Northwest Power and Conservation Council

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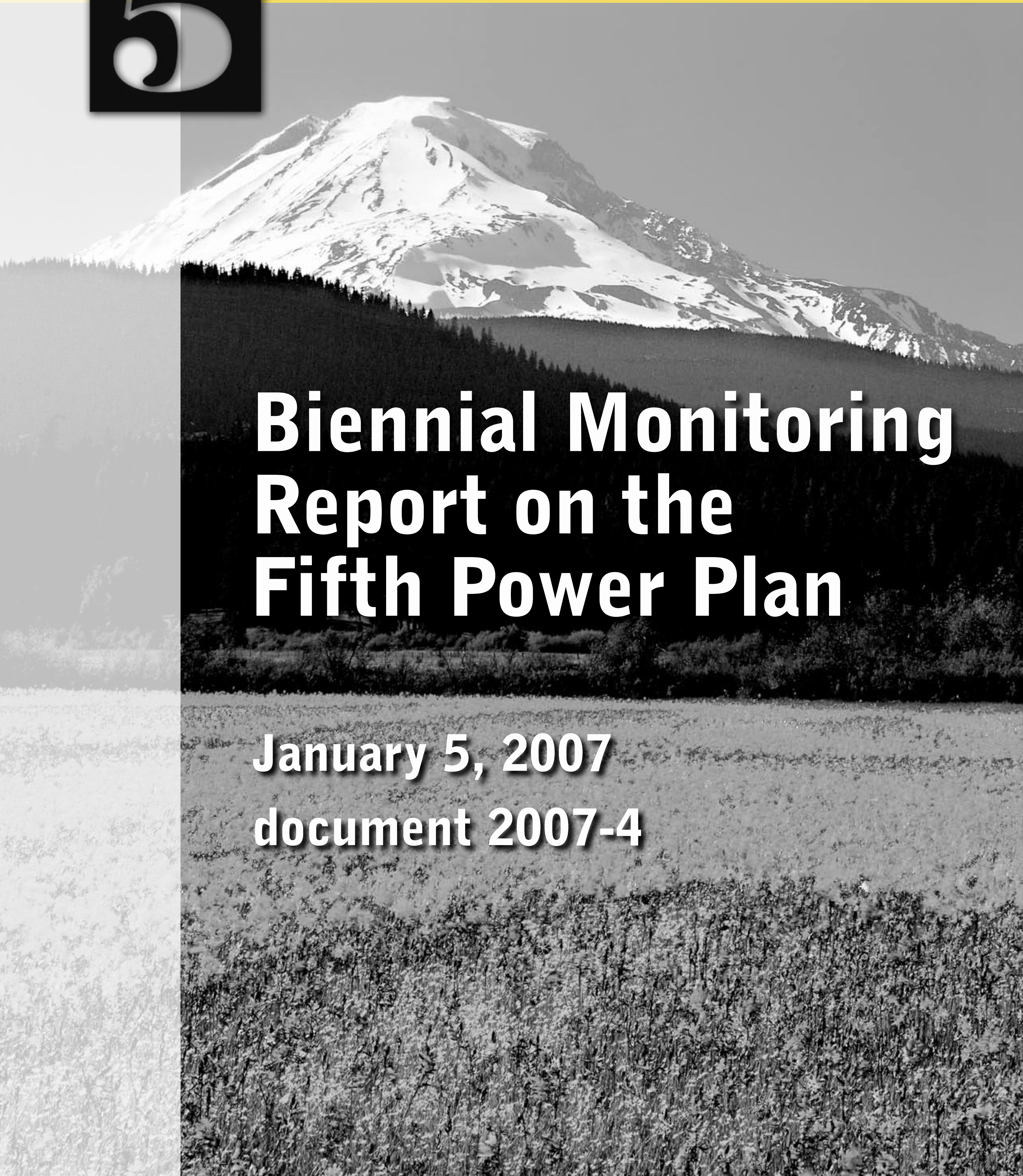

Biennial Monitoring Report on the Fifth Power Plan

January 5, 2007

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Introduction

Major Findings of the Fifth Power Plan

The Northwest Power and Conservation Council adopted its Fifth Power Plan in December of 2004. The plan broke new ground in its analysis of uncertainty and volatility, and their associated risks for future power costs. The key conclusions embodied in the Fifth Power Plan were that the region should acquire improved energy efficiency at an aggressive and sustained pace. The benefits of this strategy were both lower costs and lower risks.

A second conclusion of the plan was that wind energy is potentially cost effective. But the plan also recognized that wind, and other intermittent generating resources, pose challenges for integration into the Northwest's power system. The plan called for a wind confirmation plan to be informed by the development of 500 megawatts of commercial-scale wind generation between 2005 and 2009. Ultimately, the plan found that up to 5,000 megawatts of wind could be developed over the 20 years of the plan, assuming that transmission and integration issues could be addressed.

The plan found that the region had a surplus of generating capability and that the need for new generation from coal or natural gas likely would not occur until after 2012, after the 5-year action plan period. During the 5-year action plan period, the Council pledged to work with others in the region to accomplish three important policy changes. These included: (1) adopting resource adequacy standards; (2) changing the role of the Bonneville Power Administration; and (3) addressing problems in the operation and expansion of the regional transmission grid.

Summary of Major Developments Since Adoption of the Fifth Plan

The regional economy, and in particular energy intensive industrial sectors, has been slow to recover from the 2000-2001 energy crisis that formed the backdrop for the Fifth Power Plan. Energy markets, globally, nationally and locally, have continued to experience high and volatile prices. These prices, combined with prominent attention to climate change, have provided the impetus for aggressive conservation activity, new federal energy policies, and increasing attention to renewable resource requirements at the state and utility level.

High energy prices and concerns about potential climate change policy have also led to the aggressive development of wind power in the Pacific Northwest in the two years since the Council adopted the Fifth Power Plan. New generation capacity and slow demand growth have increased the electrical supply surplus in the region, which further delays the need for new generating capability.

The Council, Bonneville, utilities, and other interest groups have been especially active over the two years since the plan was adopted. This has included major initiatives to redefine the roles of Bonneville and its public utility customers in meeting growth in electricity needs, to develop and adopt resource adequacy standards for the region, to improve transmission planning and expansion, to explain and reduce Bonneville's costs, and to better understand the requirements of integrating large amounts of wind generation into the regional power system.

Purpose of the Biennial Monitoring Report

The Council included in its action plan commitments to monitor and assess the assumptions and forecasts underlying the plan, and to track the region's progress in implementing the plan. Action Item MON-7 states that the Council will provide a biennial monitoring report to document the status of the Power Plan and its implementation. This is the first biennial monitoring report for the Fifth Power Plan.

Assessment of the assumptions and forecasts included in the plan address such issues as whether the demand forecast is representative of actual regional sales of electricity observed since the plan. Recent prices for natural gas, oil, and coal are compared to the forecast ranges and the volatility assumed in the plan. Experience with the cost and efficiency of various generating resources is assessed for consistency with planning assumptions. Tracking new generation development and electric loads provides an indication of changing load/resource balances and possible changes in new resource needs.

The goals of the Council's Fifth Power Plan can be accomplished in many ways. Some activities can be pursued directly by the Council, Bonneville, and regional utilities. Others are more effectively accomplished through legislative action, building code changes, appliance efficiency standards, or actions to transform markets for energy equipment. Implementation progress is the second major component of this biennial monitoring report.

Assessment of the Fifth Power Plan

Key Assumptions

Demand Forecast

Actual electricity sales in the region have not recovered from the 2000-2001 energy crisis to the extent assumed in the plan's medium forecast. In particular, the energy intensive industrial sector continues to lag behind the forecast. In total, actual demand in 2005 was about 1000 average megawatts below the medium case, falling between the medium-low and medium forecasts. A preliminary estimate of 2006 sales shows continued recovery and a move toward the medium case forecast. The assessment of the demand forecast is described in Appendix A.

Fuel Prices

Natural gas prices in 2005 averaged near the high end of the Council's Fifth Power Plan forecast range due to hurricanes Katrina and Rita. But 2006 prices are expected to fall near the middle of the forecast range. Oil prices in 2005 and 2006 were above the high end of the Council's forecast range. Like natural gas, coal prices experienced a cyclical increase in late 2005 and early 2006, but have since fallen back into the Council forecast range.

An examination of other forecasts of oil prices indicates that the Fifth Plan assumptions are probably too low. However, the war in Iraq and general unrest in the Middle East continue to support high oil prices. Neither supply nor demand has fully responded to the higher prices of the last couple of years. Nevertheless, a devalued dollar will result in prices higher than assumed in the Fifth Plan. Fortunately, oil prices have little direct effect on the Council's Power Plan, either for generation or for electricity consumption.

The plan anticipates volatility in natural gas prices similar to what we experienced in 2005. There is insufficient information to justify increasing the Council's anticipated natural gas price range at this time. Even if it were decided that the natural gas price range should be raised, it is doubtful that there would be a significant effect on the Council's plan, particularly the short-term action plan. The probable effect of higher natural gas prices would be to make conservation and wind more attractive. However, the near-term acquisition on conservation and wind in the plan are constrained by expectations of maximum feasibility and resource needs respectively. A more detailed description of the fuel price assessment is in Appendix B.

Electricity Prices

The electricity price forecasts for the Fifth Power Plan average very close to actual electricity prices between 2005 and September 2006. Actual prices contain significantly more volatility than the forecast, however. This reflects the pattern that was observed in natural gas prices as a result of hurricanes Katrina and Rita in the summer of 2005. In addition, the effect of a good snow pack and an early runoff resulted in low electric prices in the spring of 2006. Such electric price volatility was modeled in developing the Power Plan.

A change in natural gas prices would affect the electricity price trend forecast, especially in the near term. In the long term, sensitivity studies done for the Fifth Plan showed that higher natural gas prices would have little effect on long-term electricity prices due to compensating changes in fuel choice and plant dispatch. See Appendix C for a more detailed discussion.

Resource Costs

Wind: The pace of wind power development has far exceeded the recommendations of the Fifth Power Plan. Several factors, including high and volatile natural gas prices, the pending expiration of the production tax credit, and risks of climate change policy drive this development. With the rapid pace of wind development has come significant escalation in the costs of developing wind power projects. In addition to the robust demand for wind turbines, other factors have contributed to the substantial increase in the cost of wind projects. Two of these are a weakening dollar and cyclically high commodity prices. This increase in wind costs is expected to be a cyclical phenomenon. We still expect long-term declines in wind costs due to improved technology and materials. However, the passage of state renewable portfolio standards could prolong the higher costs by keeping demand for wind generation development high. Additional information on wind will be developed through the wind integration action plan. Completion of that analysis is a high priority. Appendix D describes recent changes in the cost of wind power.

Gas-Fired Technologies: An assessment of recent experience regarding capital costs and the efficiency of gas-fired generating technologies shows that the assumptions used in the Fifth Power Plan remain representative. The remaining factor in the total cost of power from these plants is fuel prices, which was addressed earlier. Recent work on capacity adequacy standards has shown that summer generating capacity issues may become more prominent for the region. In addition, rapidly growing wind generation creates a need for resources that can be cost-effective for firming intermittent generation. Some natural gas-fired generation technologies may be more cost-effective in this context. Further analysis of these issues will be needed in the next power plan. See Appendix E for an analysis of the cost and efficiency experience in natural gas-fired generation since the Fifth Power Plan.

Coal: The assessment of coal-based generation technologies identified some changes that should be investigated further. Super-critical coal generation technology appears to be advancing more quickly than gasified combined-cycle (IGCC) technology. In the Fifth Power Plan, super-critical technology was used as information to shape future cost and efficiency of traditional coal plants.

The assessment found that the availability of all types of coal plants should be raised from the mid-80 percent range to 90 percent. Reaching 90 percent availability for an IGCC plant would require installing a spare gasifier, which would increase the capital cost of the plant. For most coal-based technologies the assessment found that efficiency experience is slightly lower than the assumptions in the Power Plan. Only super-critical coal technology seemed to be performing a bit more efficiently than assumed in the Power Plan. In future Power Plan analysis, the Council should evaluate a CO2 sequestration-ready IGCC plant, consider the availability of petroleum coke as a fuel source for gasification, and investigate emerging technologies for carbon capture from conventional pulverized coal plants. These changes should be explored in analysis and tested before the next Power Plan, but would not affect the near-term action plan in the Fifth Power Plan. The coal assessment is described in Appendix F.

Other Generating Technologies: There are a number of other generating technologies that were considered in developing the Fifth Power Plan, but for various reasons did not make it into the portfolio of resources recommended in the plan. These include nuclear, geothermal, biomass, hydropower, ocean and tidal current, oil and petroleum coke, solar, and wave energy. Some new information is available on geothermal and hydroelectric potential and cost and this should be explored before the next plan revision. Nuclear generation is getting increasing attention and will benefit from incentives provided in the 2005 Energy Policy Act. It is also being considered in a couple of regional utilities' integrated resource plans (IRPs). Commercial feasibility still appears to be very late in the Council's planning horizon, but the development of advanced designs needs to be monitored. Other technologies are early in their development and do not require updating until the next plan is developed. These technologies are described in Appendix G.

Load - Resource Balance

The Power Plan estimated that the region was about 1,500 average megawatts surplus in 2005, which was a dramatic change from a 4,000 average megawatt deficit in 2000. This change was accomplished through a combination of large demand reductions and the addition of new generating resources. The plan forecast that the surplus would remain about 1,500 average megawatts in 2007.

However, due to slow demand recovery and significant new wind generation, the surplus now is estimated to reach 2,400 average megawatts in 2007. Based on the fact that non-DSI loads are below the medium forecast, as noted above, the actual surplus may be somewhat larger. This increased surplus would delay the need for new electricity generation capability beyond the time estimated in the plan. Appendix H documents the change in load-resource balance.

Implementation Status

Conservation

An assessment of the region's success in meeting the Council's aggressive conservation targets in 2004 through 2006 shows that the region has been largely successful in meeting the targets, at least through 2005. Although the region as a whole is close to meeting the conservation targets in the plan, there are several utilities that fall far short. These shortfalls are offset by the fact that some large utilities are substantially exceeding their share of the targets. The cost of acquiring this conservation seems well aligned with the assumptions used in the plan. In working with utilities to implement conservation and develop IRPs, staff is seeing resurgence in commitment to energy efficiency improvement. Appendix I documents the conservation implementation in the two years since the adoption of the Fifth Power Plan.

Demand Response

Progress has been slower in development of the 500 megawatts of demand response called for in the plan. Some utilities have developed demand response programs, and demand response provided between 150 and 250 megawatts of load reduction during the July 24 heat event in 2006. However, there does not seem to be great interest in firming up demand response as a resource that has a quantified supply curve and agreed measures of value. As the current surplus declines, and as peaking grows to become a greater concern in the region, we expect demand response to gain more attention. Demand response experience is described in Appendix J.

Generating Resources

A new cycle of resource development has occurred since adoption of the Fifth Plan. The plan foresaw little need for new capacity prior to 2010, and recommended no major resource acquisitions other than 500 megawatts of wind to help confirm the resource potential. However, nearly 1,900 megawatts of new capacity, primarily wind and natural gas, has entered service or is under construction since adoption of the plan. Wind plant construction is driven by extension of the federal production tax credit, the California renewable portfolio standard, and high natural gas prices. Current thinking is that the wind production tax credit is likely to be extended, possibly for several years, but at a declining rate. In combination with the aggressive 2010 renewables target in California and developing state renewable portfolio standards in the Pacific Northwest, this will likely lead to a continued rapid rate of wind power development in the Northwest. A preliminary estimate prepared for the Northwest Wind Integration Action Plan project is for 1,200 to 2,200 megawatts of wind power development from 2007 through 2009. Generating resource development is addressed in Appendix G.

Utility IRPs

Council staff is participating in technical advisory committees for all utilities that are actively engaged in integrated resource planning (IRP). The near-term focus on conservation and wind or other renewables in the Council's plan is shared by most utilities. We have found that the Council's plan provides basic data and assumptions that many utilities use in their planning. Many utilities foresee additional generating resource needs before the Council's Power Plan does. The plan recognized that this was likely to be the case because of the significant amount of independent power generation included in the regional resources counted by the Council. Natural gas and coal are the main IRP resources in the long term, but some utilities are beginning to look at advanced nuclear designs after 2020. Most utilities are reluctant to commit to integrated gasification combined cycle (IGCC) plants at this time, although the technology is being considered as a possibility in the future. Appendix K describes the status and characteristics of utility IRPs.

Policy Developments

Adequacy Standards: The Northwest Resource Adequacy Forum has completed its task of developing voluntary adequacy standards for the region. The Council has adopted the three major components of the standards: (1) an energy adequacy standard; (2) an adequacy warning implementation plan; and (3) a pilot capacity adequacy standard. The participation in the Adequacy Forum’s steering and technical committees has been excellent and the standards appear to have wide support in the region. The Adequacy Forum will continue to refine the standards as the region gains experience. The energy and capacity standards are expected to be incorporated into the Western Electricity Coordinating Council (WECC) reliability rules, scheduled to be completed in late 2007. See Appendix L for further discussion of the adequacy standards.

Bonneville Power Administration Role: There has been an intense effort over the last two years to define a new role for Bonneville in the regional power system, as recommended in several regional processes, including the Council’s Fifth Power Plan. This effort, called the Regional Dialogue, appears to be making progress toward achieving goals that have generally been agreed to within the region, and which are included in the Council recommendations. Comments on Bonneville’s Regional Dialogue proposal closed on October 31, 2006. Negotiations are continuing on several aspects of the proposal, and on the details of how the change in policy will be implemented. In spite of many details that remain to be fleshed out, progress toward agreement is encouraging. Bonneville is scheduled to complete a record of decision on the policy in January. For further discussion, see Appendix M.

Transmission Changes: The Council described several important problems in the regional transmission system in its Fifth Power Plan. The Grid West organization intended to address most of these problems, but the region could not agree on implementing the Grid West proposal. A follow-up effort by a smaller number of utilities centered around Bonneville, called Columbia Grid, may address some of the issues, but is moving very carefully and slowly. Another effort by a different group of utilities on the east side of the region, called the Northern Tier Transmission Group (NTTG), has just been initiated. The Northwest Transmission Assessment Committee (NTAC) continues to look at transmission issues on a region-wide basis. Meanwhile, the 2005 Energy Policy Act gave expanded authority for reliability and transmission to FERC (Federal Energy Regulatory Commission) and NERC (National Electric Reliability Council). NERC and WECC (Western Electricity Coordinating Council) are undertaking initiatives to improve transmission system operations. This effort will address several of the problems, but with a west-wide perspective, which may preclude regional organizations like ColumbiaGrid and NTTG from needing to act in these areas. Transmission issues and efforts to address them are included in Appendix N.

Federal Energy Legislation: The Energy Policy Act of 2005 (EPAct 2005) contained numerous provisions that will affect the Pacific Northwest to some degree. Expanded FERC and NERC authority in the area of reliability may help resolve some of the transmission problems cited in the Power Plan. WECC implementation of these provisions may also help encourage compliance with the voluntary adequacy standards developed by the Northwest Adequacy Forum and adopted by the Council.

In addition, EPAct 2005 contained many provisions to encourage energy efficiency and demand response and to support development of specific types of generating resources. For example, there are new energy tax credits for clean coal, advanced nuclear, and several other innovative or renewable technologies. The effects of EPAct 2005 on energy efficiency are further discussed in Appendix I. Appendix O contains a discussion of other legislative changes at the federal and state level that will likely affect implementation of the Power Plan.

State Policy: Much of the state energy legislation activity has revolved around renewable portfolio standards. Montana and Washington have standards in law and Oregon is developing aggressive goals for legislative action. Washington and Oregon have adopted improved appliance efficiency standards, and all states have updated, or will soon be updating, their building energy codes. An Idaho interim legislative committee is working on a state energy policy.

Policy changes in California can also affect the Pacific Northwest. California has adopted aggressive enforceable renewable portfolio standards, resource adequacy requirements, and climate change mitigation policies. In addition, California has developed a Market Redesign and Technology Upgrade (MRTU) to correct the flaws in the design of the California energy market.

Implications for Long-Term Plan and Action Plan

Likely Effects of Major Changes on the Plan

The implications of the biennial assessment of the Power Plan can be looked at from two perspectives, the long-term resource plan, and the short-term action plan. Long-term resource choices that require no action for the next several years do not require near-term plan revisions. To the extent that some findings would require significant change to the near-term action plan, however, revision could be needed. Therefore, implications for near-term actions are addressed first.

The Power Plan's near-term resource actions are focused on conservation and commercial-scale wind development. Conservation development is progressing well so far. Wind development has far exceeded the amount called for in the action plan, but this provides ample opportunity to assess the integration issues that the commercial-scale development was intended to inform.

Rapid wind development, combined with slow recovery of industrial electricity demand, has increased the regional surplus of generating capability. The effect of a higher surplus would be to push other resource acquisitions further into the future, providing additional time to achieve conservation savings and confirm the ability and cost to integrate wind into the regional power system. At the same time, the region needs to be wary of overbuilding generation capability. Some surplus protects against high and volatile electricity prices. Too much surplus can result in a high-cost electric system and increase the cost of Bonneville's power by lowering the market value of nonfirm hydropower generation.

The other focus of the near-term action plan is on regional energy policy actions related to ensuring adequate power supplies, changing Bonneville's role, and resolving regional transmission issues. The resource adequacy actions in the Power Plan have been achieved, but there will be continued attention needed to implement and refine the standards. The Regional Dialogue process appears to be making good progress toward protecting the region's access to the Federal Columbia River Power System. While the actors that were contemplated in the plan to address the region's transmission problems have changed, due to the failure of Grid West, the inception of ColumbiaGrid and NTTG, and the increased responsibility and authority given to FERC, NERC, and WECC by national energy legislation, there is still progress being made in solving these problems. No modifications to the plan are necessary to continue that progress.

