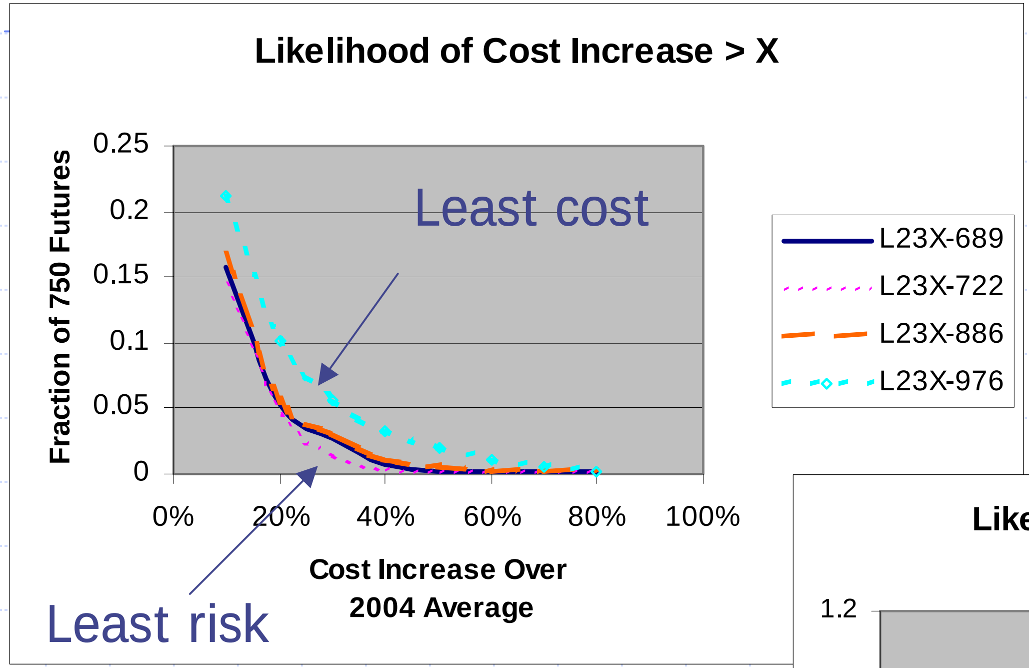
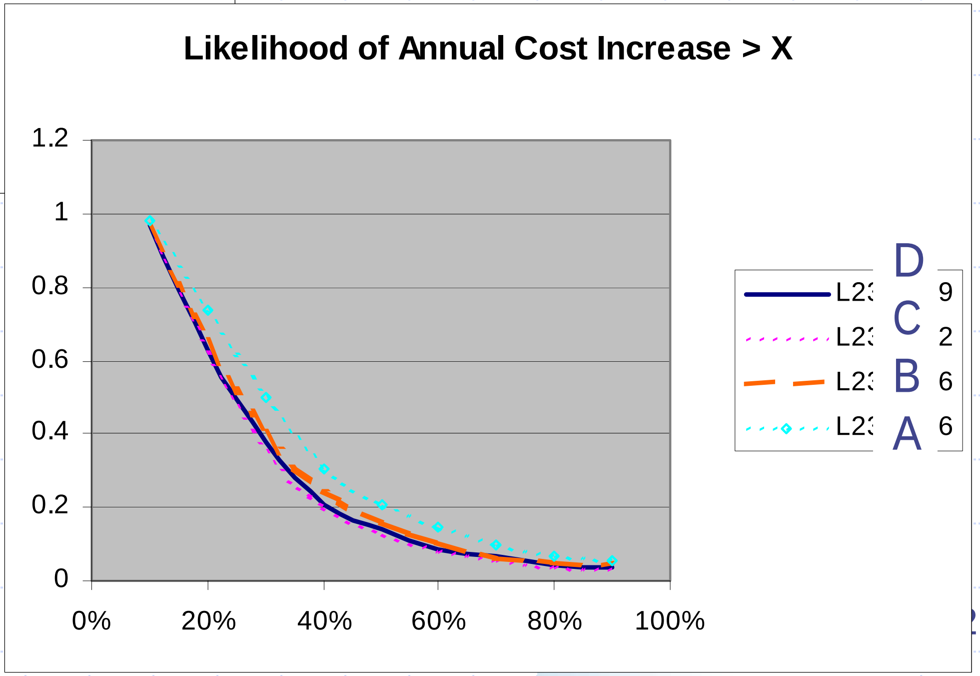
Retail Price Volatility