Federal and state policy developments contain many provisions that will encourage and support achieving Power Plan goals for conservation and efficient, clean generating alternatives. The development of aggressive renewable portfolio standards in the region and California will require some rethinking of the Council's planning goals and strategies. The Council's mandate in the Northwest Power Act is to develop a least-cost power plan for the region. Renewable portfolio standards impose a different objective into the process that needs to be integrated somehow into the Council's planning process.

Recommendations

The Council recommends that no substantial changes be made to the Fifth Power Plan as a result of this biennial assessment. The near-term actions that are contained in the Power Plan continue to be desirable and justified, and the region is progressing well to carry out those actions.

Some of the changes in fuel prices and generating resource characteristics could change the long-term resource recommendations if the Power Plan analysis were redone. However, no change in near-term actions would be required by possible changes in the long-term resource plan. For this reason, we do not recommend a complete re-evaluation of the portfolio analysis at this time. Staff will continue its ongoing monitoring of plan assumptions and the progress in implementing the plan. In addition, staff will continue to stay abreast of emerging changes in technology for both generation and conservation.

During the next year, staff will need to pay particular attention to some of the changes observed in the biennial assessment. Some additional analysis and testing should be done to update fuel price and demand forecasts to reflect the latest Council views. The effects of some of the changes observed in coal technologies should be evaluated for their potential effects on the long-term resource portfolio. Petroleum coke may become a feedstock for IGCC plants and the market for it needs to be better understood. New information on geothermal and hydroelectric generation needs to evaluated and used to update estimates of the availability and cost of those resources.

Other near-term actions in the Power Plan and the Power Division Work Plan remain relevant and should be pursued as planned.

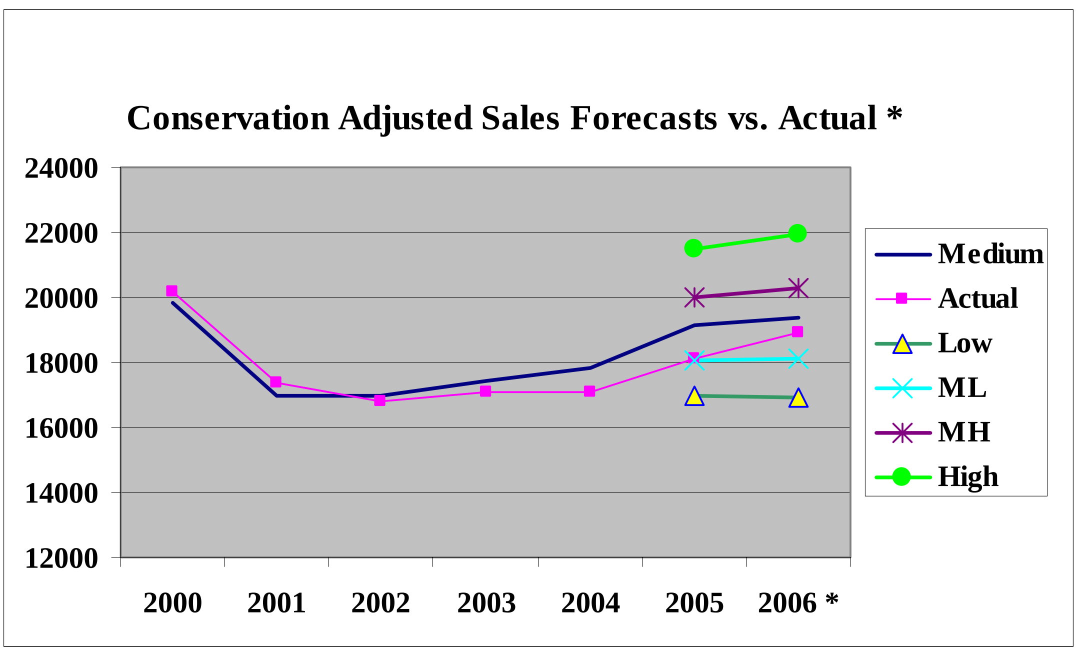
Electricity Demand

Summary

A 20-year forecast of electricity demand is a required component of the Council's Fifth Northwest Power Plan. In the Fifth Plan, electricity demand was forecast to grow from 20,080 average megawatts in 2000 to 25,423 average megawatts by 2025 in the medium forecast. The average annual rate of growth in this forecast is just less than 1 percent per year. This is slower demand growth than forecast in the Council's Fourth Power Plan, which predicted growth at 1.3 percent per year from 1994 to 2015.

As a result of the 2000-01 energy crisis, regional sales of electricity went down by about 2,800 average megawatts, from 20,082 MWa in 2000 to 17,255 MWa by the end of 2001. The bulk of the decline in sales was in the direct service industry (mostly aluminum), which decreased from 2,477 aMW in 2000 to 287 aMW by 2001. Since 2001, regional demand has been recovering. By 2005, most sectors except industrial had recovered to their 2000 sales levels. In aggregate, the actual sales of electricity have been consistent with the medium-low to medium forecasts. Figure 1 shows the comparison between forecast and actual sales (2006 figures are an extrapolation based on growth rates in the first six months of 2006).

Figure-1



Regional Economy

The growth in regional economic parameters has been moderate. After the mild recession of 2001-2002, the region's economy has been growing at a significantly faster rate than the national economy. The data shown in Table 1 present the recent trends in population, regional output, employment and electricity sales. The economic picture of the region indicates a steady recovery over the last few years. During the 2000-2005 period, the Northwest regional economy grew at an annual rate of 3.5 percent compared to a national growth rate of 3 percent.

Table 1- Regional Economy and Electricity Sales

	2001	2002	2003	2004	2005*	Growth Rate 2000-2005
Population (millions)	**11.69**	**11.84**	**11.98**	**12.12**	**12.28**	**1.2%**
Gross State Product (2000$ M)	**388**	**394**	**401**	**423**	**445**	**3.5%**
Employment (thousands)	**7022**	**6994**	**7043**	**7216**	**7438**	**3.5%**
Electricity Sales MWa	**17255**	**16756**	**17294**	**16733**	**18225**	**1.4%**

Compared to the 2000 level of sales, all sectors except industrial have recovered and increased their sales. Table 2, and Figures 2 and 3 show the actual sales for 2000, 2001, and 2005 as well as what the medium forecast for 2005 was. In aggregate, forecasted demand was above the actual by 1,166 MWa, mainly due to slow recovery of the industrial sector.

Table 2- Actual and Forecasted Sales (Average Megawatts) Weather Adjusted

	2000	2001		2005	2005	2005	2000-2005
	Actual*	**Actual***		**Actual****	**5th Plan Medium Forecast**	**Difference from forecast**	**Average annual Growth Rate**
Commercial	**5,219**	**5,058**		**5,823**	**5,453**	**370**	**2.2%**
Residential	**6,724**	**6,571**		**7,252**	**7,262**	**-10**	**1.5%**
Industrial	**7,315**	**4,688**		**4,205**	**5,862**	**-1,657**	**-10.5%**
DSI	**2,477**	**287**		**311**	**958**	**-647**	**-34.0%**
Non-DSI	**4,838**	**4,401**		**3,894**	**4,904**	**-1,010**	**-4.3%**
Irrigation	**652**	**742**		**756**	**629**	**127**	**3.0%**
Other	**172**	**196**		**189**	**185**	**4**	**1.9%**
Total Sales	**20,082**	**17,255**		**18,225**	**19,391**	**-1,166**	**-1.9%**
Total Non-DSI Sales	**17,605**	**16,968**		**17,914**	**18,433**	**-519**	**0.3%**

* Weather adjusted ** Preliminary

Figure 2

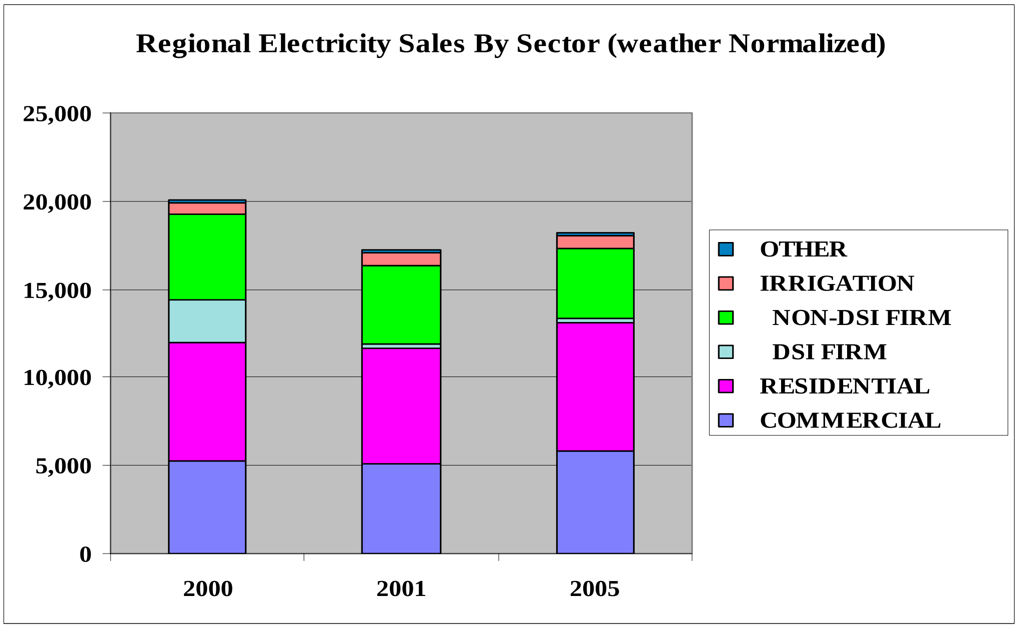
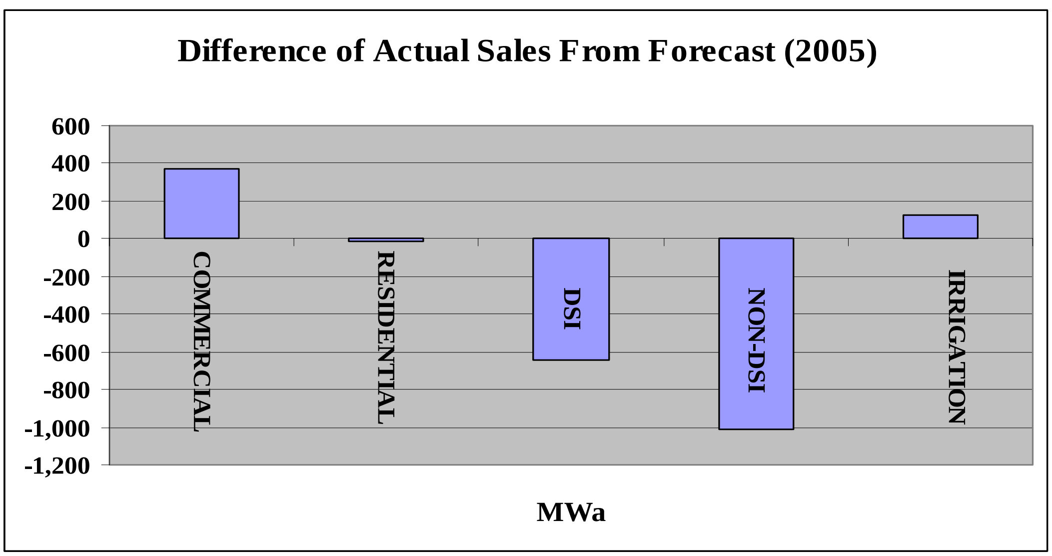


Figure 3



Residential Sector

Population and the number of households in the region increased at an average annual rate of 1.3 percent between 2000 and 2005. Preliminary estimates for 2005 show that electricity sales to the residential sector kept up with population growth, at about 1.5 percent per year, while the electricity consumption per household was consistent with the long-term trends. The Plan's forecast of residential electricity sales for 2005 was 7,262 MWa, preliminary estimates put the actual sales in 2005 at 7,252 MWa. This suggests that the residential forecast is on track with the actual.

Commercial Sector

The key drivers for energy demand in the commercial sector are employment, output produced in the service sector, and the building square footage engaged in various activities in the sector. Commercial employment in the region represented about 80 percent of total employment and about 77 percent of regional output. Between 2000 and 2005, commercial sector employment grew at a rate of 3.1 percent per year, while, on a constant 2000-dollar basis, the output from this sector grew at 2.3 percent per year, and demand for electricity in this sector has grown at 3.6 percent per year. Increases in commercial sector employment and output have translated into 219 million square feet of new commercial floor space between 2001and 2004. The preliminary estimate for commercial sector electricity consumption in 2005 is 5,823 MWa; the medium forecast for electricity sales to this sector is 5,453 MWa by 2005.

Non-DSI Industrial Sector

Between 2000 and 2005, manufacturing employment decreased at the rate of 4.2 percent per year. In the first four years of this period, the real value added from the manufacturing sector grew at 4 percent per annum. During the same period, sales of electricity to the non-DSI manufacturing sector decreased by 4.3 percent per year, dropping from 4,838 MWa in 2000 to about 3,900 MWa in 2005. The increase in manufacturing output, combined with reduced levels of employment and a decline in electricity sales reflect the continued trend toward fewer electricity intensive industries in the region and higher labor productivity. The Plan's forecast for electrical use by non-DSI Industrial sector for 2005 was 4,900 MWa compared to the actual level of 3,900 MWa.

Direct Service Industries:

Aluminum smelters account for most of the industrial load served directly by Bonneville. Aluminum smelters have not recovered from the 2000-2001 energy crisis. By 2005 only three smelters, Wenatchee, Alcoa Ferndale (Intalco), and Columbia Falls operated a total of four potlines. The combined load of smelters operating in 2005 was about 300 MWa compared to over 2,400 MWa in 2001. The medium forecast expectation was for a higher level of DSI operation at 900 MWa by 2005.

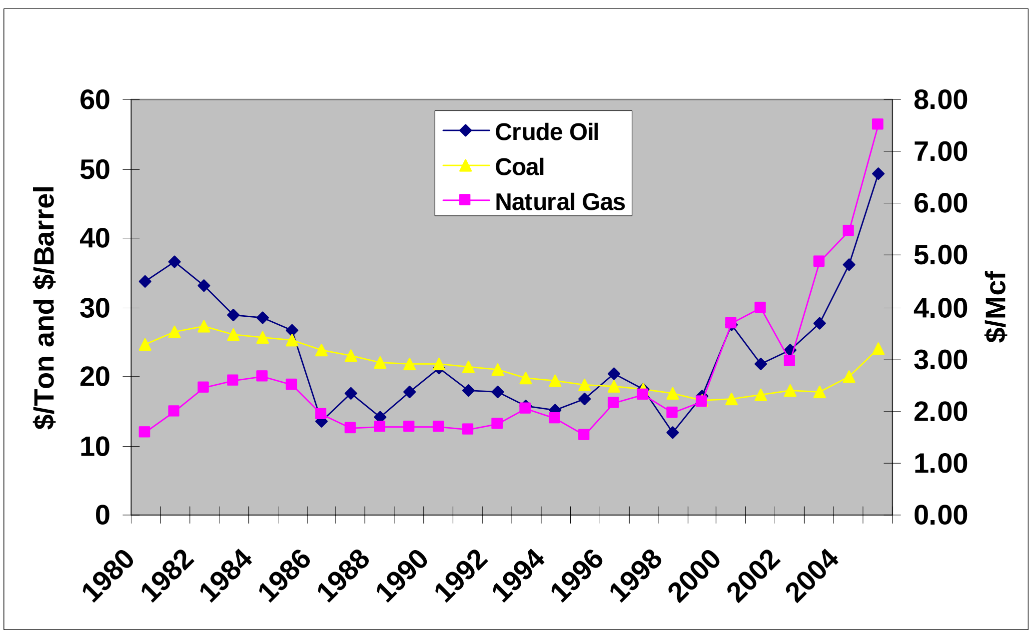
Fuel Prices

Summary

The Fifth Power Plan includes price forecasts for natural gas, oil, and coal. Natural gas prices have by far the most significant effect on the Power Plan. The Council has always forecast a range of prices for fuels to reflect future uncertainty. A significant addition in the Fifth Power Plan was to consider volatility in natural gas prices in addition to the long-term uncertainty of price trends. The Council's range of natural gas trend assumptions is described in Appendix B of the Plan along with a discussion of how volatility in prices is modeled.

The Fifth Power Plan was developed immediately following a dramatic increase in energy prices in 2000. This increase followed more than a decade of low energy prices since the mid-1980s. Figure 1 shows energy commodity prices since 1980. Between 1986 and 1999 natural gas prices averaged $1.87 per thousand cubic feet in nominal dollars, and $2.40 in 2005 dollars. Since 1999 natural gas prices have been much higher and very volatile. At the same time, world oil prices have increased from an average of $22.17 per barrel (in 2005 dollars) between 1986 and 1999 to $49 in 2005. During 2006 world oil prices exceeded $70 (nominal) at times, but fell to under $60 toward the end of the year. Higher oil and natural gas prices have put some pressure on coal prices as well, although they remain lower and relatively more stable.

Figure 1
Energy Prices: 1980-2005



Between 2000 and 2005 natural gas prices averaged $5.00 in 2005 dollars per million Btu; more than double the average between 1986 and 1999. The very high prices from late 2005 until recently were strongly influenced by the destructive hurricanes in the summer of 2005 (Katrina and Rita). Prices had remained stubbornly high in spite of a much warmer than normal winter and higher than normal natural gas storage levels. Only toward the end of 2006 did natural gas prices dropped significantly to levels, at times, below $4.00 (nominal).

The forecast of natural gas prices in the plan assumed that prices would peak in 2005, gradually decline until 2010, and then grow relative to general inflation levels for the remainder of the planning period. The amount of decrease until 2010, and the rate of increase thereafter, varied across the range of trend forecasts. In addition, continued volatility was assumed to occur in the future and this undoubtedly had a significant effect on resource choices in the Plan.

The oil price forecasts in the plan did not envision prices such as materialized in 2005 and 2006. The high forecast for 2005 in the Plan was $43 per barrel (nominal) compared to an actual price of $49. During the first half of 2006 oil prices averaged $60 per barrel. Like natural gas, oil prices have fallen recently, but remain above the Council's forecast range. However, the oil price forecast has little consequence for the Council's Power Plan. Oil is not a significant alternative to natural gas or electricity in Northwest consumption, nor does the region have significant oil-fired generating capability.

The Council's Plan assumed that coal prices, which had been decreasing for decades, would level off. Coal price has little role in end-use consumption in the Northwest. However, coal prices do affect the cost of coal-fired electricity generation. In addition, the delivered price of coal to power plants located in the region will be affected by diesel fuel costs for trains that deliver coal to the plants. Recent higher prices for coal are partially related to higher oil and natural gas costs. Increased use of coal instead of natural gas increased pressure on rail capacity to deliver the coal and higher oil prices increased the delivery costs as well.

Both natural gas and coal-fired generation played a role in the Plan, but actual commitments to such plants was beyond the five-year action plan period. Wind and improved efficiency were the most attractive resources in the plan for the near term. The action plan called for aggressive efficiency investment and for confirmation of wind potential.

Natural Gas

Recent Prices

Because of its significance in the Power Plan, natural gas is the primary focus of this assessment. What does recent data tell us about the validity of the Council's assumptions in the Fifth Power Plan? The Power Plan was adopted in December 2004 and the natural gas price forecasts were based on data before 2004. Figure 2 shows actual monthly natural gas prices at Henry Hub compared to the Council's annual forecast range in nominal dollars. Figure 3 shows how average annual prices during this time compared to the Council's forecast range.

Figure 2
Monthly Natural Gas Price Comparisons at Henry Hub

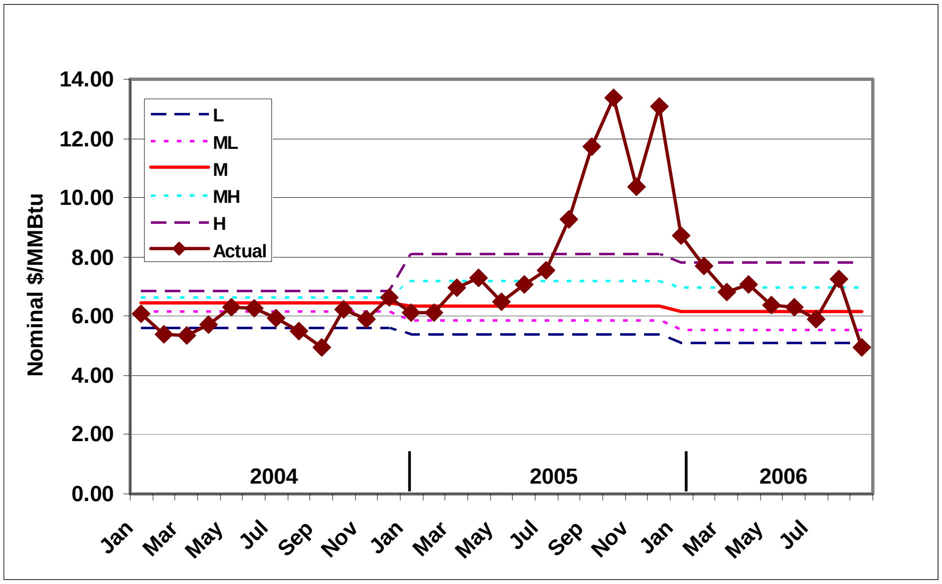
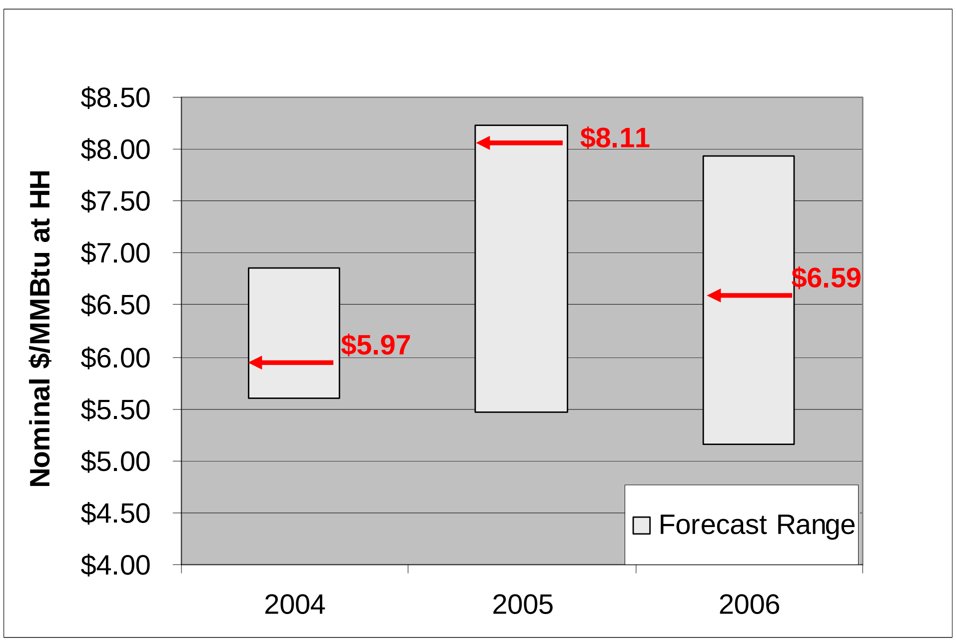


Figure 3
Forecast Natural Gas Price Range Vs. Actual



It has been conventional wisdom in the region that the Council's natural gas price forecast is outdated and too low. However, Figures 2 and 3 show a different story. All three years of natural gas prices were within the Council's range of forecasts. Only 2005 prices were near the high end of the range. Figure 2 shows clearly the effect of hurricanes Katrina and Rita in the summer of 2005 on natural gas prices. During late 2005 and 2006 the loss in production was absorbed, with the help of a mild winter and demand reductions, and storage levels have been built to levels well above the five-year average.

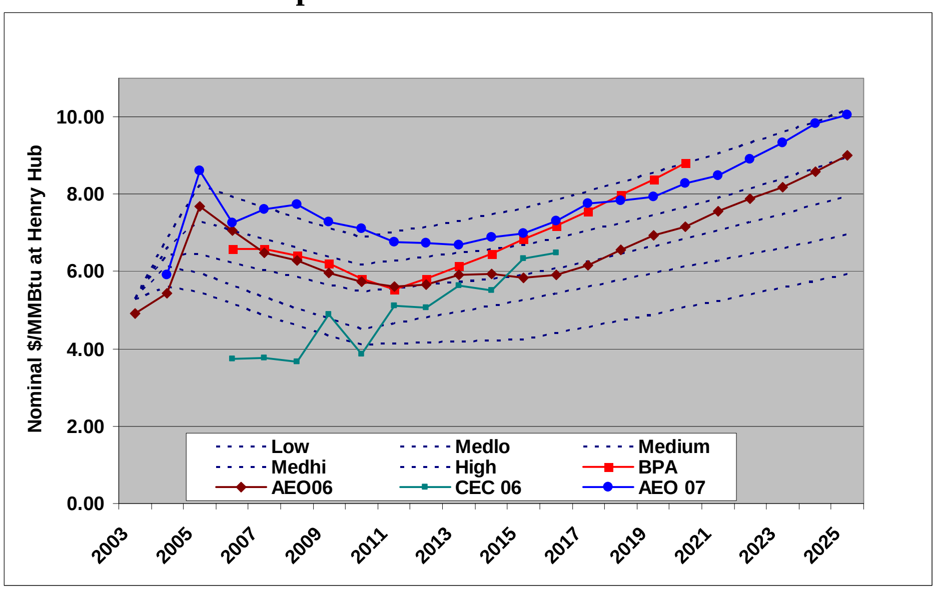
This plentiful storage and a benign 2006 hurricane season have led to a significant collapse of natural gas prices both in the spot market and the futures market in spite of an extremely hot summer. On Monday, October 2, spot prices at Henry Hub were $3.66 per million Btu. Prices at AECO, a primary trading hub for the Pacific Northwest, were $3.26. Prices in the U.S. Rockies supply area fell below $3. Futures prices for natural gas during the coming winter, which had been $10 to $12 for much of the year, have recently fallen below $8. This type of volatility is consistent with the Council's modeling of volatility of natural gas prices in the portfolio model, which includes many excursions well outside the low to high trend forecast range.

On average between January 2004 and September 2006 Henry Hub prices averaged about $7.00. This is just above the Council's medium high trend forecast. Due to the extreme volatility of natural gas markets, it is difficult to conclude much about the Council's trend forecast range based on the last 2-3 years of experience.

Recent Forecasts by Others

Another source of comparison is forecasts by others. We have access to two long-term forecasts of natural gas prices that have been done since the Council's Plan. Figure 4 shows the Council's forecast range in dashed lines compared to a forecast from the Energy Information Administration's Annual Energy Outlook 2006 and a forecast of natural gas prices used by Bonneville in its most recent rate case. Both of these forecasts share the Council's expectation that prices are likely to decrease until about 2010. Both are between the Council's medium and medium-high forecasts leading up to 2010, but fall to the medium Council forecast in 2010. After 2010, both forecasts show more price escalation than included in the Council's forecasts.

Figure 4
Comparison with Recent Forecasts

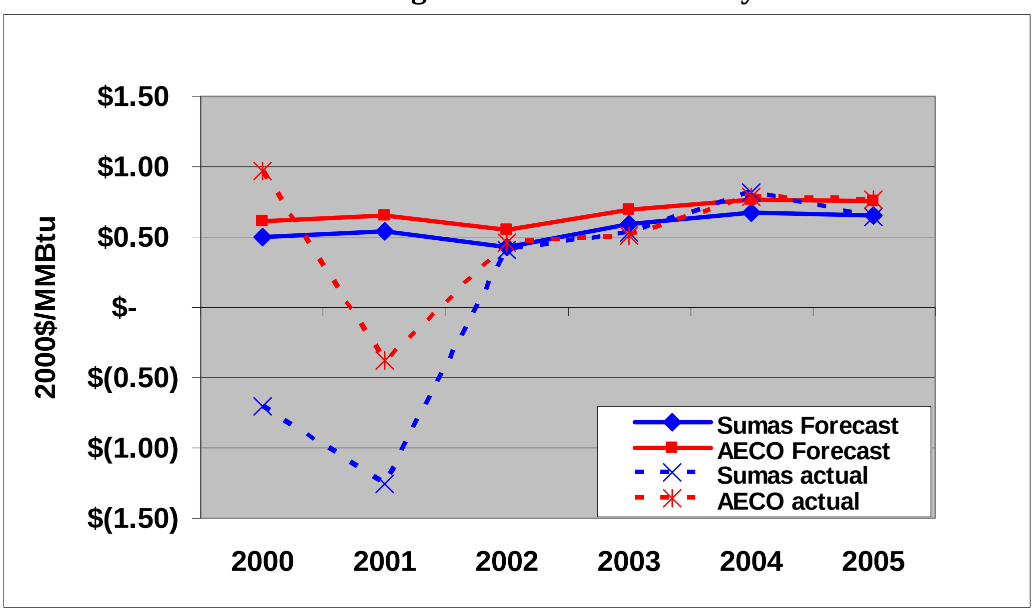


Regional Natural Gas Prices

Natural gas prices that have a direct effect on the Power Plan are prices in the Northwest. The natural gas price forecasts include prices for many pricing points in the West. Prices at major trading points into the Pacific Northwest were forecast based on historical relationships. Natural gas has typically been cheaper in the Pacific Northwest than at Henry Hub. Figure 5 shows differences in price between two Northwest gas trading points (AECO and Sumas) and Henry Hub. The dashed lines are actual differences and the solid lines are forecast differences. Actual differentials are volatile as clearly illustrated for 2000 and 2001 during the energy crisis. After 2001 the forecasts and actual differences track pretty closely. Both increase from around $.50 to $.75 per million Btu.

The price of natural gas delivered into the region from AECO and Sumas are based on estimated pipeline costs to move the gas into the region. For new resources in the Power Plan, these costs are estimated to reflect incremental cost of delivery capacity, which is more appropriate for long-term planning. However, that makes comparison of actual spot prices with the forecasts difficult. Nevertheless, it appears that actual difference between the spot prices of natural gas delivered to Stanfield, Oregon and prices at the AECO trading hub are less than the cost forecast in the Power Plan to deliver natural gas from AECO to Stanfield (or PNW-E). In some years the Stanfield prices are actually lower than the AECO price. This is probably due to the delivery of low-priced natural gas from the Rocky Mountain area, which has limited exporting pipeline capability, to Stanfield via the Williams Northwest Pipeline. It is likely that the higher delivered prices used in the plan are more appropriate to a power plant that has purchased pipeline capacity to ensure its ability to get natural gas when it is needed. This is an issue that staff will discuss with the Natural Gas Advisory Committee.

Figure 5
Discount of Regional Prices from Henry Hub

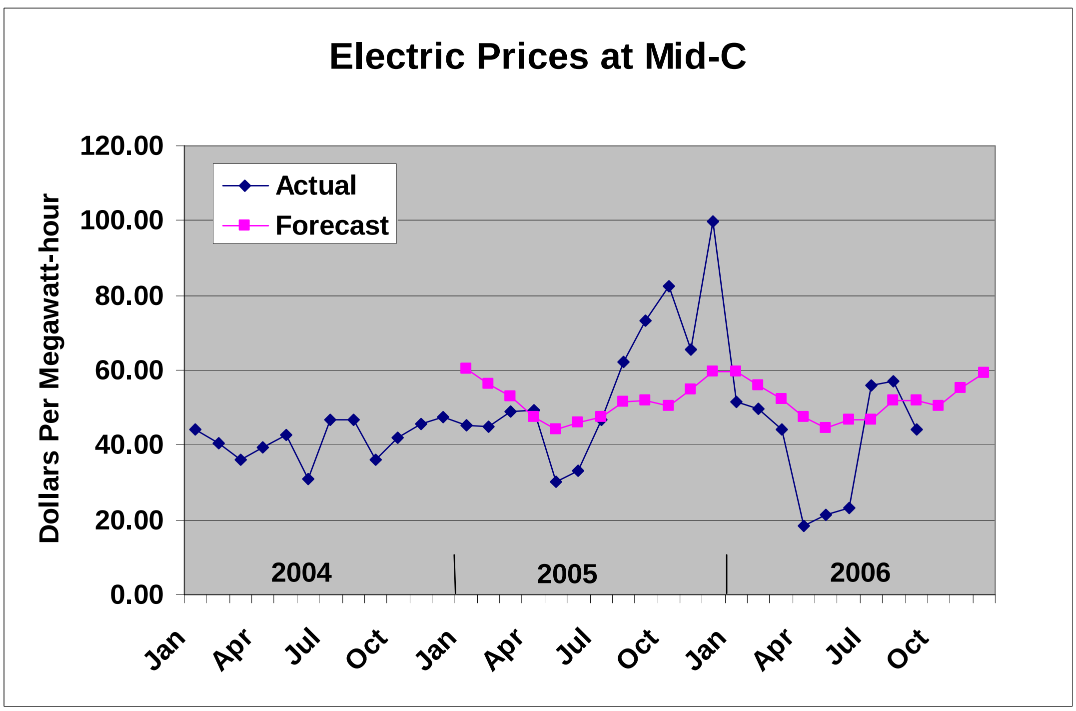


Electric Prices

Electricity prices in the Council's Power Plan are forecast using the AURORA™ Electricity Market Model of the entire Western Electricity Coordinating Council (WECC) area interconnection. The forecast includes electricity prices at several pricing points in the West, four of which are in the Pacific Northwest. The one most easily compared to the Pacific Northwest is the eastern Washington and Oregon price, which is taken to represent the Mid-Columbia trading point.

Figure 1 compares the Plan forecast of Mid-Columbia electric prices in 2005 and 2006 to actual prices observed between January 2004 and September 2006. During 2005 and 2006 actual electric prices have been more volatile than the Aurora forecast. This is expected because the Aurora forecast was based on medium trend natural gas prices and average water conditions. The spike in electric prices during the fall and winter of 2005 are due to high natural gas prices following hurricanes Katrina and Rita in the summer of 2005. Natural gas prices and electric prices are strongly related because natural gas-fired electric generating plants are on the margin much of the time in Western markets.

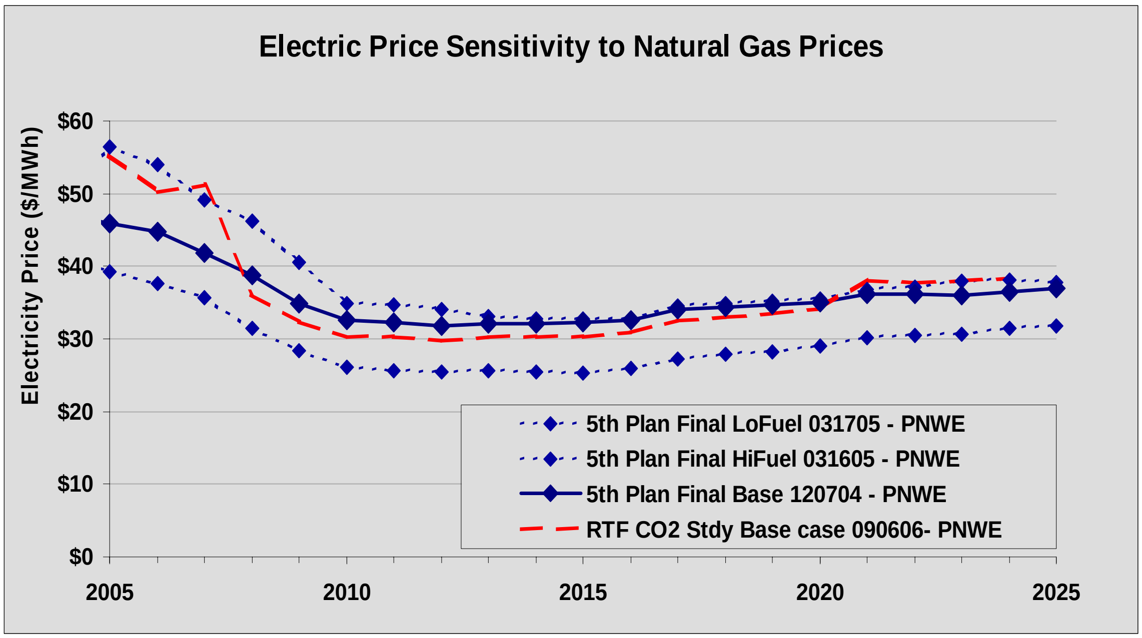
Figure 1



Mid-Columbia electric prices dropped during April, May, and June 2006 reflecting good hydroelectric conditions and an early runoff of snow stored in the mountains. On average, for 2005 and 2006 through September, forecast prices are very close to actual prices. Actual prices averaged $50.14 per megawatt-hour compared to forecast prices of $51.37.

Because of the close relationship between natural gas prices and electric prices, errors in the natural gas price forecast would tend to translate into errors in the electric price forecast. The effects of different natural gas price assumptions are illustrated in Figure 2. The solid line with diamonds is the Plan base forecast. The dashed lines with diamonds are low and high natural gas prices sensitivity studies. The dashed line without diamonds is a special sensitivity based on short term forecasts made during a high natural gas price period but merged into the Council's medium forecast after 2010. The sensitivities show how electric price forecasts are related to natural gas price assumptions. There appears to be more sensitivity in the short term than in the long term for higher natural gas prices. The high natural gas price case is not much different than the medium case after about 2012. This is because high natural gas prices result in a shift to wind and coal generation.

Figure 2



The role of the AURORA™ Electricity Market Model electricity price forecasts in the power plan is indirect. An illustrative supply curve for conservation is based on the AURORA™ electric price forecast as an estimate of avoided electricity costs. However, the conservation role in the Power Plan is based on Portfolio Model simulations that include many different future electric prices that are also volatile over time. The base price forecast serves only as a central tendency for volatile electric price futures in the Portfolio Model.

There is no evidence currently that the electric price forecast is too low. As discussed in the fuel price assessment, there is some inconclusive evidence that fuel price forecasts might be too low. What would a higher forecast of fuel prices, which would translate into higher electric prices, do to the Power Plan? Figure 2 showed that higher fuel prices may increase electric prices in the short term, but would have little effect in the longer term as the resource mix shifts away from natural gas. Additional conservation development in response to higher electricity prices is considered unlikely in the Power Plan. In the short term, the amount of conservation included in the Plan is constrained by upper limits on what the Council considered feasible to develop on an annual basis.

Higher electric prices would tend to make wind more cost-effective also, but in the short term, wind actions in the Plan relate to confirmation activities rather than a need for additional electric generation. Therefore, higher fuel prices in the short term would have little effect on the action plan recommendations.

The other possible effect of higher near-term electric prices would be to reduce the demand for electricity, further delaying the recovery of demand from the 2000-01 electricity crisis. This would have the effect of prolonging the existing surplus of generating capability and delaying the need for significant new generating investments, which is already beyond the 5-year action plan.

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Wind Power Assumptions

The Northwest Power and Conservation Council, in its 5th Power Plan estimated the levelized cost of new utility-scale wind power to range from \$42 to \$53/MWh[1]. The assumptions upon which these costs are based are shown in the following table[2]. These were developed with the assistance of an advisory group comprising of industry and utility representatives. The assumptions date from 2002, a time of moderate wind development activity and were thought to be representative of equilibrium market conditions, suitable for the long-term nature of the Council's Plan. Conditions through late 2004, when the Fifth Plan was adopted, did not appear to significantly deviate from these assumptions.

	Year 2000 (2006) dollars
Project Size (MW)	100
Capital (\$/kW)	\$1010 (\$1160)
Fixed O&M (\$/kW/yr)	\$20[3] (\$23)
Variable O&M (\$/MWh)	\$1 (\$1.15)
Capacity Factor (%)	28 - 30%[4]
Shaping & Integration (\$/MWh)	\$4.55 - \$9.75 (\$5.23 - \$11.20
Wheeling (\$/kW/yr)	\$20 (\$23)
Transmission Losses	1.9%
Project life	20 years
Learning effects (on real cost)	-2.2 %/yr

The cost of new wind projects has risen substantially in real terms over the past two years. Proposals for shaped and delivered energy from projects entering service in 2006 or 2007 range from about \$45 to \$90/MWh. The principal element leading to the increase in delivered energy cost is an increase in project construction costs of 20 to 30 percent over the base year capital cost adopted for the Fifth Plan. Factors at play include the following:

Weakening dollar: Major components of many of the turbines used in U.S. wind farms are manufactured overseas. A weakening U.S. dollar against overseas currencies has increased the cost of these machines. For example, the value of the Euro against the dollar has increased from \$0.98 in July 2002 to \$1.21 in March 2006.

Increased commodity and energy costs: Commodities used in the manufacture and installation of wind turbine generators and ancillary equipment, including cement, copper, and steel have increased in cost in recent years. Drivers have included general economic recovery, disaster recovery, and increased demand from developing Asian economies. NYMEX copper increased from \$0.72/lb in July 2002 to \$2.32/lb in March 2006. Rebar has increased about 45 percent over the same period. Structural concrete is forecast to increase to about \$580/cy in 2006, up 50

[1] 2006 dollars, 2005 service, shaped and delivered, inclusive of the federal production tax credit for private financing.
[2] Costs are expressed in year 2000 dollars in the 5th Power Plan. Year 2006 dollars are used here to facilitate comparison to current market conditions.
[3] Excluding property tax and insurance.
[4] Eastern Washington, Oregon and Idaho sites. MT - 36%.

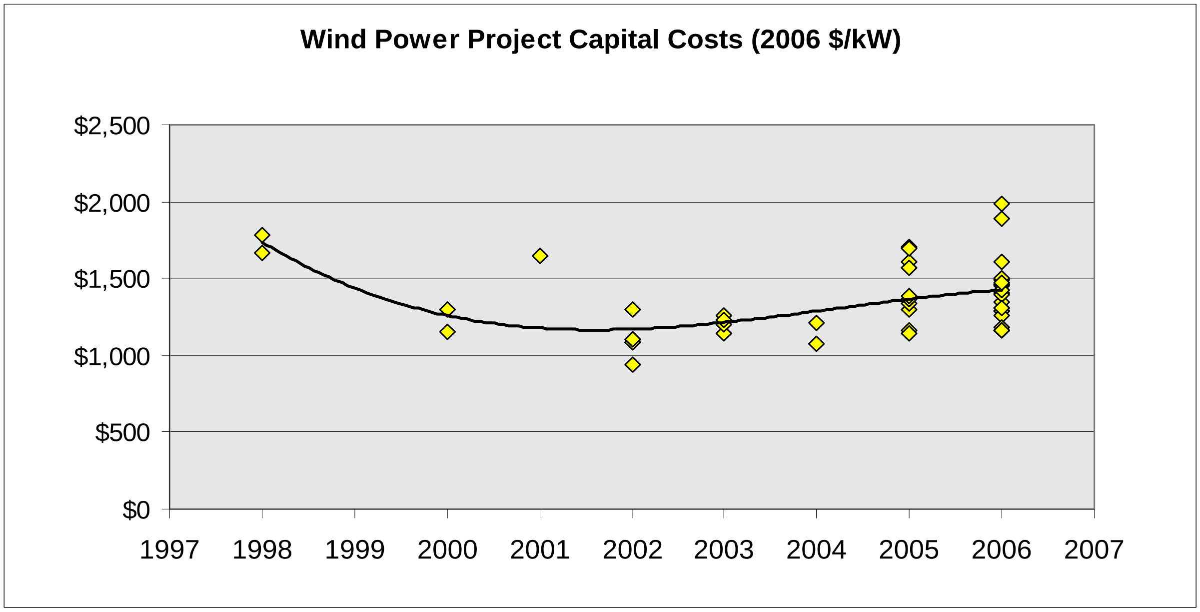
percent from 2002. Likewise, the cost of energy needed to fabricate, transport, and erect wind turbine generators and related components has also increased. The average U.S. retail price of No. 2 diesel has increased from $0.85/gallon in July 2002 to $2.07/gallon in March 2006. There is evidence that some commodity prices may be peaking as new supply is developed or demand is weakening.