Power Committee Recommendation

- Use least risk plan as base

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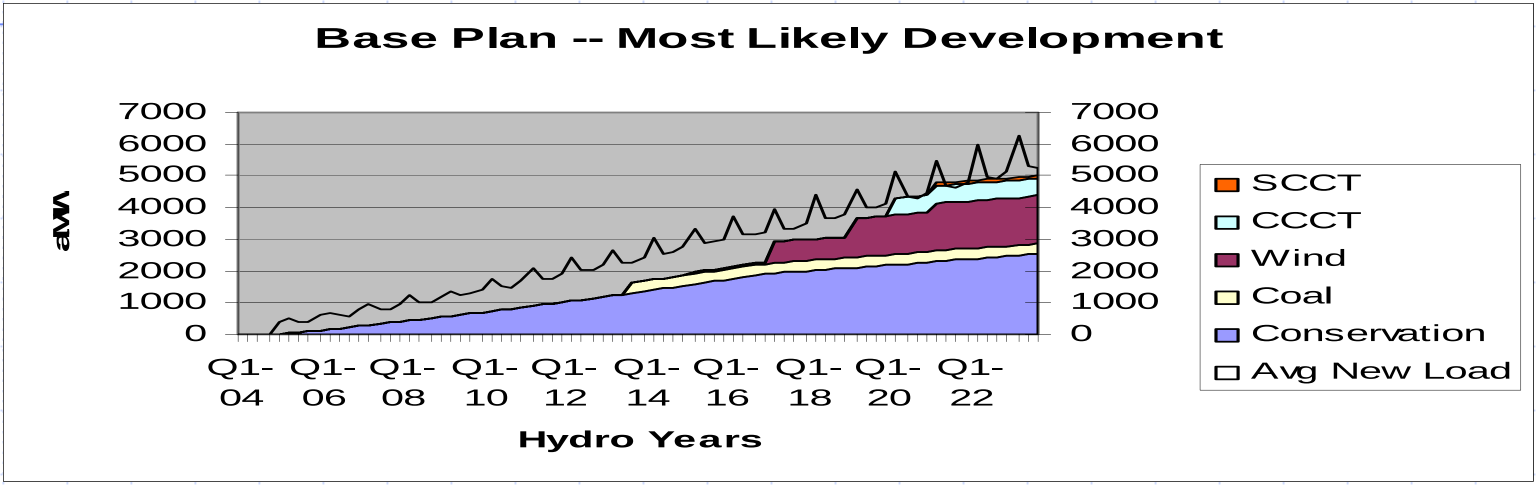
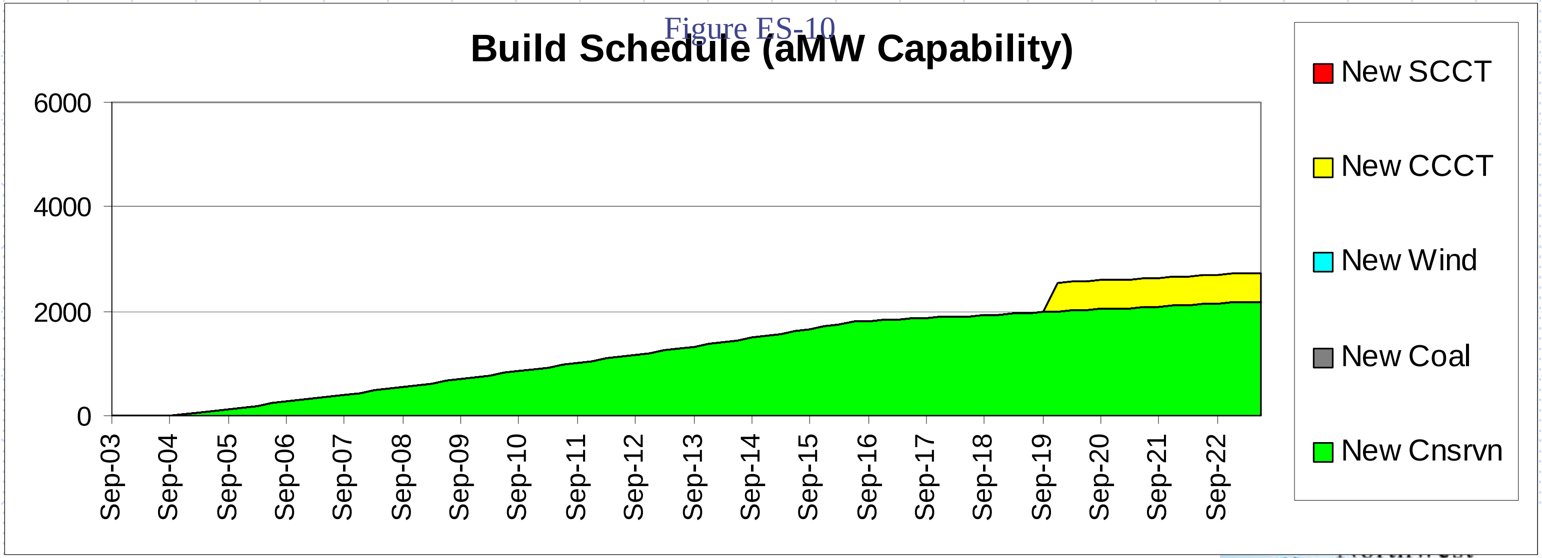
Selected scenarios





Low growth – Low Gas Prices

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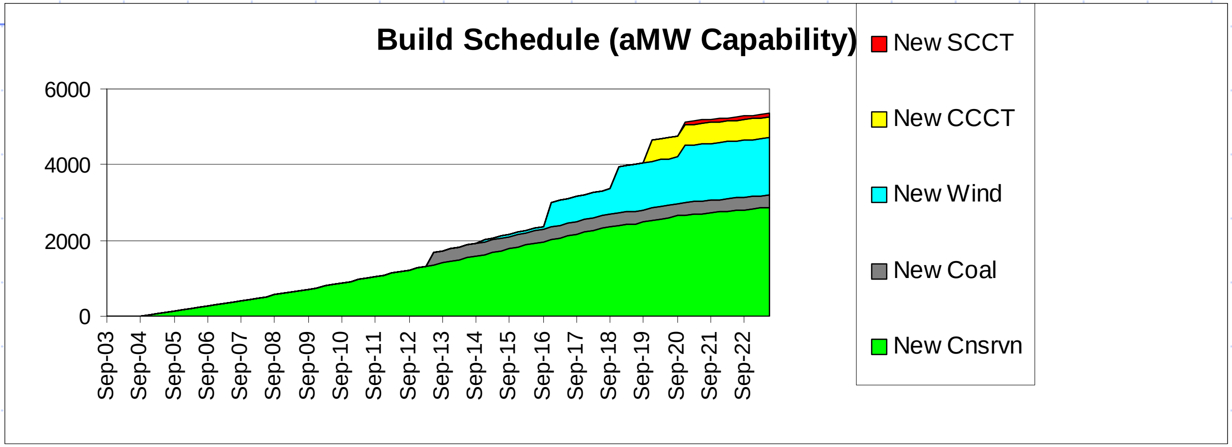
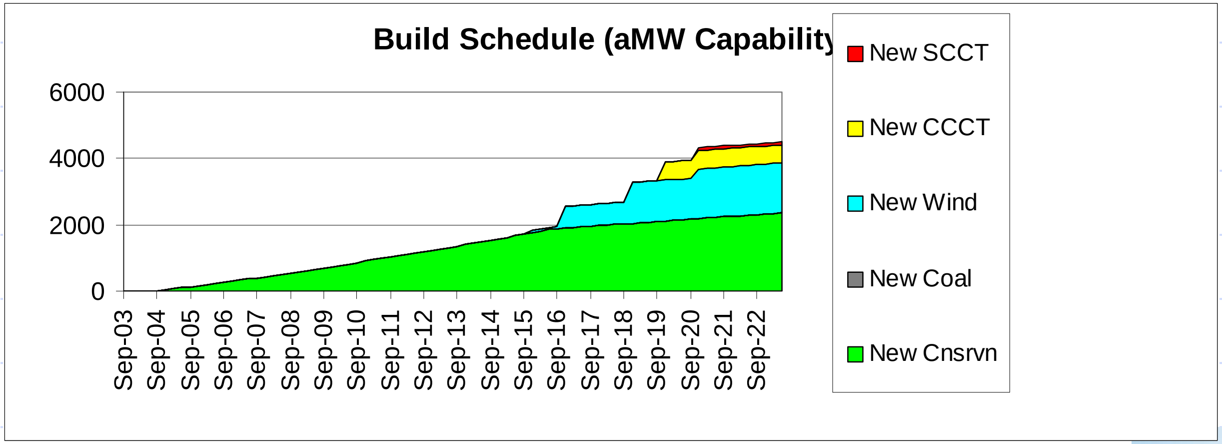
Selected Scenarios (2)