Market demand for wind power: The near-term demand for wind power has increased because of increasing natural gas costs, pending expiration of the federal production tax credit (PTC) at the end of 2007, adoption of state renewable portfolio standards and increasing utility recognition of the risk of future CO_2 control costs. Increased demand has created shortages of turbines, specialized transportation and erection equipment, and experienced construction workers and operations and maintenance personnel. In addition, the buyer's market has likely encouraged increased profit taking where possible among players in an industry that has experienced many lean years. Turbines are generally not available through 2007, the last year of the current PTC extension, but remain available for 2008 delivery.

Financing: Changes in the structure and terms of project financing have occurred, motivated by a maturing industry, the federal production tax credit, and accelerated depreciation rates. Financing trends include (1) increasing investor-owned utility ownership of projects; (2) lower debt fractions including unlevered (pure equity) financing for independently owned projects; (3) lower equity return among investors in independently owned projects and (4) emergence of more complex financial structures for the purpose of fully securing PTC and accelerated depreciation benefits.

Performance improvements: Performance improvements are evident, from increases in swept area and hub heights, improved reliability, and improved project and turbine siting. Though not a completely reliable indicator of improved performance, the forecast capacity factors of recent and proposed projects appear to have an improved 2 to 3 percentage points above Fifth Plan assumptions.

The plot of wind project capital costs shown below was prepared using a combination of announced capital costs of utility-scale projects completed or under construction from 1997 through 2005 plus back-calculated capital costs from recent bids. The back calculations were performed under the assumption that the primary factors leading to recent cost increases have been capital and O&M costs (i.e., wheeling and integration costs have remained relatively constant). Capacity factors were assumed to average 32 percent. The resulting plot suggests that capital costs continued their historical decline from 1997 through 2002, picked up slightly in 2003, declined in 2004 with the expiration of the PTC, and subsequently increased under the influence of the factors described above. Capital costs in 2006 range from about $1,160 to $1,990/kW, with an average of about $1,450/kW. This finding is confirmed in conversations with industry representatives who suggest capital costs ranging from $1,430 to $1,550/kW.



The assumptions shown in the following table are proposed for purposes of characterizing typical near-term utility-scale projects. Average project size is assumed to have increased to 150 MW, based on recent Northwest projects. Overnight capital costs, including project development, owner's and typical transmission interconnection costs, are assumed to be $1,500/kW. Fixed and variable operations and maintenance costs are assumed to have increased proportionally to capital costs. The typical capacity factor of a project located in the inland Northwest, based on energy to the point of interconnection is assumed to have increased to 32 percent. Wheeling and integration costs, wheeling losses and project life are unchanged from Fifth Plan estimates. Learning curve effects are assumed to have no effect on real costs in the near term.

	Year 2006 dollars
Project Size (MW)	150
Capital ($/kW)	$1,500
Fixed O&M ($/kW/yr)	$30
Variable O&M ($/MWh)	$1.50
Capacity Factor (%)	32 percent
Shaping & Integration ($/MWh)	$4.55 - $9.75
Wheeling ($/kW/yr)	$20
Transmission Losses	1.9 percent
Project life	20 years
Learning effects (on real cost)	None for near term

These assumptions yield a levelized energy cost of $58, $78 and $78/MWh for COU, IOU and IPP financing,[5] respectively.

[5] 2006 dollars, integrated and delivered based on the existing Fifth Plan financing assumptions. IOU and IPP values are inclusive of the current PTC. Consumer-owned utility costs are not credited for REPI.

Gas Turbine Power Plant Assumptions

Simple- and combined-cycle gas turbine power plants fueled by natural gas are among the bulk-power generating technologies considered in the portfolio analysis of the Fifth Power Plan. The favored bulk power generating technology of the 1990s and early 2000s, natural gas combined-cycle power plants comprise about 11 percent (5,914 megawatts) of Northwest generating capacity. Simple-cycle units, valued for provision of system reliability, regulation, load following and in the Northwest, hydro-power firming, comprise about 3 percent (1,654 megawatts) of generating capacity. Most of the combined-cycle capacity was completed between 1995 and 2004 when the combination of low natural gas prices and reliable, low-emission and efficient gas turbine technology made combined-cycle gas turbine power plants the "resource of choice." Higher natural gas prices since 2001 have reduced the attractiveness of bulk power generation using natural gas. Construction of only one large combined-cycle project has been initiated since 2001. That plant is the Port Westward project, a 399-megawatt project of Portland General Electric, located near Clatskanie, Oregon, scheduled for completion in 2007. That plant employs a higher-efficiency "G-class" gas turbine to help offset high natural gas costs.

The resource portfolio of the Fifth Power Plan includes additional gas-fired power plants following 2018. Up to 800 megawatts of additional simple-cycle capacity and 1,220 megawatts of combined-cycle capacity may be needed by the end of the planning period. Because of established technology and the relatively short time required to site and permit these types of plants, no actions regarding these resources were called for in the five-year action plan.

Technology and Applications

The two basic classes of gas turbines are aeroderivative machines and industrial machines (also called "frame" or "heavy duty" turbines). Aeroderivative turbines, as the name suggests, are derived from the gas turbine engines used for aircraft. They are characterized by light weight, relatively high efficiency, quick startup, rapid ramp rates and ease of maintenance. Aeroderivative turbines tend to be more costly than industrial machines because of more severe operating conditions and more expensive materials. Industrial gas turbines are designed for extended high-output duty. They are characterized by heavier components, somewhat lower efficiency, slower startup time, slower ramp rates and more complex maintenance procedures.

Gas turbines for electricity generation applications are employed in two principal configurations. Simple-cycle units consist of a gas turbine generator and appurtenant equipment. The hot turbine exhaust is discharged to the atmosphere, limiting the efficiency of these units to about 36 percent. Combined-cycle units include a heat recovery steam generator on the exhaust to recover otherwise wasted energy. Steam from the heat recovery steam generator powers an additional steam turbine, providing extra electric power from the same amount of fuel as a comparable simple-cycle unit. Combined-cycle efficiencies range to about 50 percent. In addition, the steam generator of combined-cycle units can be fitted with fuel burners ("duct firing") to boost peak power output. Most combined-cycle plants employ industrial gas turbines.

Because of their higher efficiency, combined-cycle plants are used for base and intermediate load power generation. Simple-cycle units (and the duct firing section of combined-cycle units) are used to meet peak period loads and to provide ancillary services such as frequency regulation and load following where flexibility is more important than efficiency. Industrial simple-cycle machines are suited to longer duration peaks whereas aeroderivative simple-cycle machines are better suited to short duration peaks, short-term load following and frequency regulation.

A new gas turbine configuration has been introduced to production since development of the Fifth Power Plan. The General Electric 100-megawatt LMS100™ simple-cycle gas turbine incorporates an external intercooler between the low-pressure and high-pressure air compression stages. The intercooler cools and increases the density of air entering the high-pressure compressor, allowing a higher compression ratio to be achieved with less energy. This results in higher thermal efficiency over a wider load range and lower sensitivity to high ambient air temperatures. Basin Electric's Groton Generation Station, the first North American project using the LMS100, was commissioned in July 2006.

Fifth Power Plan planning assumptions for simple- and combined-cycle gas turbine power plants are shown in the following table. Also shown are published data for the intercooled LMS100. The cost of the LMS100 plant is based on the announced cost of the Basin Electric Groton plant. This is a first of a kind installation and may not be representative of future plant costs because of possible first-of-a-kind discounts and potential design and production economies.

	5th Plan Aeroderivative Simple-cycle	**5th Plan Industrial Simple-cycle**	**5th Plan Combined-cycle[1]**	**Intercooled Simple-cycle (LMS100™)**
Unit capacity (MW)[2]	2x47	2x80	540/70	96
Heat Rate[3] (Btu/kWh)	9,650	10,240	6,710/9,060	8,430
Efficiency (%)	35	33	51/38	41
Cold Startup (min)	8	20	180	10
Capital cost ($/kW)[4]	$673	$420	$586/$250	$708[5]

Assessment of Cost and Performance Assumptions

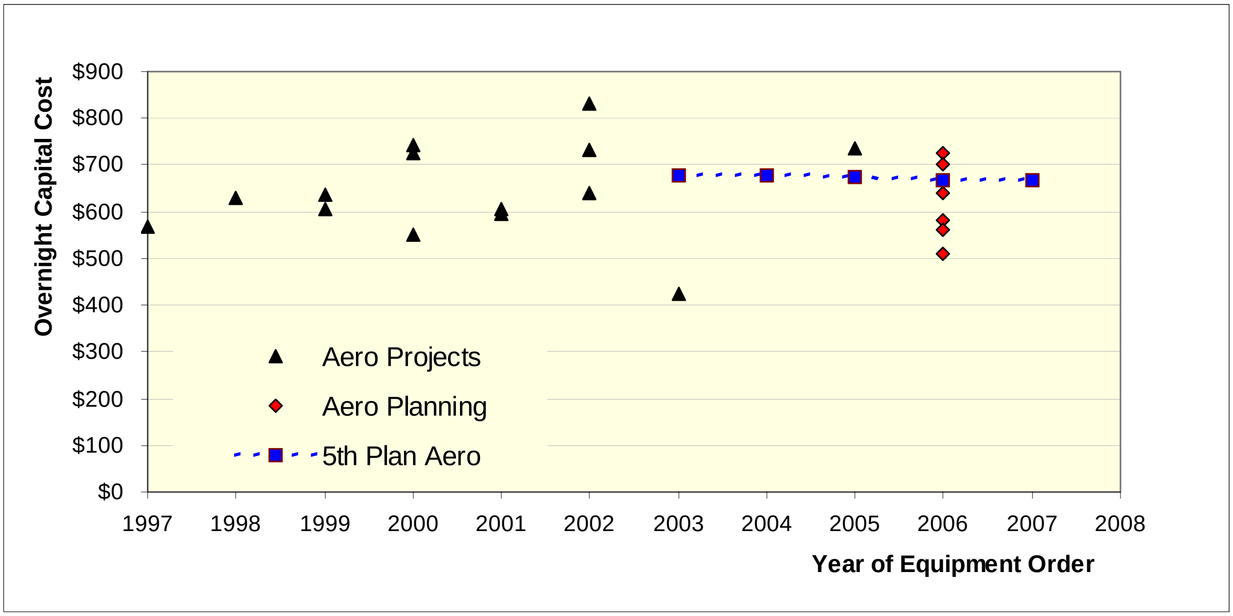
The most significant factors affecting the cost-effectiveness of natural gas power plants are the cost of natural gas (assessed elsewhere), capital cost and thermal efficiency. Capital costs are important for all plants, efficiency is more important for combined-cycle plants.

[1] First value is combined-cycle increment; second value is duct firing increment.
[2] ISO, new and clean, derated for inlet and exhaust losses.
[3] ISO, higher heating value, new and clean.
[4] Overnight cost, 2006 dollars for 2006 order.
[5] Estimated overnight cost of Basin Electric Groton plant using Council financing assumptions.

Capital cost of aeroderivative simple-cycle gas turbine power plants

The Fifth Power Plan cost assumptions for aeroderivative simple-cycle gas turbines are compared in Figure 1 to announced project costs taken from a data base maintained by the Council, as well as budgetary planning estimates published in *Gas Turbine World*. The horizontal axis represents the year of equipment order. The vertical axis represents "overnight" capital cost (2006 dollars). "Overnight" cost is the total construction cost less costs of financing, escalation, and interest during construction. The "Aero project" series (triangles) are the estimated overnight costs of projects constructed in the WECC region for which costs have been announced. Announced capital costs are assumed to be total project costs. Overnight costs were calculated from these using the Council's generic financing assumptions for the type of project developer. The single unit project costs were increased by 10 percent for consistency with Fifth Plan assumptions. The cyclical nature of the market is evident. Prices (and number of projects) increased through 2002 (2003 service), as a result of the energy crisis and peak load growth. The market subsequently collapsed and prices and number of projects declined. The higher cost ($737/kW) of the most recent plant suggests the possible effects of recent increases in materials cost.

Figure 1
Simple-cycle aeroderivative gas turbine power plant capital cost estimates



The "Aero planning" series (diamonds) are based on equipment list prices reported in the *Gas Turbine World 2006 Handbook* and rule-of-thumb balance-of-plant costs. Costs range from $511 to $727/kW.

The Fifth Plan cost estimates are shown as box points along the dashed line. They slowly decline in real terms under the assumption that continuing technical development should result in declining capital cost. The Fifth Plan cost is well within the *Gas Turbine World* planning range though slightly lower than the cost of the most recent WECC project. The equipment prices upon which the *Gas Turbine World* series are based are characterized as representing a recovering market, and as such could be expected to be lower than the equilibrium market price estimates of the Power Plan. The Fifth Plan assumptions appear to remain reasonably representative.

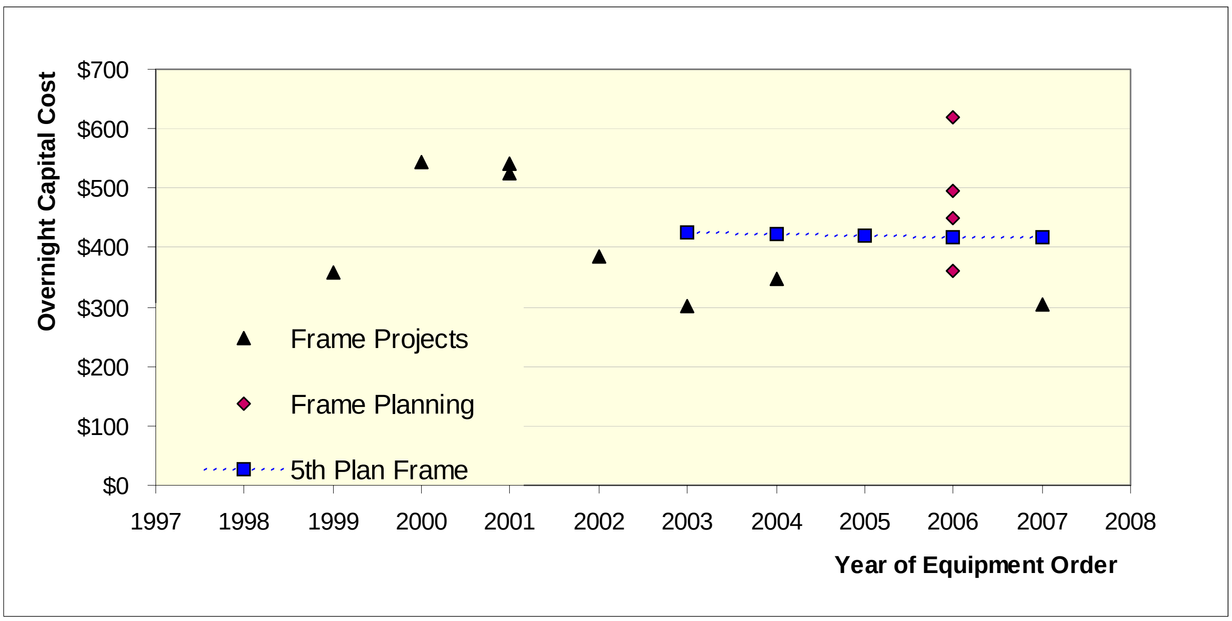
Capital cost of industrial simple-cycle gas turbine power plants

The Fifth Power Plan cost estimates for representative industrial simple-cycle gas turbines are compared in Figure 2 to historical project costs and budgetary planning estimates derived from vendor list prices. As in Figure 1, the horizontal axis represents the year of equipment order and the vertical axis represents overnight capital cost. The "Frame project" series (triangles) are the estimated overnight costs of projects constructed in the WECC region for which costs have been announced. Overnight costs were estimated as described for aeroderivative units. A cyclical market is strongly evident. Unlike the aeroderivative market, the market for industrial turbines appears not to have recovered from the post-energy-crisis collapse. Despite rising materials costs, the cost of industrial gas turbine equipment (representing half of the total plant cost, or more) has remained low because of the glut of surplus industrial turbines, many from cancelled combined-cycle projects.

The "Frame planning" series (diamonds) are based on current vendor list prices as reported in the *Gas Turbine World 2006 Handbook* and rule-of-thumb balance-of-plant costs. Estimated overnight project costs range from $360 to $620/kW.

The Fifth Plan assumptions (boxes along the dashed line) is within the *Gas Turbine World* planning range and appear to represent an equilibrium market, as intended. However, because most new capacity, by definition, is developed in a seller's market, consideration might be given in future power plants to correlating capital costs to need for new capacity.

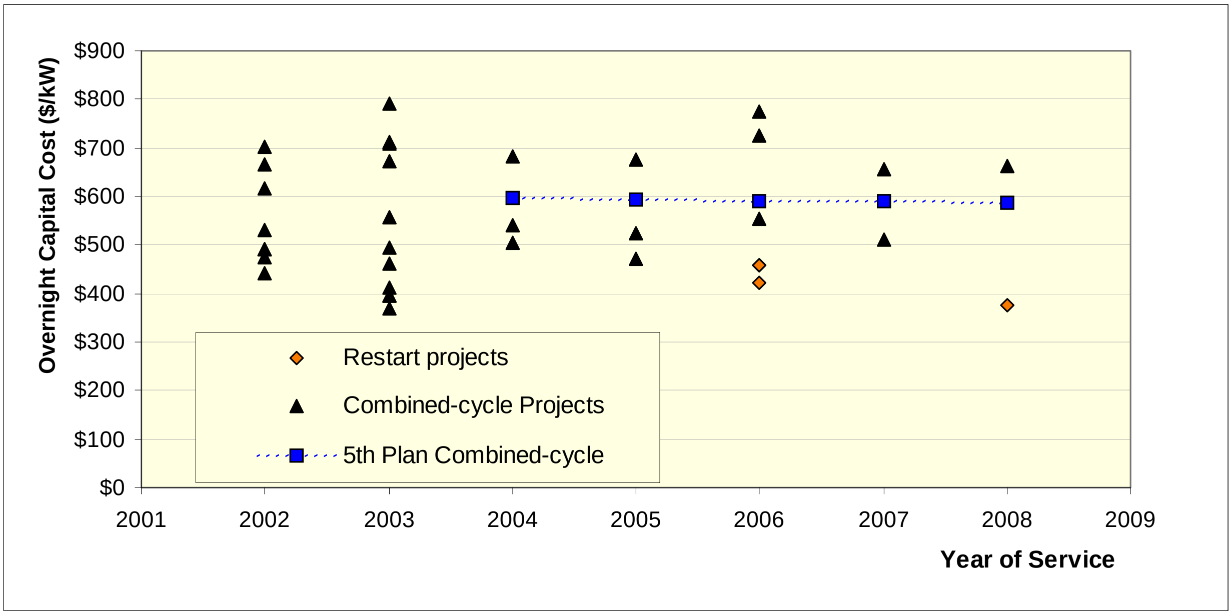
Figure 2
Simple-cycle industrial gas turbine power plant capital cost estimates



Capital cost of combined-cycle gas turbine power plants

The Fifth Power Plan cost estimates for representative combined-cycle gas turbine power plants are compared in Figure 3 to historical project costs. *Gas Turbine World* budgetary planning estimates do not appear in this comparison because of the larger sample of available actual project costs, and because of the greater diversity of combined-cycle plant configurations make simple rule-of-thumb estimates of balance-of-plant costs less feasible. As in Figures 1 and 2, the vertical axis represents overnight capital cost. Here, however, the horizontal axis represents the year of service. The "Combined-cycle project" series (triangles) are the estimated overnight costs of combined-cycle projects constructed in the WECC region for which costs have been announced. Overnight costs were estimated as described for simple-cycle units. Unlike simple-cycle power plants, there is no evidence of a post-energy crisis decline in the cost of combined-cycle plants. This may be because few, if any, combined-cycle plants have used equipment acquired through the secondary market. Moreover, the increased balance of plant complexity results in greater sensitivity to recent escalation in the prices of steel, copper, concrete, and other materials.

Figure 3
Combined-cycle gas turbine power plant capital cost estimates



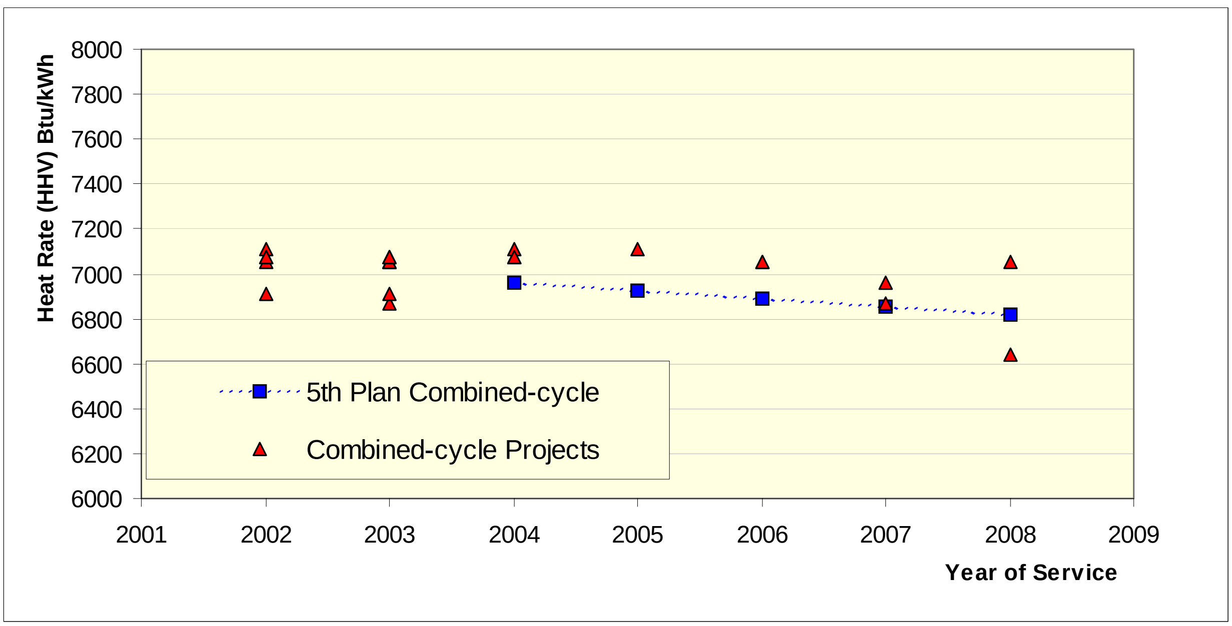
The Fifth Plan assumptions (box points along the dashed line) slowly decline in real terms under the assumption that continuing technical development should result in declining capital cost. The Fifth Plan cost estimates continue to adequately represent the real-world cost of constructing new combined-cycle plants.

The "restart project" series (diamonds) in the lower right of Figure 3, ranging from $376 to $457/kW, represent three projects for which construction was restarted after a prolonged period of suspension. While the cost of completing suspended projects will vary depending upon the extent to which the project was completed prior to suspension and other factors, these values provide a sense of the likely cost of completing suspended projects in the Northwest.

Efficiency of combined-cycle gas turbine power plants

The Fifth Power Plan assumptions for the heat rate of combined-cycle gas turbine power plants are compared in Figure 4 to the estimated heat rates of recently constructed combined-cycle plants. The vertical axis represents heat rate (the engineering measure of plant efficiency) in Btu/kWh[6] and the horizontal axis represents the year of service. The "Combined-cycle project" series (triangles) are the estimated heat rates for recently constructed combined-cycle projects in the WECC region. Because the actual heat rates of power plants are rarely published because of proprietary concerns, the heat rates shown in the figure are equipment vendors' published heat rates for the type and configuration of plant equipment. Information regarding equipment is often available and maintained in the Council's gas turbine power plant database. The heat rates are derated to represent lifecycle values for consistency with Fifth Plan assumptions. Because heat rates vary significantly with plant size, the sample is limited to plants of the same size class (Frame 7) as the plant on which the Fifth Plan assumptions are based The lower value appearing in 2008 is for the Inland Empire power plant in California, the first North American application of advanced "H-Class" technology.

Figure 4
Combined-cycle gas turbine power plant efficiency estimates



The Fifth Plan heat rate estimates (boxes along the dashed line) slowly decline under the assumption that continuing technical development should result in improving efficiency (declining heat rate represents improving efficiency). The Fifth Plan estimates appear to adequately represent the efficiency of new combined-cycle plants.

[6] Heat rate values used here are based on higher fuel heating value consistent with the units used in the Fifth Power Plan.

Conclusions

This assessment of the key non-fuel planning assumptions of the Fifth Power Plan regarding new gas turbine power plants indicates these assumptions continue to be representative of real-world experience. This finding, together with the conclusion of the biennial assessment of the natural gas price forecast, suggests that the role of natural gas-fueled simple and combined-cycle power plants for bulk power generation in the Fifth Power Plan is unlikely to significantly change.

Because the earliest need for gas turbine plants in the Fifth Power Plan portfolio lies well beyond the period of the action plan, no actions pertaining to the possible bulk power generation role of these resources were included in the action plan. Other factors, however, might result in a need for these resources in the nearer term. These include a possible need for capacity to maintain system reliability and possible need for additional system regulation and load following capability for the integration of wind power. The former will be better understood once system reliability criteria are established; the latter is being addressed in the regional wind integration project.

Another factor that might affect the real-world role of gas-fired gas turbine power plants in the Northwest is the presence of over 900 megawatts of combined-cycle plant on which construction was suspended following the collapse of power prices subsequent to the 2000-01 energy crisis. Recent experience in California indicates that these projects might be completed at two-thirds to three-quarters the cost of a greenfield plant. This would reduce the cost of energy from a new combined cycle by about 5 percent, possibly enough to make completion of one of these projects attractive in the face of the cost increases being experienced for other new generating resources.

A final conclusion results from cyclical market evident here for simple-cycle units and observed for wind power and other generating resources. The generating resource capital cost assumptions of the Fifth Power Plan and earlier plans are based on equilibrium market conditions - neither a buyer’s nor a seller’s market. Historically, however, most generating capacity is acquired during buyer’s market conditions, resulting in higher costs than those forecast for equilibrium markets. The cost-effectiveness values of different resources are not equally sensitive to these fluctuations. Future portfolio analyses might consider possible correlations between electricity market activity and resource capital costs.

Coal-Fired Power Plant Assumptions

Rising natural gas prices and the commercialization of advanced coal technologies has renewed interest in coal-fired generation throughout North America. The choice of technology, fuel and site for a developer considering a coal-fired power plant is no longer simple, however. Whereas "coal-fired generation" once implied a single, mature, fairly standardized technology, now, an array of technologies and technology variations, and external factors, competing and uncertain, govern the choice of fuel, sites and technology. Among these are carbon dioxide (CO_2) control policy, increasing availability of petroleum coke[1], higher gas and oil prices leading to the increased attractiveness of polygeneration[2], mercury control policy, changing technology cost and performance characteristics, technology commercialization rate, federal incentives, water availability and public perception.

Conventional and gasification power plants fuelled by coal are among the bulk power generating technologies that were included in the portfolio analysis of the Fifth Power Plan. Action GEN-7 calls for an option to construct 425 megawatts of coal gasification combined-cycle plant to be secured by 2012, for 2016 earliest operation. If, by early 2007, commercialization of coal gasification technology has not progressed as forecast, the plan calls for a contingent option to construct 400 megawatts of conventional coal generation to be secured by 2010 for mid-2013 earliest operation.

The purpose of this paper is to assess the current status of coal-based power generation technologies, and their cost and performance characteristics, compared to the assumptions used in the development of the Fifth Power Plan. Among the conclusions of this assessment are advanced (super-critical) steam-electric coal technologies are entering the market more rapidly than anticipated, the capital cost assumptions for steam-electric technologies remain reasonable, cost assumptions for integrated gasification combined-cycle (IGCC) power plants should be increased to account for the spare gasifier currently needed to achieve the operating availability expected of future baseload power plants, operating availability assumptions for all new baseload coal technologies should be increased for consistency with current practice, availability of petroleum coke fuel for gasification plants should be considered, the thermal efficiency of IGCC plants will be lower than assumed and the efficiency of supercritical steam-electric plants will be higher than assumed.

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[1] Petroleum coke is a by-product residual carbonaceous material from the thermal cracking of heavy residual oils during the petroleum refining process. High grade petroleum coke is used for electrodes for electric steel furnaces. Low grade coke is used for manufacturing electrodes for aluminum production and for fuel. Because of the increasing use of heavier crudes and more efficient processing of refinery residuals, US and worldwide production of petroleum coke is growing rapidly. Petroleum coke has a superior heating value (13,460 Btu/lb) and very low ash content compared to coal. This reduces transportation costs. However, depending on the original crude feedstock, it may contain a greater concentration of sulfur and metals, making it a less attractive fuel when burned in conventional boilers. Historically, petroleum coke has been priced at a discount to coal.

[2] A coal gasification plant designed to produce, electricity, synthetic natural gas or synthetic liquid fuels or other products, or combinations of these. Polygeneration capability increases potential revenues and provides greater operational and financial flexibility.

Technology and Applications

The two basic types of baseload coal-fired power plants are direct-fired (steam-electric) plants and gasification plants. Direct-fired plants combust coal in a furnace to raise steam that drives a steam turbine-generator. Gasification plants convert coal into a synthetic fuel gas by a partial combustion process. The synthetic gas fuels a combined-cycle gas turbine generator. Both types of plants would be used primarily to supply base load power, though the gasification plant offers the potential for greater operating flexibility. Earlier assessments forecast the thermal efficiency of an integrated gasification combined-cycle (IGCC) plant to be clearly superior to that of direct combustion plants. More recent studies indicate that advanced direct combustion plants using supercritical steam conditions may have efficiencies approaching that of IGCC plants.

Coal gasifiers can utilize biomass and petroleum coke (pure or blended), though the prospective fuels need to be considered in the design of the plant. Direct-fired plants can also be designed for co-firing of biomass and other fuels.

Gasification technology employs pre-combustion cleanup of the synthetic gas stream. This can result in very low air emissions if the necessary cleanup equipment is installed. However, recent advances in emission control technology for direct-fired plants can reduce the air emissions of these plants to levels comparable to gasification plants. Perhaps the greatest advantage of gasification plants is that they can be equipped with relatively proven technology for partitioning carbon dioxide from raw synthetic gas, for subsequent sequestering of the CO_2. Partitioning CO_2 from the post-combustion gases of a direct-fired plant is possible, but in a much earlier stage of development.

Advanced, supercritical direct-fired steam plants are an evolutionary technology, basically being a much higher-pressure version of a conventional steam-electric plant. Early (1960s) supercritical designs proved unreliable because of material failures. Better materials have improved the reliability of these plants and numerous supercritical units are operating in Europe and several are under construction in North America. Gasification technology, while widely used in the petrochemical industry for production of organic chemicals from coal and refinery residues, has not been widely used for power generation. Nor is there much experience gasifying low-rank western coals. Operating availability is a particular concern. Demonstration plants constructed in the 1990's encountered multi-year shakedown period of low availability, though these plants are reported now to operate reliably. Periodic replacement of the refractory lining of the gasifiers is needed, a process requiring several weeks. To maintain adequate availability for power generation, proposed gasification power plant designs now incorporate spare gasifiers.

Cost and Performance Assumptions

Key Fifth Power Plan planning assumptions for coal-fired power plants are shown in the following table. Project output and costs are based on ISO conditions.[3] Costs are adjusted to 2006 dollars for better comparability to current conditions. Heat rates and costs are normalized for 2010 service.

[3] Sea level, 59°F. Output and costs were adjusted for higher elevation situations in the 5th Plan analyses.

	Direct-fired Subcritical	**Direct-fired Supercritical**	**IGCC (w/o CO_2 Partitioning)**	**IGCC (w/ CO_2 Partitioning)[4]**
Type	400 MW sub-critical pulverized coal-fired, evaporative cooling. Low-NOx burners, flue gas desulfurization, fabric filter w/ activated charcoal injection	400 MW supercritical pulverized coal-fired, evaporative cooling. Low-NOx burners, flue gas desulfurization, fabric filter w/ activated charcoal injection.	425 MW integrated gasification combined-cycle; sulfur stripping unit, activated carbon Hg removal, H-class gas turbine generator.	425 MW integrated gasification combined-cycle; sulfur stripping unit, activated carbon Hg removal, shift reactor & CO_2 stripping unit (90%); F-class gas turbine generator
Net Output	400 MW	400 MW	425 MW	401 MW
Availability	84%	84%	83%	83%
2004 Commercial status	Mature	Emerging Commercial	Demo (F-class GTG) Conceptual (H-class GTG)	Conceptual
Heat Rate[5] (Btu/kWh)	9426	9070	7813	9170
Capital cost ($/kW)[6]	$1435	$1457	$1617	$2079
Fixed O&M cost ($/kW/yr)	$46	$47	$52	$61
Variable O&M cost ($/MW)	$2.00	$2.00	$1.70	$1.80
Development and Construction Schedule	36/42	36/42	36/48	36/48
Earliest service (greenfield site)	2011	2011	2011	2011

Subcritical and supercritical plants were not modeled separately in the Fifth Plan. Rather, they were modeled as a single pulverized coal steam electric technology that improved over time as the penetration of supercritical plants increased. This was assumed to increase the average new plant efficiency by 0.25% annually and also to increase fixed costs by 0.1% annually because of the higher cost of materials required for supercritical designs.

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[4] CO2 compressed to critical state at plant fence, no CO2 transportation or sequestration.
[5] ISO, higher heating value, new and clean.
[6] Overnight cost, 2006 dollars.

The gasification plant without CO_2 separation capability was the technology used in the Fifth Plan portfolio analysis. The efficiency of gasification plants was assumed to increase by 0.5% annually, and fixed costs were assumed to decline by 0.5% annually through improvements to gasification and gas turbine technology.

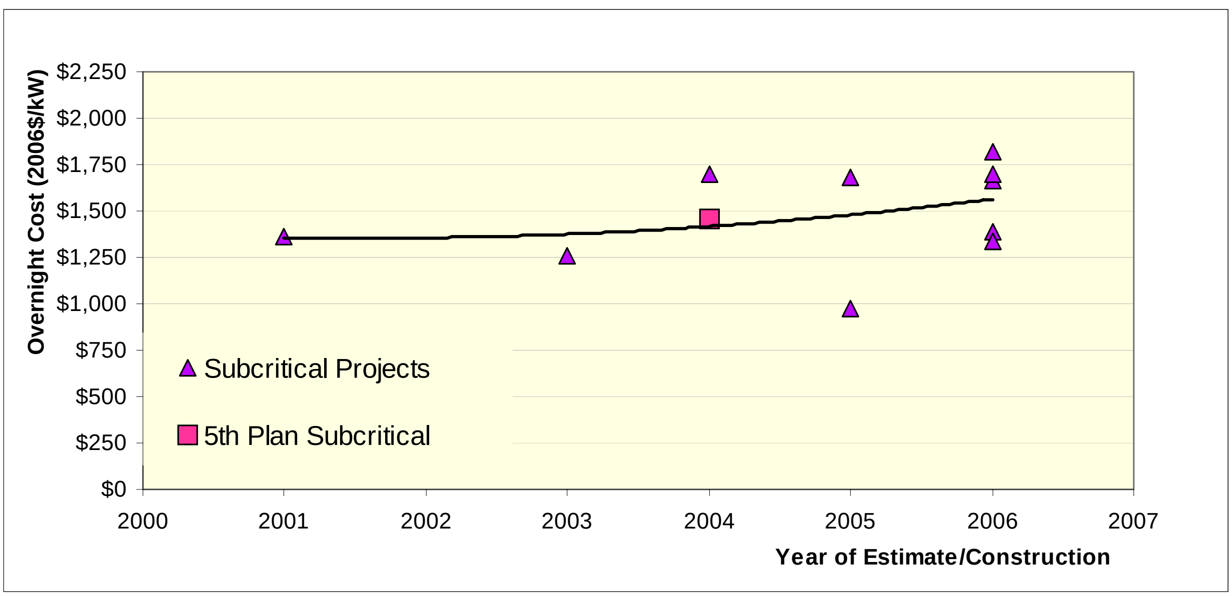
Review of Cost and Performance Assumptions

Significant factors affecting the cost-effectiveness of coal-fired power plants include capital cost, thermal efficiency and operating availability.

Capital cost of direct-fired subcritical power plants

The Fifth Power Plan capital cost assumption for direct-fired subcritical power plants are compared in Figure 1 to announced project costs taken from a data base maintained by the Council, and to recent estimates prepared for the U.S. Environmental Protection Agency and for PacifiCorp. For completed projects and projects under construction, the horizontal axis represents the initial year of construction; for estimates and proposed projects, the horizontal axis represents the year of the estimate. The vertical axis represents "overnight" capital cost[7] in 2006 dollars. The "Subcritical project" series (triangles) are per-kilowatt capital costs, normalized to the definition of overnight costs used in the Fifth Plan. Relatively few coal-fired power plants have been constructed in recent years, leading to the small sample size, even though interest in coal is currently high. Somewhat higher costs are evident for the more recent data points, suggesting the possible effects of recent increases in materials cost.

Figure 1
Direct-fired subcritical power plant capital cost estimates



[7] "Overnight" cost is the total construction cost less costs of financing, escalation and interest during construction.

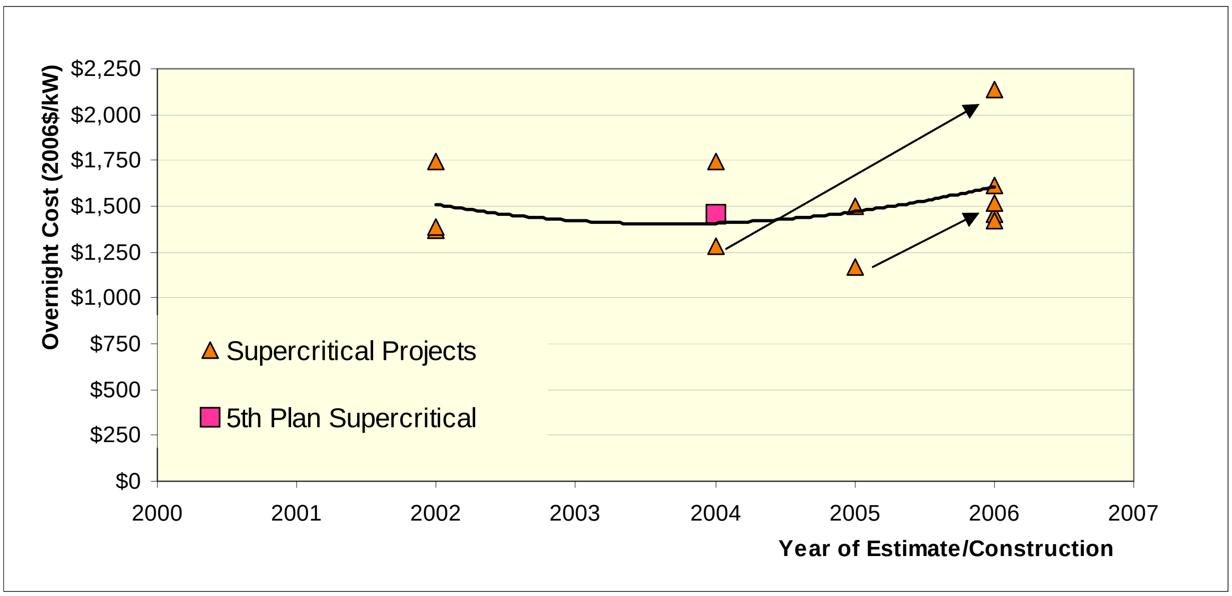
The Fifth Plan cost estimate are shown as the 2004 box. While slightly lower than the average of the 2006 points, the 5th Plan assumption appears to remain reasonably representative of expected long-term market conditions.

Capital cost of direct-fired supercritical power plants

Figure 2 compares capital costs for supercritical steam cycle plants. As before, the recent upturn in costs due to increasing materials costs is evident. The arrows in Figure 2 indicate two examples where plant costs were recently re-estimated as the projects moved forward. Significant cost increase occurred in each case, partly because of refinement and modification of project design, but also because of increasing materials costs.

The Fifth Plan cost estimate is shown as the 2004 box. As before, while slightly lower than the average of the 2006 points, the 5th Plan assumption appears to remain reasonably representative of expected average long-term market conditions.

Figure 2
Direct-fired subcritical power plant capital cost estimates

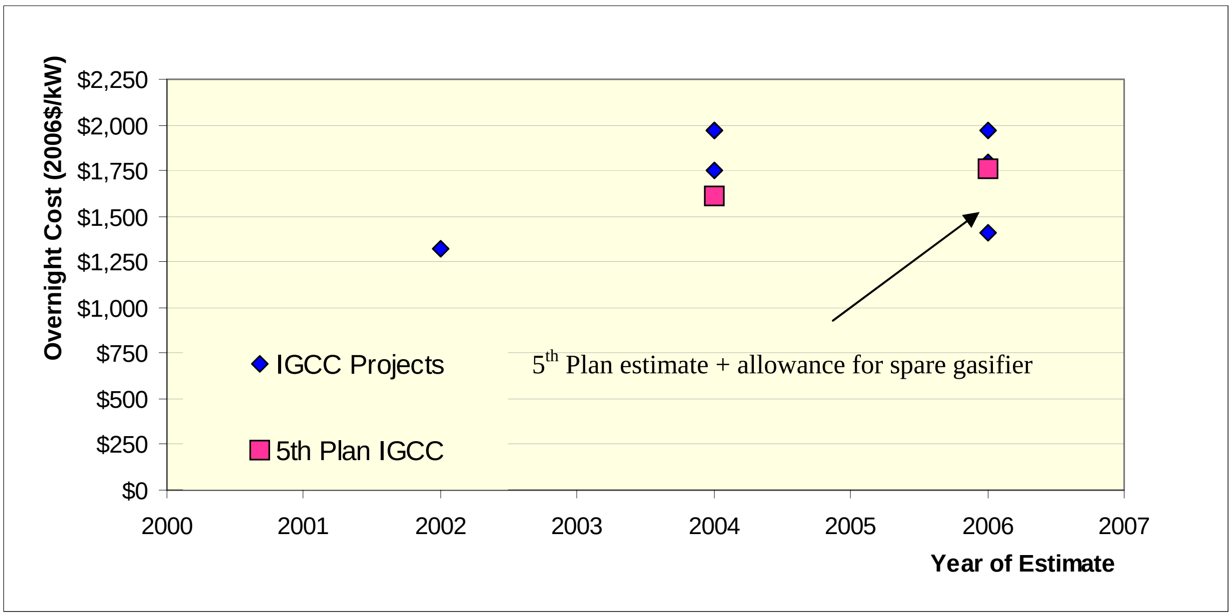


Capital cost of coal gasification combined-cycle power plants

Figure 3 compares capital costs for integrated gasification combined-cycle power plants. These are plants without provision for CO_2 separation, though that capability could be retrofitted subsequent to initial completion. (This is the plant configuration used in the Fifth Plan portfolio analysis.) A general upward cost trend is evident. Though increasing materials costs are a contributing factor, the trend in the case of IGCC plants is also due to more accurate estimates resulting from better definition of plant requirements. (Typically, the costs of emerging power generation technologies are underestimated prior to their actual deployment). Specifically, several recent estimates have included a spare gasifier in order to achieve design plant availabilities in the 90 percent range. In addition, the higher cost 2004 and 2006 examples are for high-elevation plant sites. Gas turbine and air separation plant output decline as site elevation increases because of the additional compressive work required in the lower density ambient air. This increases the per-kilowatt cost of these plants.