High Sustained Growth



Slow initial growth followed by relatively rapid growth

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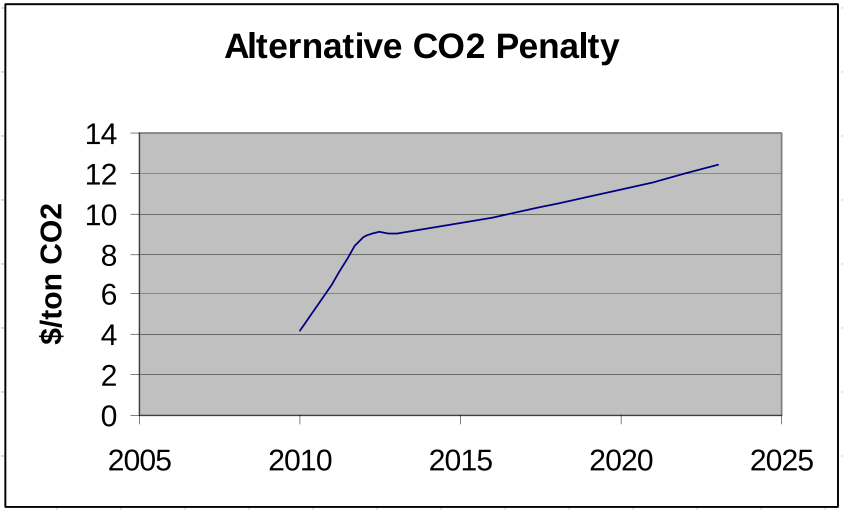
Sensitivities

- Test PacifiCorp CO2 assumptions – no significant effect
- No improvement in wind costs
- Coal gasification
- Alberta oil sands cogen
- Incentives for DSIs



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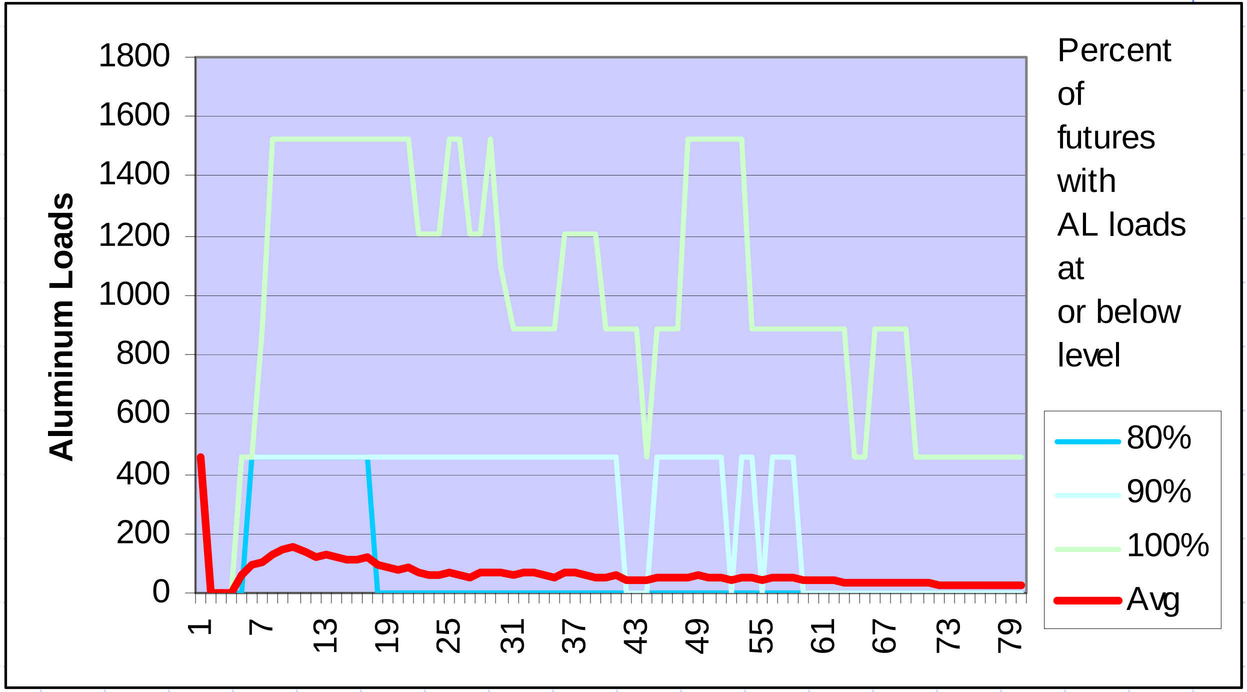
DSI Support

- Model incorporates no support ($ or MWs @ embedded cost rates) for DSIs
- Level of operation = f(market price, Al price), plants retired if out of operation 5 consecutive years



But Bonneville considering some level of support

- Assuming market prices = $40/MW-hr

Support	$1600 $/ton Al	$1500 $/ton Al
0	885 MW Al load	0 MW Al load
100 MW @ $7/MW-hr	885	428
200 MW @ $7/MW-hr	885	885
200 MW @ $15/ MW-hr	1202	885

Still subject to variation in price of electricity and aluminum

We can model some assumption about support

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