The Fifth Plan IGCC cost estimate is shown as the 2004 box. A second box is shown at 2006 representing the Fifth Plan estimate adjusted for the additional cost ($100 - 200/kW) of a spare gasifier to achieve plant availabilities in the 90 percent range. Though comparable to the higher 2006 estimates, the resulting estimate may be slightly high since the Plan assumption is intended to represent a low-elevation site and equilibrium market conditions.

Figure 3
Coal gasification combined-cycle power plant capital cost estimates



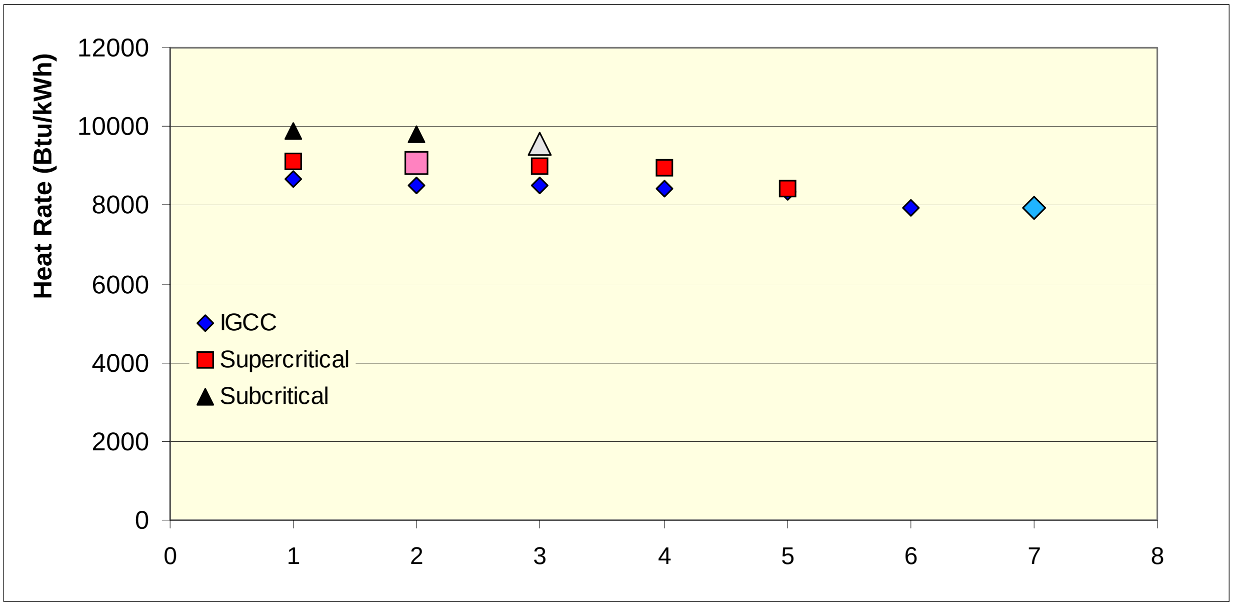
Efficiency of coal-fired power plants

As the engineering of coal gasification power plants has advanced in recent years, moving from generic to standardized, coal-specific and site-specific designs, it has become evident that the thermal efficiency of these plants was overestimated in earlier studies. Plotted as blue diamonds in Figure 4 are design and estimated heat rates of IGCC plants. The vertical axis of Figure 4 is heat rate, a measure of the amount of fuel consumed per kilowatt-hour produced. Heat rate is the inverse of thermal efficiency, i.e., as heat rate declines, thermal efficiency increases. The large pale blue diamond to the right represents the Fifth Plan assumption. This estimate, based on studies conducted about year 2000, is representative of earlier studies, is the lowest of the samples. The higher heat rate values to the left are more representative of the design values of current engineering studies. This suggests that the Fifth Plan efficiency assumption for IGCC plants should be increased about 7 percent from 7915 to 8000 Btu/kWh.

The Fifth Plan assumption regarding the heat rate of direct-fired supercritical units, also plotted in Figure 4 (large pink square compared to red squares) appears to underestimate the efficiency of this technology. The plot suggests that the Fifth Plan efficiency assumption for IGCC plants should be lowered about 2 percent from 9070 to 8900 Btu/kWh. Finally, the Fifth Plan estimate of the efficiency of direct-fired subcritical units (Large gray triangle among black triangles in Figure 4) appears to be somewhat optimistic. A 3 percent increase in the assumed heat rate of subcritical units, from 9550 to 9850, appears to be in order.

These changes to heat rate assumptions may appear minor, but in practice can significantly affect the comparative economics of the technologies. The result of these changes is to establish clearly superior economics to supercritical direct fired units compared to subcritical units, and to narrow the fuel cost gap between direct-fired super critical plants and IGCC plants.

Figure 4
Coal-fired power plant efficiency estimates



Conclusions

The role of coal-fired generation and of the various coal technologies is in ferment. Supercritical steam-electric technology is superceding conventional subcritical technology in the North American market. Commercialization of gasification plants lags that of supercritical plants, but is also advancing. Though currently at an overall cost-of-power disadvantage compared to super critical plants, particularly at high elevation locations, gasification plants retain clear advantages including the potential for polygeneration, commercially-available technology for separation of CO_2, somewhat superior air emission control and less water consumption.

Refinement of IGCC designs has led to the frequent inclusion of a spare gasifier, at increased cost, to achieve the 90% level of availability now expected of baseload plants. Refinement of IGCC designs has also resulted in lower estimates of thermal efficiency for first generation commercial plants.

The Fifth Plan assumptions regarding baseload coal-fired plant availability (~85%) are lower than current expectations (~90%).

Fifth plan capital cost estimates for direct-fired plants (sub- & supercritical) remain reasonable, however the estimates for IGCC plants should be increased to account for a spare gasifier.

Increased availability of petroleum coke, and the availability of commercial coke-fired IGCC technology has created the opportunity for clean plants at Westside locations using low-cost solid fuel.

Capital costs of all coal-fired technologies in the near-term are probably somewhat high because of the increased cost of materials. The Fifth Plan estimates are intended to be representative of loner-term equilibrium market conditions.

The Fifth plan assumptions of coal-fired power plant thermal efficiencies should be revised. IGCC assumptions are about 8% high and direct-fired subcritical assumptions about 3% high. Supercritical assumptions are about 2% low.

"CO_2 removal ready" (CRR) IGCC plants that incorporate the oversized gasification and air separation equipment necessary to ensure the material balance of the retrofit plant may cost about 10 percent more than plants that only reserve space for future retrofit. Future revisions to the power plan should consider this option.

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Other Generating Technologies

The purpose of this paper is to assess recent developments regarding new electric power generating resources for use by the Pacific Northwest and the possible significance of these developments to the Fifth Northwest Electric Power and Conservation Plan. The focus is on developments occurring since adoption of the Fifth Plan. For completeness, this paper summarizes the findings of the assessments of coal, natural gas and wind power, covered in more detail in specific papers.

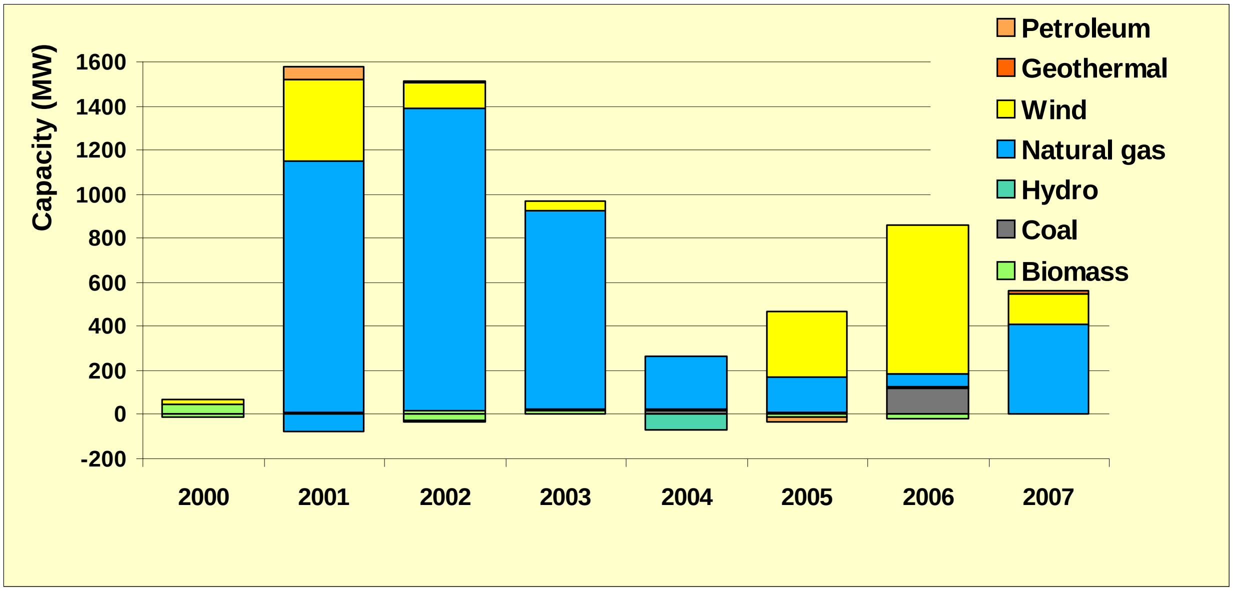
The paper begins with an overview of generating resource development since adoption of the Fifth Plan. This is followed by an assessment of changes to the commercial status, cost or performance of the litany of new generating resource options. The paper concludes with a summary table of key developments, their significance and possible Council responses.

Resource Development Activity

A new cycle of resource development has occurred since adoption of the Fifth Plan (Figure 1). The Plan foresaw little need for new capacity prior to 2010, and recommended no major resource acquisitions other than 500 megawatts of wind to help confirm the resource potential. However, nearly 1900 megawatts of new capacity primarily wind and natural gas has entered service or is are under construction since adoption of the Plan. Wind plant construction is driven by extension of the federal production tax credit, the California renewable portfolio standard and high natural gas prices. Current thinking is that the wind production tax credit is likely to be extended, possibly for several years, but at a declining rate. In combination with the aggressive 2010 target of the California, this will likely lead to a continued rapid rate of wind power development in the Northwest. A preliminary estimate prepared for the Northwest Wind Integration Action Plan project is for 1200 to 2200 megawatts of wind power development from 2007 through 2009.

The natural gas capacity additions shown in Figure 1 were under construction at the time of Plan adoption. An additional 170 megawatts of natural gas capacity for serving growing peaking capacity is planned for 2008. The coal resource appearing in 2006 is the 116-megawatt Hardin plant, located in eastern Montana.

Figure 1
Pacific Northwest electrical generating capacity additions



Resource Status and Recent Developments

Biomass

Biomass generation currently represents about two percent (900 megawatts) of Northwest generating capacity. Though opportunities for expansion are diverse, the relatively high cost of new biomass capacity has resulted in only about 15 megawatts of new biomass generation since adoption of the Fifth Plan. The most feasible near-term uses of biofuels for electric power generation in the Northwest are expected to be landfill gas energy recovery, wastewater treatment plant and animal manure energy recovery and chemical recovery boiler upgrades. Other possible sources of biofuels include forest thinnings, agricultural field residues, municipal solid waste and energy crops. While available in large quantities in the Northwest, the high cost of generation using forest thinning residues may continue to constrain further development of this resource. It is possible that the development of processes for economically producing ethanol form cellulosic waste may divert forest residues to this application. Likewise, ethanol production may ultimately be the most economic use of agricultural field residues. Public opposition, high cost, and established municipal solid waste (MSW) disposal systems are likely to retard development of energy recovery from raw MSW. Much of the energy value of MSW, however, can be recovered by separating the clean combustible fraction for use as fuel. Though technically feasible, the estimated cost of producing electricity from dedicated hybrid cottonwood exceeds \$100/MWh. The wood is more valuable as a fiber crop.

The most significant development regarding biofuels since adoption of the Fifth Plan has been acceleration of efforts to derive synthetic liquid fuels from energy crops and biomass residues. Development of economic processes for converting cellulosic waste to ethanol could divert the fairly large bio-residue potential to liquid fuel production.

Coal

Coal-fired power plants represent about 14 percent (7560 megawatts) of Northwest generating capacity. Most of this capacity consists of large central station units completed between 1968 and 1986. Low coal prices, mature technology, limited availability of natural gas and nearly complete development of low-cost hydropower made coal a "resource of choice" during this period. Rising natural gas prices has renewed interest in coal-fired generation throughout North America. However, the choice of coal technology, fuel and site has become more complex. An array of technologies, carbon dioxide (CO_2) control policy, availability of petroleum coke, co-production options[1], mercury control, federal incentives, water and transmission availability and public perception all meld in the choice of coal technology, fuel and site. It is becoming evident that no single correct choice of technology or configuration exists for all situations.

The current status of coal-based generation is assessed in the paper *Assessment of Coal-fired Power Plant Planning Assumptions*. That assessment found: (1) advanced (super-critical) steam-electric coal technologies are entering the market more rapidly than anticipated; (2) the Fifth Plan capital cost assumptions for steam-electric technologies remain reasonable; (3) cost assumptions for integrated gasification combined-cycle (IGCC) power plants should be increased to account for the spare gasifier needed to achieve the availability expected of base load power plants; (4) availability assumptions for new coal technologies should be increased; (5) petroleum coke is becoming increasingly available as a fuel option for gasification plants; and (6) the efficiency of IGCC plants will be lower and the efficiency of supercritical steam-electric plants will be higher than previously thought.

Geothermal

The heat of the earth is naturally concentrated as hot water at certain near-surface locations, from which it can be economically captured and converted into electricity. Potential geothermal resource areas in the Northwest include deep vertical faults in the Basin and Range geological province in southeastern Oregon and Southern Idaho and shallow magmatic intrusions associated with Cascades vulcanism. Basin and Range geothermal resources have been developed for both power generation and for direct application in Nevada, Utah and California. The 13-megawatt phase I of the Raft River project in southern Idaho, when completed in 2007 will be the first commercial geothermal power plant in the Northwest.

Newberry Volcano, Oregon and Glass Mountain, California are the only Cascades structures offering geothermal potential not largely precluded by land use. Geothermal potential has been confirmed at Glass Mountain. Though projects have been proposed for these sites over the years, none have yet come to fruition. Overall Northwest geothermal potential is poorly understood. The estimate of the Fourth Power Plan, 340 to 3300 average megawatts with a most likely potential of 940 average megawatts, remains reasonable.

Only dated and uncertain geothermal cost information was available for the Fifth Plan. Because of this, and the uncertainty regarding Northwest potential, geothermal was not specifically included in the portfolio analysis. The developers of the Raft River project have recently

[1] Co-production is the manufacture of electricity, hydrogen, and substitute natural gas, synthetic liquid fuels and other products from a common plant.

published generic cost information that could be used to update the Council's estimates of geothermal cost and provide a sounder basis for considering geothermal in future portfolio analyses.

Hydropower

Though hydropower represents about 64 percent (33,560 megawatts) of Northwest generating capacity, most feasible sites have been developed. The remaining opportunities are for the most part small-scale and relatively expensive. In its Fourth Plan, the Council estimated that new sites might yield about 480 megawatts of additional hydropower capacity at $90 per megawatt-hour, or less. This capacity could produce about 200 average megawatts of energy. Some additional energy is available from upgrades to existing projects. The Council retained this estimate for the Fifth Plan, and concluded that few projects are expected to be constructed because of the high cost of developing most of the remaining feasible sites and the complex and lengthy licensing process. Overall, it appears unlikely that new hydroelectric development will be able to offset the loss of capacity and energy from expected removal of several older environmentally damaging projects.

The conclusion has largely been borne out. Three projects, totaling 25 megawatts of capacity have been brought into service since adoption of the Fifth Plan and no additional projects are currently under construction. While new hydropower is unlikely to become a major contributor to new resource needs, newer information is available regarding undeveloped hydropower potential. The Idaho National Laboratory (INL) as part of a nationwide assessment has identified 1315 sites in the four-state region with an undeveloped potential exceeding 8000 megawatts. Though it is not clear that this survey fully considered all constraints to development faced by new hydropower in the Northwest, the INL survey employed methods and information not available when the surveys upon which the Council's estimates are based were undertaken in the 1980s. A revised estimate of new Northwest hydropower potential could be prepared for the next power plan using the INL survey and other, more recent information.

Natural Gas

Natural gas combined-cycle power plants represent about 11 percent (5914 megawatts) of Northwest generating capacity. Simple-cycle units, valued for system reliability, regulation, load following and hydro firming, comprise about 3 percent (1654 megawatts) of Northwest generating capacity. Most of the combined-cycle capacity was completed between 1995 and 2004 when low natural gas prices and reliable, low-emission and efficient gas turbine technology made these plants the resource of choice. Higher natural gas prices have reduced the attractiveness of bulk power generation using natural gas and construction of only one large combined-cycle project has been initiated since 2001. That plant is the 399-megawatt Port Westward project, scheduled for completion in 2007.

The current status of natural gas power generation technologies are assessed in Appendix E - Gas Turbine Power Plant Assumptions. That assessment found: (1) the Fifth Plan assumptions regarding cost and performance of natural gas power plants remain representative of real-world experience; (2) possible needed capacity to maintain system reliability, and regulation and load following capability for the integration of wind power may result in the need for additional natural gas capacity prior to that identified in the Fifth Plan; (3) completion of currently suspended combined-cycle capacity may become attractive in the face of the cost increases being experienced for other new generating resources; and, (4) in view of the strongly cyclical market observed for natural gas and other new generating resources, future portfolio analyses might consider possible correlations between electricity market activity and resource capital costs.

Nuclear

At the time the Fifth Plan was prepared, future U.S. nuclear plants were expected to use advanced "Generation III+" designs such as the Westinghouse AP-1000. These are completely new designs employing passively-operated safety systems and factory-assembled standardized modular components. These features are expected to result in improved safety, reduced cost and greater reliability. In the Fifth Plan, the first North American Generation III+ plants were assumed to be operating by 2015, probably at southeastern sites, following which a decision might plausibly be made to proceed with construction with a new plant in the Northwest. That plant would see service by 2020 at the earliest. Because of the distant decision dates, a new nuclear option was not considered in the portfolio analysis and actions bearing on new nuclear plants were not included in the plan.

The Energy Policy Act of 2005 includes incentives for new commercial nuclear plants including a production tax credit, loan guarantees and insurance against construction delays. These incentives, plus high natural gas prices and greenhouse gas risk have motivated developers, mostly operators of existing nuclear facilities in southeastern United States to seriously consider construction of new nuclear capacity. As of August 2006, the Nuclear Regulatory Commission has received notices of interest for 27 potential new commercial nuclear projects. One, Constellation Energy has proceeded to order heavy components, but not for a Generation III+ plant. The components are for an enlarged (1600 megawatt) Generation III "evolutionary" design, an example of which is under construction in Finland. Another developer, NRG, has announced its intention to apply for a two-unit operating license for another evolutionary design, the General Electric Advanced Boiling Water Reactor, similar to units operating in Japan since 1996 and currently under construction in Taiwan. Generation III plants are refined versions of the current generation of nuclear plants. These developments suggest that the next U.S. plants will likely be evolutionary designs, rather than the full passively safe modular designs formerly thought to represent the next generation of U.S. plants.

The assumption that the earliest decision to proceed with construction of a new nuclear power plant in the Northwest would come no sooner than 2015 remains reasonable. Cost and performance assumptions for Generation III and III+ units and the proposed hydrogen co-production demonstration reactor at INL should be included in the next plan.

Ocean and Tidal Currents

The kinetic energy of flowing water can be used to generate electricity by turbines operating on similar principals to wind turbines, but more compact because of the greater density of water. Turbine energy yield is very sensitive to current velocity and little potential is available from the weak and ill-defined currents off the Northwest coast and in the Strait of Juan de Fuca. However, tidal currents of 3 to 8 knots occur locally in Puget Sound and estuaries along the Oregon and Washington coast could provide an economic source of energy as Tidal In-Stream Energy Conversion (TISEC) devices are perfected. A prototype machine was deployed at Race

Rocks in British Columbia in September and the deployment of the first two turbines of a six turbine pilot plant in New York City's East River is planned for November. Twenty-nine requests for preliminary permits have been filed with the Federal Energy Regulatory Commission, including sites in the Tacoma Narrows, Deception Pass and the San Juan Islands. A feasibility study of the Tacoma Narrows site concluded that a commercial project could yield about 16 average megawatts at $72 to $90/MWh (2005 dollars, including federal production tax credit). Commercialization of this resource will require development and production of TISEC machines suitable for extended reliable and efficient operation under fully-submerged conditions. Other issues needing resolution include system integration, environmental impacts, installation and maintenance procedures, cost uncertainties and public acceptance. Though the potential Northwest resource would be of limited size (tens to low hundreds of average megawatts), TISEC plants would have predictable though intermittent output, low aesthetic profile and could provide local distribution system support. The resource should be more fully assessed in the next power plan. The current plan contains an action (GEN-17) supporting the development and commercialization of new renewable technologies such as wave power and TISEC.

Ocean Thermal Gradient

An ocean thermal energy conversion (OTEC) power plant extracts energy from the temperature difference that may exist between surface waters and waters at depth. Megawatt-scale OTEC technology has been demonstrated in Japan and Hawaii, but practical application of the technology requires a temperature differential of about 20^{o} C (36^{o}F), or greater. Temperature differentials of this magnitude are limited to tropical regions extending to 25 to 30 degrees of latitude. Ocean thermal temperature differentials in the Northwest range from 0 to 12^{o}C (0 - 20^{o}F) precluding operation of OTEC technology.

Petroleum

Petroleum-derived fuels such as propane, distillate and residual fuel oils are too costly for bulk electric power generation in the Northwest. Distillate fuel oil and propane are used as backup fuel, plant startup, for peaking or emergency service power plants and for power generation in remote areas. About 90 megawatts of capacity primarily fuelled by petroleum fuels are in service in the region.

Petroleum coke ("pet coke") is a solid carbonaceous residual product produced by thermal decomposition (cracking) of heavy residual oils during refining. This product consists mostly of carbon and small amounts of hydrocarbons, sulfur and ash and trace quantities of metals. Increasing use of heavier crudes and more efficient processing of refinery residuals has resulted in rapid growth in US and worldwide production of petroleum coke. Additional supplies are becoming available from Alberta oil sands synthetic crude production. Green coke[2] can be used directly as fuel, or further processed for use as a raw material for the manufacture of electrodes for the smelting of metals. A 65-megawatt cogeneration project at the Exxon Billings refinery uses petroleum coke as fuel.

[2] Coke directly from refinery coking units.

Petroleum coke has a superior heating value compared to lower-rank coals and a very low ash content. However, most of the sulfur, inert materials and heavy metals present in the crude feedstock are concentrated in the coke, making it an environmentally unattractive fuel for conventional boilers. For this reason, petroleum coke has historically been priced at a discount to coal. An attractive approach for recovering the energy value of coke is to convert it to a synthetic fuel gas in a gasification plant. The sulfur can be removed from the raw synthesis gas using standard processes. Metals are embedded in the gasifier slag or removed in the syngas coarse particulate removal and scrubbing process. Some refineries now employ gasification plants to process coke into higher value products. Since release of the Plan, Energy Northwest has proposed constructing a 600-megawatt gasification combined-cycle power plant at Kalama on the lower Columbia River. The plant would use petroleum coke from Puget Sound refineries possibly in combination with other coke and coal supplies as feedstock.

Because of the increasing availability of petroleum coke and the availability of gasification technology to use this fuel, a forecast of the future price and availability of petroleum coke should be added to the next power plan.

Salinity Gradient Energy

Energy is released when fresh and saline water area mixed. Conceptually, the energy potential created by fresh water streams discharging to salt water bodies could be captured and converted to electricity. The technologies to do so are in their infancy, and it is not clear that current concepts would be able to operate off the natural salinity gradient between fresh water and seawater as present at the mouth of the Columbia and other rivers. Although the theoretical resource potential in the Northwest is substantial, many years of research, development and demonstration would be required to bring these technologies to commercial availability.

Solar

The best solar resource areas of the Northwest - the inter-mountain basins of south-central and southeastern Oregon and the Snake River plain of southern Idaho - receive about 75 percent of the solar energy received at the best Southwestern sites. However, because of latitude and climate, the Northwest solar resource exhibits strong summer seasonality. While desirable for serving local summer-peaking loads, the Northwest resource is not coincident with general regional loads. There has been no regional assessment resource potential, though it is likely there is sufficient developable resource to support any feasible demand[3].

The use of small photovoltaic arrays to generate electricity is widespread and has been encouraged in the Northwest by state incentive programs. While economic for small isolated loads, bulk photovoltaic power is currently much more expensive than power from competing sources. The present-day cost of bulk power from photovoltaics was estimated in the Fifth Plan to be $250 per megawatt-hour, compared to $33 - 46 per megawatt-hour for other bulk power sources. Photovoltaic costs have historically declined at about 8 percent per year on average and capacity addition studies using the AURORA model suggested that bulk photovoltaic generation might become economically competitive in the Northwest about 2025 (and sooner in the Southwest) if this rate of cost reduction was sustained. Strong demand and increasing material

[3] An assessment developed by the Western Governor's Association Clean and Diversified Energy Initiative was limited to the deployment of central station solar thermal plants in the Southwest.

costs have recently reversed the declining trend in photovoltaic prices. Module prices rose three percent in real terms between 2004 and 2005, though this is a modest increase compared with cost increases incurred by many other generating resources. Over the long-term, increasing demand should lead to increasing economies of production. Also, technology developments promise more efficient use of materials. These factors should lead to continued decline of photovoltaic costs over the long-term.

Solar thermal technologies employ concentrating devices to create temperatures suitable for driving thermal engines. Concentrating thermal technologies are currently less costly than photovoltaics for bulk power generation. They can also be provided with energy storage or auxiliary boilers to allow operation during periods when the sun is not shining. Concentrating solar thermal technologies require high levels of direct normal solar radiation for most efficient operation and are best suited for Southwest conditions. Over 350 megawatts of concentrating solar thermal capacity was constructed under favorable contracts in California during the 1980s. Following a 15-year hiatus, a one-megawatt plant was recently completed by Arizona Public Service Company. A much larger (65-megawatt) plant is under construction in southern Nevada.

Fifth Plan assumptions regarding solar generation remain consistent with long-term expectations.

Tidal Energy

Tidal energy can be captured and converted to electricity by means of hydroelectric “barrages” constructed across natural estuaries. These admit water on the rising tide and discharge water through hydro turbines on the ebb. The key requirement is a large mean tidal range, preferably 20 feet or more. Suitable sites with tides of this magnitude occur only in a few places worldwide where landforms amplify the tidal range. Economic development of tidal hydroelectric plants in the Northwest is precluded by insufficient tidal range.

Wave Energy

Three wave energy projects have been proposed in the Northwest. Each would initially consist of a small demonstration array of wave energy converters. These could be expanded to commercial-scale if the technology and site proves feasible. Though the technology is still in the pre-commercial stage, wave energy could be a major player in the Northwest. The theoretical wave power potential of the Washington and Oregon ocean coast is estimated to 3,400 - 5,100 megawatts for near-shore sites and 21,000 megawatts for offshore sites. Wave power converters are expected to have an efficiency of at least 12 percent, suggesting a technical potential of up to 2,500 megawatts, though only a portion of this potential is likely to be available because of navigational, aesthetic or ecological concerns. Wave power in the Northwest is winter peaking with a seasonal factor of 20. While the Council concluded that it is unlikely that commercial wave power projects will become widespread during the period of the Fifth Plan, development of the technology is accelerating and a full review of wave power cost and technical potential should be prepared for the next plan.

Wind Power

With completion of projects under construction, wind power will have grown to about 3 percent of regional capacity (1730 megawatts) for zero ten years ago. Factors contributing to the recent acceleration in the growth rate of wind include sustained high natural gas prices, climate change concerns, the federal production tax credit (PTC), and state renewable portfolio standards (RPS). Adoption of proposed RPS for Washington and Oregon would sustain current rates of development. For the Fifth Plan, the Council assumed 6000 additional megawatts of wind potential consisting of 1000 megawatts of committed resource and 5000 megawatts of discretionary resource. All 5000 megawatts of discretionary wind capacity were included in the recommended resource portfolio. The action plan recommended near-term development of 500 megawatts of wind power to resolve uncertainties associated with large-scale development of the resource. Actual development has greatly exceeded this recommendation.

Earlier this year, in response to Bonneville and utility concerns regarding significant cost increases, the Council released the paper *Assessment of Near-term Wind Power Plant Planning Assumptions*. That assessment found a 50 to 60 percent increase in wind project capital cost over the past four years principally from increased commodity and energy costs, a weak dollar and escalating demand for wind power equipment and services. These factors have been offset to some extent by higher capacity factors and somewhat more favorable financing. The focus of the paper was on short-term costs and the long-term persistence of higher costs was not addressed. Long-term effects are uncertain. Commodity and energy costs are historically cyclical and are likely to decline over the next several years as global production capacity is increased, substitutes introduced or currently strong demand weakens. A significant unknown is continuation of strong economic growth in East Asia.

A prolonged weak dollar should increase investment in domestic wind turbine production capacity, as would long-term extension of the PTC and broader adoption of state renewable portfolio standards. Continued strong demand should also increase the availability of specialized transportation and erection equipment and skilled construction and operating personnel. While political support for the PTC appears to be strong, extension at current levels will increasingly conflict with the federal budget deficit. Immediate termination of the PTC would suppress demand for a period, reducing costs. On net, wind capacity costs may remain high for the next several years, and then resume their historic downward trend. Offsetting this trend may be declining site quality. As better sites are developed, interconnection and integration will become increasingly expensive and wind quality may diminish.

Bonneville, the Council and the region's utilities recently launched the Northwest Wind Integration Action Plan project. The initial phase of this project seeks to improve the understanding of the ability and cost of integrating the wind capacity expected to be developed within the next several years using existing system capabilities. A subsequent phase will identify the most cost-effective means of expanding transmission, load following and regulation capability to integrate the much larger amounts of wind capacity envisioned in the longer-term. The results of the project are expected to become available beginning in early 2007.

Transmission and Remote Resources

The Fifth Plan assessment of Alberta oil sands cogeneration was the first Council assessment of resource potential external to the Region. Though not included in the recommended portfolio, oil sands cogeneration was sufficiently attractive for the Council to recommend that additional study be undertaken of the transmission costs of importing power from remote locations. Since adoption of the Fifth Plan, the Northwest Transmission Assessment Committee (NTAC) of the

Northwest Power Pool has undertaken several scoping studies of major transmission expansion options. Completed studies include Eastern Montana to Northwest load center corridors and Western Canada - Northwest - Southwest corridors. These studies have yielded better information regarding the cost, capacity and possible location of transmission to access remote resources. Assessments undertaken for the Western Governor's Association Clean and Diversified Energy Advisory Initiative have yielded new information regarding the cost and potential of new coal, wind, hydropower, biomass, combined heat and power, geothermal and solar resource potential in the West. The new transmission and resource information will provide the basis for expanding the scope of future Council resource assessments.

Summary of Recent Developments

Table 1 summarizes recent developments and new information regarding new generating resources. For completeness, the findings of the separate papers on coal, natural gas generation and wind power are included here. Items are listed in general order of priority with respect to possible near-term impacts on Plan recommendations.

Table 1
Summary of recent developments regarding new generating resources.

Development	Significance	Possible Council Response	Timing
Better information regarding coal-fired plant availability, efficiency and cost	Timing of coal in resource portfolio; technology recommendations.	Update coal-fired technology availability, efficiency and cost assumptions. Test effects on portfolio	Near-term
Wind development greatly exceeding levels called for in Plan	Sufficiency of integration capability Timing of non-wind resources	(1) Keep Wind Integration Action Plan project on fast track (2) Add assessment of system flexibility[4] augmentation options to plan	(1) Near-term (2) Following completion of Wind Integration Action Plan
Better information regarding wind cost and resource potential, transmission & integration	Role of wind in longer-term; need to secure transmission & integration capability.	Update wind power planning assumptions. Test effects on portfolio.	Following completion of Wind Integration Action Plan
Growing summer peak loads	Possible need for suitable supply or demand-side capacity in addition to energy-driven needs identified in Plan	Broaden assessment of system capacity needs and options	Next power plan
INL assessment of undeveloped hydropower	Possible expansion of estimated potential	Update estimate of new hydro potential	Next power plan
Increasing availability of petroleum coke	Inexpensive feedstock for IGCC plants	Forecast pet coke cost and availability Assess pet coke/IGCC plant cost and performance	Next power plan
Better information regarding remote resources and transmission	Expanded inventory of new resource options	Expand assessment of remote resource options	Next power plan
Notices of intent to license, equipment orders for new nuclear units; proposed co-production reactor at INL	Role of nuclear in longer-term	Update nuclear planning assumptions	Next power plan
Better information regarding cost of "CO2-ready" IGCC plants	Role of coal-fired plants in longer-term	Prepare estimates of the cost and performance of "CO2 ready" IGCC	Next power plan
Wave power demonstration projects	Role of wave power in longer-term	Update wave power planning assumptions	Next power plan
Tidal current power demonstration projects	Future role of tidal current power	Update tidal current planning assumptions	Next power plan

[4] "System flexibility" includes regulation (sub-hourly) and load following (hourly and longer) capability, provided by generating capacity and possibly by demand response measures.

Load - Resource Balance

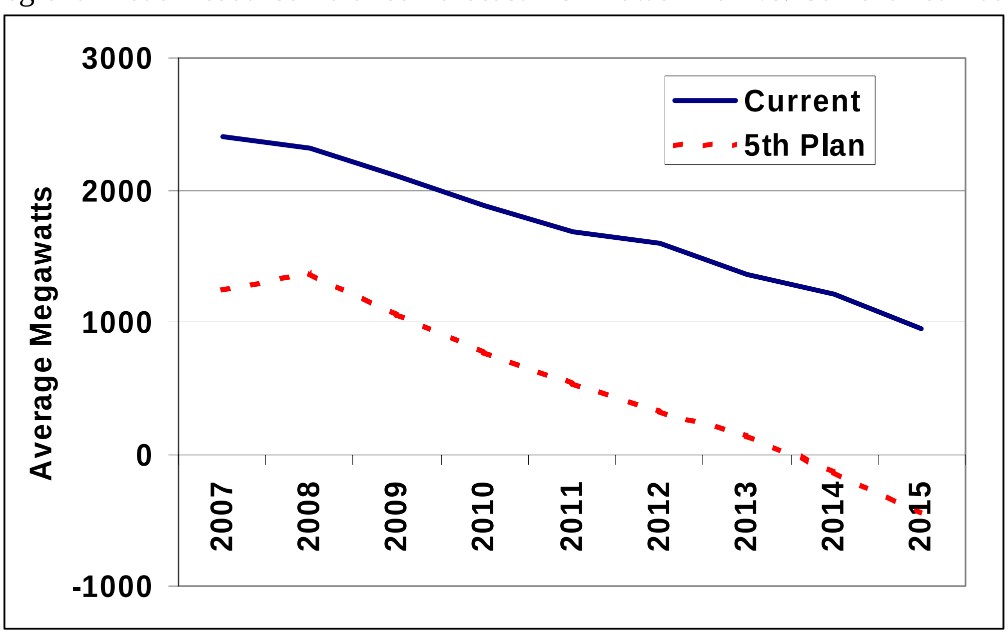
When the Council's Fifth Power Plan was published in 2005, the regional load resource balance was forecast to be about 1,500 average megawatts (MWa), with resources at 23,714 MWa and loads estimated to be 22,181 MWa. That surplus reflects a 6,500 MWa change from the estimated 4,000 MWa deficit in 2000. Most of the increase in the load resource balance was due to the addition of some 4,400 MWa of new resources (a 23 percent increase). The other 1,100 MWa of increase reflects the fact that regional loads had not yet recovered completely from the pre-2001 crisis (still about 5 percent lower than the medium forecast).

The plan projected the 2007 load resource balance to stay at about 1,500 MWa. Current estimates indicate the surplus to be higher than was forecasted for the plan and that it will continue to be higher for at least the next ten years. The current projection for 2007 shows about a 2,400 MWa surplus, with 23,336 average megawatts of net resource and 20,933 average megawatts of load.

It should be noted that the "regional" load resource balance in the plan was actually the balance for the four northwest states. Adjusting that balance to reflect only the region as defined by the Power Act, the plan's forecast of surplus for 2007 becomes about 1,250 MWa, which can be compared directly to the current forecast of 2,400 MWa. About 660 MWa of the 1,150 MWa increase in surplus between the plan estimate and the current estimate is due to Direct Service Industry loads not recovering as projected in the plan. The other 490 MWa increase in surplus is due to new resources (mostly wind) not included in the plan and a somewhat less optimistic forecast for non-DSI load recovery. Figure H-1 compares the current regional load resource balance forecast with the plan's forecast (adjusted to show the regional value instead of the four-state value).

Figure H-1

Regional Load Resource Balance Forecast – 5th Power Plan vs. Current Estimates



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Energy Efficiency

The 5th Plan's Action Plan contained a regional target of 700 average megawatts for conservation resource acquisition from 2005 through 2009 as well as other actions designed to support attainment of that target. Overall the region appears to be making significant progress towards accomplishing the 5th Plans goals, although not all utilities appear to be accomplishing their proportionate share of the savings.

Bonneville, the region's utilities and system benefits administrators have or are accelerating the pace of their conservation programs. Based on preliminary returns to the Regional Technical Forum's (RTF) survey of regional conservation achievements it appears the 5th Plan's goal of 130 average megawatts for 2005 will likely be accomplished. From the survey returns received as of the mid-December the region acquired approximately 130 average megawatts of savings in 2005. The total Bonneville, utility and system benefits charge administrator expenditures for conservation were just over $170 million or about 1.75 percent of total retail revenues collected in that year.

The average utility cost of these savings was approximately $1.3 million per first-year average megawatt saved. This is in the range of costs per first-year savings identified in the Council's Fifth Plan. The cost of conservation acquired is an important factor to track because the system cost and risk benefits of conservation identified in the Council's Fifth Plan are due in large part to the relatively low cost of conservation compared to power purchases or power generation. Unfortunately the RTF survey does not provide information on the levelized cost of conservation which takes into account measure life, and can be compared to the cost of power supplies. Gaining insight on the levelized costs of conservation will require that utilities report measure-level costs and activity.

Savings from Bonneville programs remained roughly constant between 2005 and 2006 producing just over 40 average megawatts each year. Bonneville believes that it has met its share of the region's conservation goal of 52 average megawatts in each of these years since it exceeded its conservation targets in 2003 and 2004. Bonneville believes it is appropriate to count these prior savings towards the 5th Plan's 2005 and 2006 targets. Table 1 shows that with this "carry over" the region's savings for 2005 increase from 129 to 143 average megawatts. Similarly, the projected savings for 2006 increase from 120 to 137 average megawatts. Total regional expenditures to accomplish these savings must also be "carried forward." This increases 2005 expenditures from $170 million to $188 million and projected 2006 expenditures from $170 million to $192 million. This "carry over" has does not provide any additional economic or risk benefits to the region since these savings were already assumed to be "in place" in the current baseline forecast for the Council's Fifth Plan.

Regardless of the treatment of carry over, Bonneville must increase its savings from 40 average megawatts to 52 average megawatts in 2007 if it is to stay on pace to meet the 5th Plan's five year goals. Bonneville implemented its 2007 programs prior to the end of fiscal 2006 in order to sustain utility program activities.

Because final 2006 program accomplishments will not be available for several months it is too early to assess if the Council's target for that year will be achieved. However, from preliminary data available it appears that the region should be able to at least match the savings from 2005.

Table 1 summarizes the annual savings and expenditures for Bonneville, the Northwest Energy Efficiency Alliance (Alliance), and the Energy Trust of Oregon and individual utilities that have responded to the RTF's survey.

Table 1
Summary of Bonneville, Utility and System Benefits Charge Administrator Conservation Achievements (Preliminary)[1]

	2005		Projected 2006	
Program Administrator	**Expenditures (million$)**	**Savings (aMW)**	**Expenditures (million$)**	**Savings (aMW)**
Utility Funded Conservation	$110	77	$120	69
Bonneville Funded Conservation	$40	23	$30	27
Alliance Programs (Utility and Bonneville Funded)	$20	29	$21	25
Total	$170	129	$171	120
Bonneville Funded Conservation (Carry Over)	$17	14	$21	17
Total w/ Bonneville Carry Over	$188	143	$192	137

Market transformation initiatives of the Northwest Energy Efficiency Alliance (NEEA) continue to produce very low cost savings and account for about 20 percent of regional program savings totals. Savings reported by NEEA decreased from 29 average megawatts in 2005 to 25 average megawatts in 2006. This reduction is largely due to changes in federal standards for residential clothes washers that were a target of one of the Alliance's initial market transformation programs. The Alliance is now targeting even higher efficiency machines beyond the federal standards. NEEA market transformation and research activities are limited by its funding.

Although Table 1 shows the quantitative results of conservation implementation in the region, it does not fully capture the changes in national, state and utility policies and activities since the adoption of the Council's 5th Plan. New conservation programs are under development at many utilities, the Energy Trust of Oregon and Bonneville. New research ventures have been initiated and cooperatively funded. Significant progress has been made on regional coordination of conservation efforts. The region leads the nation in adoption of compact florescent light bulbs with 16 percent of all US installations.

[1] Not all of the region's utilities have responded to the RTF's survey. However, the expenditures and savings shown in Table 1 represent 42 entities including Bonneville and the Energy Trust of Oregon and approximately 82 % of the region's load.

Agreements are in place to improve the energy efficiency of small power converters both here in the US and internationally.

At the national level, the Energy Policy Act of 2005 (EPACT 2005) established new federal efficiency standards for 15 new products and requires the US Department of Energy (USDOE) to adopt new or update standards for nine additional products. Perhaps just as significantly, EPACT 2005 also requires USDOE to update over 20 of the existing federal standards and testing procedures that were long overdue for revision -- some by as much as 15 years. USDOE has committed to Congress that it will accomplish this task within the next five years.[2]

At the state level, Oregon and Washington adopted new equipment efficiency standards for 12 of the 15 products covered by the new EPACT 2005 standards. Some of these standards are scheduled to take effect prior to the EPACT 2005 standards. Washington recently adopted revisions to its residential energy code. These revisions are expected to improve the efficiency of new single family and multifamily dwellings by between 7 - 14% depending upon whether the home is located east or west of the Cascades. In early 2007 Oregon will be considering changes to its residential energy code. Governor Kulongoski has set a 15% savings goal for these revisions. Both Idaho and Montana are considering updates to their residential and commercial energy codes as part of their normal code revisions cycles.

These changes in federal and state standards and codes capture only a portion of all of the regional cost-effective efficiency improvements identified in the 5th plan. This occurs for two reasons. First, most of the new federal standards do not become effective until 2007. Second, the efficiency levels of the standards do not achieve all regionally cost-effective savings.[3] Therefore, utility and system benefits charge administrator programs will still be required to secure the remaining cost-effective conservation opportunities.

Since the adoption of the 5th Plan, most of the region's investor-owned utilities and several of the larger public utilities have completed integrated resource planning processes. Staff review of these plans indicates that efficiency investments are increasing. For example, Avista increased its conservation target by 20 percent between 2005 and 2006. Idaho Power Company recently released its 2006 IRP in which it anticipates nearly doubling its annual investment in energy efficiency. Several approaches, including system benefits charges and decoupling mechanisms, are successfully employed or under consideration in the region to reduce regulatory disincentives to utility-based conservation programs.

Washington voters recently passed Initiative 937 (I-937) which calls upon that state's larger utilities to acquire all conservation resources in their service territories that they find to be cost-effective using the Council's methodology. This requirement does not

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[2] See: http://www.eere.energy.gov/buildings/appliance_standards/pdfs/congressional_report_013106.pdf

[3] For example, the recently adopted revisions to Washington's residential code will require windows to achieve a U-factor of 0.35 or lower. The Council's plan identified windows with a U-factor of 0.30 or lower as being regionally cost effective.

take effect until 2010. However, it is anticipated that those utilities covered by I-937 will begin modifying their programs before 2010. Staff believes that the overall impact of I-937 will be to increase local utility conservation acquisitions.

In Oregon, the Energy Trust has had to restrict participation in its programs due to funding limitations. As a result, the Oregon Public Utility Commission and Portland General Electric are now discussing the feasibility of increasing Energy Trust conservation funding. Such funding would be made available from the states investor owned utilities if their integrated resource planning processes find that additional conservation investments would be justified. In is anticipated that legislation concerning this matter will be introduced during the 2007 session.

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Demand Response

The Council took up demand response for the first time in the 5th Power Plan. The plan traced the increasing importance of demand response and recommended actions "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." As part of those actions, the Plan recommended that the region acquire 500 MW of demand response by 2009.

Existing Programs

The region's progress on demand response has been uneven. Utilities have implemented some demand response programs, focusing mainly on those programs that offer close control to the utility. Examples of these programs are the irrigation scheduling programs of PacifiCorp and Idaho Power, the air conditioner cycling programs of PacifiCorp and Milton-Freewater, and the Portland General Electric program that maintains the backup generation of some customers in exchange for the right to dispatch that generation into the power system under some circumstances.

Some utilities also have "demand buy-back" programs, which notify customers of prices the utility offers for reductions in electricity use for specified periods; the customers can then reduce their use and be compensated based on the offered price and the amount of reduction. These buy-back programs have not been exercised very often since 2001, and the utilities report that there has been little customer response to offers based on relatively low spot prices for energy.

Meters

Many demand response programs require meters that can measure the customer's energy use hourly (in contrast to the monthly total measured by traditional meters), so that the customer's use (and reductions in use) at specific times can be credited. Many large industrial customers already have such meters, but except for Puget Sound Energy, most utilities' residential and smaller commercial customers do not. The cost of advanced meters continues to decline and their capabilities and usefulness to utilities continue to increase, and we expect advanced meters to be adopted more widely in the next few years. Portland General Electric has proposed to install advanced meters for all customers, and Idaho Power is monitoring the performance of advanced meters installed for about 5 per cent of their customers, in preparation for responding to the Idaho Public Utility Commission's direction to move to advanced meters for all their customers.

Progress toward 500 MW Target

Utilities have acquired demand response capability, but have had limited opportunity to test that capability. We had an unplanned test of that capability on July 24, 2006 when a combination of very hot weather both in the Pacific Northwest and in the rest of the West stressed the entire Western interconnection, particularly the West Coast. The best evidence is that utilities in the Pacific Northwest obtained somewhere in the range of 150-250 MW of demand response on that occasion. This experience must be interpreted in light of several caveats:

1. It was a summer peak problem, while most of our concerns up to now have been for winter peaks. As a result, the experience is of limited value in helping us estimate how much demand response we can depend on for winter peak problem. However, the July 24th experience also highlights the possibility, which has been suggested by some of our power system simulations, that summer peak problems are more of a risk than we have appreciated.
2. Some of the demand response realized by Pacific Northwest utilities was actually exercised outside the region (in the Utah part of PacifiCorp's service territory). As such, it perhaps should not be counted toward our region's accomplishments, though in the absence of the Utah reductions our region's problem would have been worse.
3. Some of the particular circumstances (e.g. errors in the weather forecast over a weekend, leaving operators with little time to deal with a shortage of resources on Monday morning) were unusual, although unusual circumstances can be expected to recur, and our goal is to have a reliable power system even when they do.

In summary, it's reasonable to interpret the experience of July 24th as evidence that we can get a useful amount of demand response when we need it, but not evidence that we have 500 MW that we can count on. We still need more work and experience.

Development of a Supply Curve

Compared to energy efficiency, the analytical work on demand response is still at an early stage. One of the most important contrasts between the two resources is that we have not yet been able to construct a comprehensive "supply curve" of demand response. This is partly because it has been a relatively short time since we began examination of demand response, partly because the analysis of demand response has unique difficulties[1] and partly because the general perception is that the region is not currently short of peaking capacity. Utilities have identified demand response opportunities, but have not yet done the sort of sector-by-sector, end-use-by-end-use analysis that was necessary to develop the conservation supply curves we now rely on for planning. Puget Sound Energy is considering several pilot programs for demand response that could help fill in some of the gaps.

To an extent, demand response is caught in something like a "Catch 22" situation:

1. Demand response offers the greatest savings if it can prevent or defer investment in new generating (and in some cases transmission and/or distribution) capacity. However, much of demand response is not regarded as a "firm" resource and not regarded as a credible planning alternative to investment in new generating capacity.
2. More experience with demand response would increase confidence in the reliability or "firmness" of demand response, but that experience is difficult to get if incentives are limited to levels based on the current spot market for energy.
3. If the power market were left to itself we could eventually expect enough volatility in spot prices to get more experience with demand response, but we may be embarking on

[1] The case can be made that while the analysis of energy efficiency is mostly straightforward engineering analysis based on well-understood principles of physics, analysis of demand response is more heavily based on consumer behavior (e.g. under what circumstances will energy users modify their use of energy), which is less well-understood.

policies (e.g. elevated reserve margins) that will prevent the west coast spot market from showing that kind of volatility.

4. In principle, demand response could help meet such policies' goals (e.g. elevating reserve margins) but it can only be counted toward reserve margins if it is regarded as a firm resource (return to point 1).

The problem is to gain the experience that makes demand response a credible resource, during a period when market conditions often make exercising demand response "non-cost-effective."

Better Estimation of the Value of Demand Response

Demand response is most useful as an alternative to peaking capacity. One obstacle to more rapid development of demand response is the common perception that our power system has more than adequate peaking capacity, due to the characteristics of our large hydroelectric system and recent additions of other generating capacity in our region. Historically, this was an accurate perception; our hydro system did provide plentiful peaking capacity compared to our energy requirements.

However, the situation is changing:

- In the short term, the peaking capacity available from the hydro system has declined because of operating restrictions designed to improve fish survival, and more restrictions could reduce available peaking capacity further. Increasing amounts of peaking capacity are also being used to integrate new wind generation.
- In the long term, the hydro system is now pretty much fully developed. Our options for additional generation to accommodate load growth are much the same as everywhere else in the nation. We are moving from a mostly-hydroelectric power system toward a mostly-non-hydroelectric power system -- from a system where energy capability is the primary planning concern toward a system where peaking capacity is the first concern.

In both the long and short term we are moving toward a situation where peaking capacity is scarcer and more expensive and where demand response is therefore more valuable.

The question is, where are we in that transition process and how valuable is demand response now and in the near future? To answer that question requires better modeling of the use of the hydro system to provide peaking capacity than we have been able to do in the past. Council staff is refining the Genesys model to address this question. In the first half of 2007 we should be able to make better estimates of the costs avoided by demand response (i.e. the value of demand response) during this transition period.

Regional Effort to Stimulate Demand Response

Council staff, with representatives of Bonneville, the 4 states' utility commissions, the Regulatory Assistance Project, and others has been exploring the possibility of a cooperative effort to stimulate the development of demand response in the region. The starting point for these discussions is the experience of two previous efforts in New England and the Mid-Atlantic states, the New England Demand Response Initiative (NEDRI) and Mid-Atlantic Distributed Resources Initiative (MADRI), respectively. The role of utility commissions was central to these initiatives, but the role of utility commissions in a "Pacific Northwest Demand Response

Project" and the identification of other elements of the NEDRI and MADRI processes that should be included are still under discussion.

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Utility Integrated Resource Plans

Participation in utility Integrated Resource Planning (IRP) processes is a key strategy for encouraging regional achievement of the plan and for tracking progress in its implementation. (See action items GEN 1- 6, ADQ-3, and CNSV-8). Council staff have been assigned to individual utilities and followed each utility's IRP activity. (See Figure K-1, below.)

IRP processes became popular in the late 1970s as a means for dealing with escalating oil and gas prices, inflation, and the capital costs associated with coal and nuclear power plants. The economic and environmental advantages of energy efficiency became widely recognized and conservation and cogeneration gained popularity. Regulatory agencies began to require utilities to more fully consider demand-side alternatives for meeting load.

Utility IRPs provide the Council with insight into each utility's plans for meeting its long-term requirements for energy. Utilities are the primary source of new supply-side capacity and a substantial source of demand-side resources in the region. Studying these plans, therefore, reveals the extent to which the region is tracking or departing from the Council's Fifth Plan. Excursions from the Plan can alert the Council to assumptions and constraints it may have overlooked. It can also raise questions about opportunities and risks the utilities may have failed to consider.

Utility	Lead	Last IRP	Current Activity
Investor-Owned			
Avista	Morlan	October 2005	Postponed to September 2007
Puget Sound Energy	Eckman	2005	Draft by Winter 2006, final by May, 2007
Portland General Electric	Schilmoeller	2002 IRP, Action Plan Update March 2004	Postponed to Second quarter, 2007
PacifiCorp	Corum	2004 IRP filed in January 2005, updated in November 2005	Postponed to January 2007
Idaho Power Company	Lindstrom	July 2004	Completed October 2006
Northwestern	Bushnell	Filed December 2005	Next IRP December 2007.
Consumer-Owned			
Seattle	Eckman	September 2000, updated October 2002	Draft to City Council by end of December, 2006
Tacoma	Grist	July 2004	Deferred to some time in 2007
PNGC	Fazio	May 2006	no information
Snohomish PUD	Grist	2004	Deferred to May 2007
EWEB	Grist	December 2004	December 2006 review deferred. Plans for 2007 IRP

Figure K-1: Status of IRPs

Six of the eleven utilities we have been tracking, Avista, PacifiCorp, Puget Sound Energy, Idaho Power Company, Northwestern Energy, and PNGC have completed an IRP review since the adoption of the Council's Fifth Power Plan in December 2004. PNGC, however, has not made its IRP publicly available. In July 2006, it appeared that many of the utilities were in the midst of updating their IRPs and targeted draft results or completed studies by the end of the year. These included Avista, Puget Sound Energy, Idaho Power Company, PacifiCorp, and Portland General Electric. Of these, only Idaho Power Company has completed their work. Consequently, of those utilities that are sharing their results, only two, Idaho Power Company and Northwestern Energy, have IRPs that have been released since the plan and reflect current thinking. Based on the status of these reports, it appears another update in July 2007 is warranted.

Nevertheless, there appear to be some generalities to draw from conversations and IRP meetings. The near term focus on conservation and wind or other renewables in the Council's plan is shared by most utilities. It appears that the region is on track to secure the Council's target for conservation, with some utilities meeting half of their load growth with conservation. Many utilities foresee additional generating resource needs before the Council's Power Plan does. There is more construction overall than called for in the Fifth Plan. Natural gas and coal remain prominent resource candidates for some utilities, despite recognized risks. Two utilities are beginning to look at advanced nuclear designs after 2020. Most utilities are reluctant to commit to IGCC plants at this time although the technology is being considered as a possibility in the future. Many utilities reference Council work for data on power resource cost and performance, load- and natural gas-price forecasts, conservation potential estimates, reliability and adequacy standards, and risk management and measurement concepts.

What follows is an assessment of utility plans, based on IRPs and recent conversations with the utilities.

Avista – Avista is currently in the process of developing its 2007 IRP. It plans to submit its IRP to the public utility commissions in September 2007. Avista currently has a peak load of about 1700 MW and energy load of 1050 MWa. Its energy resources are about 33 percent hydro, 32 percent natural gas- and oil-fired, 19 percent purchases, and 14 percent coal-fired, with a small remaining portion of biomass generation.

Avista developed a preliminary portfolio of optimized resources for discussion purposes within the Technical Advisory Committee, comprised of an added 986 MW capacity by 2027:

- Wind 20%, acquired early in planning period
- CCCT 12.6%, also acquired early in planning period
- Coal 6.7%, assumed to be IGCC, no pulverized allowed
- Other renewables, 16.2%, acquired throughout
- Oil sands 32.7%, between 2015 and 2024
- Nuclear 11.6%, after 2025

Demand-side resources, however, haven't been evaluated yet.

Differences of this draft portfolio from their 2005 IRP are
- Renewables are lower, although non-wind renewables are higher.
- Gas is higher but has a small role in total
- Coal is much less
- Oil sands were not considered in 2005 IRP
- Nuclear appears only after 2025, and it was not considered in 2005 IRP.

Idaho Power Company (IPC) – The Idaho Power Company filed their 2006 IRP with the Idaho and Oregon Public Utilities Commissions September 2006. Between 2006 and 2025, the planning horizon for the IRP, IPC expects to add 80 MW (2.1%) demand and 40MWa (1.9%) energy annually to the existing requirements base (2961 MW and 1660 MWa, respectively). It currently meets the energy requirement with 36 percent hydro generation, 32 percent coal-fired production, 22 percent net purchases, and 10 percent gas-fired generation. This utility encounters import difficulties during periods of peak summer requirements, especially when Pacific Northwest hydrogeneration is above average, because of transmission congestion from PNW deliveries to the southeast.

The selected portfolio in the IRP adds supply side resources capable of providing 1,089 MW of energy, 1,250 MW of capacity to meet peak-hour loads, and 285 MW of additional transmission capacity from the Pacific Northwest. The portfolio also includes DSM programs estimated to reduce 2025 energy loads by 88 MWa and peak loads by 187 MW, acquiring on average about 4.9 MWa and 9.35 MW annually. The timeline for adding resources is:

- 2006 - develop implementation plans for new DSM programs with guidance from the EEAG; investigate opportunities to increase participation in the highly successful Irrigation Peak Rewards DSM program; evaluate the Energy Efficiency Rider level to fund DSM expansion
- 2007 - finalize DSM implementation plans and budgets with guidance from the EEAG; evaluate/initiate DSM programs
- 2008 - 100 MW wind; evaluate/initiate DSM programs
- 2009 - 50 MW geothermal
- 2010 - 50 MW CHP
- 2012 - 150 MW wind; 225 MW transmission McNary-Boise
- 2013 - 250 MW Wyoming pulverized coal
- 2017- 250 MW Regional IGCC coal
- 2019 - 60 MW transmission Lolo-IPC
- 2020 - 100 MW CHP
- 2021 - 50 MW geothermal
- 2022 - 50 MW geothermal
- 2023 - 250 MW INL nuclear

The next IRP will be in 2008.

Northwestern Energy (NWE) – Northwestern released their Electric Default Supply Resource Procurement Plan in December 2005. While there has been progress on some of the contract acquisitions targeted in that plan, the strategic direction remains unchanged. The next plan is slated for December 2007. NWE expects to start work on the next resource plan update starting in January 2007.

The most obvious and pressing uncertainty facing NWE is the resource requirement created in mid-2007 by the expiration of two primary PPL Montana (PPL) contracts. These two contracts currently provide about 55 percent of the total energy needs of the default supply. NWE continues it efforts to find contracts to bridge requirements to longer-term purchase-power agreements (PPAs). They now have approximately 85% of our physical default supply load requirement obligation under contract for CY2007. This includes purchases from PPL.

NWE has developed portfolios that contain PPAs for specific resource types, such as coal-fired generation or wind power. NWE estimates that its current resource energy base is about 36% coal, 36% hydro, 9% wind, and the rest (18%) natural gas-fired. The four favored portfolios for resource expansion all assume a bridge contract between the expiration of the PPL contracts and December 2011. By 2010, NWE estimates its annual energy requirement will be about 750 average megawatts. Future resource additions are as follows:

	Portfolio 2	**Portfolio 14**	**Portfolio 18**	**Portfolio 31**
2010		100 MW wind, 264 MW gas-fired CCCT	200 MW wind, 264 MW gas-fired CCCT	200 MW wind, 100 MW gas-fired SCCT
2013	600 MW coal	200 MW coal	200 MW coal	400 MW coal

where, as usual, SCCT denote single-cycle combustion turbines and CCCT denotes combined cycle combustion turbines. It should be noted that these values are in MW, and wind and SCCT will typically operate at lower capacity factors than coal plant or CCCTs. This means that while Portfolio 2 results in near energy balance for NWE, the others leave NWE in an energy deficit situation. Moreover, NWE needs several years of operating experience from the Judith Gap project before committing to any additional wind energy purchases. Finally, only about one-third of NWE service area that falls within the Region, so the preceding figures should be discounted accordingly for a Council perspective.

NWE expects to ramp up their conservation activities aggressively over the next several years. By 2007, they expect to acquire 5 MWa of conservation annually. (Again, about a third of this figure accrues to the Region.) They believe they can sustain that level over the next 20 years. This would effectively cut their load growth in half.

Puget Sound Energy (PSE) – PSE completed its last IRP in 2005. That IRP concluded that PSE has a significant near term need for resources. To that end, PSE accelerated its conservation programs and issued a request for proposals (RFP) in fall 2005 seeking up to 1,500 average-megawatts of new power-supply resources. PSE's requirements are roughly 4730 MW peak and

2470 MWa energy, which they meet from 34 percent hydro, 29 percent coal, 20 percent cogeneration, 11 percent gas-fired turbines, and 5 percent miscellaneous sources.

Out of 120-plus submitted bids PSE short-listed seven proposals. In early November PSE announced that it had entered into an agreement to purchase the 277-megawatt (MW) combined cycle gas turbine (CCGT) at the Goldendale Energy Center operating in south-central Washington from Calpine for $100 million. PSE has also recently brought on line 150 MW of wind and is in the process of acquiring additional renewable resources (mostly wind) so that these resources can serve at least 10% of its load (about 5160 MW, 2790 MWa) by 2013. PSE has also acquired approximately 20 MWa of energy savings annually since 2004.

PSE's next IRP is scheduled to be completed in the spring of 2007. In this IRP, PSE will be testing alternative resource portfolios across seven "scenarios." Preliminary results indicate that the projected cost of all supply-side resources has significantly increased since 2005. This was confirmed when PSE reviewed the bids it received in its 2006 all resource RFP. The "low end" of the 2006 bids were $15 to $20/MWh higher than comparable resource bids in 2005.

Portland General Electric (PGE) – PGE plans to conclude the public involvement process on December 8 and file their IRP by second quarter, 2007. Its 2002 IRP was last updated in March 2004.

PGE currently has locked-in short-term purchases to cover a 500MWa resource shortfall from its 2300 MWa load. The Port Westward combined-cycle combustion turbine and Biglow Canyon wind project are slated to come on-line in 2007 and 2008, respectively. In 2008, PGE will be roughly in energy balance on a critical hydro basis. (Critical hydro generation for PGE is about 125 MWa lower than normal in 2007.) Power from long-term contracts will diminish slowly, and by 2012, PGE will again face a 440 MWa shortfall. This shortfall will grow with load requirements. On a capacity basis, PGE is short over this time period, achieving minimum shortfall of about 500MW after the completion of Port Westward. PGE's current energy resources are 35 percent net purchases, 28 percent natural gas-fired turbines, 26 percent coal-fired generation, and 10 percent hydrogeneration.

PGE is in the process of examining ways of filling the shortfall, primarily from 2012 on. Candidate portfolios include reliance on the short-term market ("do nothing"), maximizing energy efficiency and renewables, another CCCT, another conventional coal-fired unit, and an IGCC unit.

PGE relies on the Energy Trust of Oregon for its energy efficiency acquisitions. The Trust has identified 13 MWa as a reasonable annual acquisition goal.

Seattle City Light (SCL) – SCL will be presenting its draft IRP to the Seattle City Council by the end of December. The City Council is scheduled to adopt a final IRP early next year.

SCL's energy generation mix is currently about 45 percent owned hydrogeneration and 45 percent BPA and other contract hydrogeneration. The rest is made up from biomass generation, nuclear energy, wind, and non-hydro contracts. SCL serves a load of 1820 MW peak and 1140 MWa energy.

SCL's draft analysis indicates that it has sufficient resources to meet its forecast loads through 2010 with the addition of a small landfill gas project in 2010 and call options for winter energy during 2009. It also concluded that it should maintain and, if possible, accelerate its conservation acquisitions. In accordance with city policy, all portfolio's examined were "carbon neutral." Therefore, in SCL's IRP the cost of offsetting carbon emissions improved the economic competitiveness of renewable resources. As a result SCL's draft portfolios rely primarily on renewable resources, including wind, geothermal and landfill gas. None of the portfolios considered contain coal or nuclear. While results are preliminary, SCL will probably acquire between 6 and 12 MWa of energy efficiency annually.

PacifiCorp – PacifiCorp is scheduled to release a draft of the 2006 Integrated Resource Plan in January 2007. There is one more meeting of stakeholders to discuss the IRP analysis in December 2006.

PacifiCorp system loads in 2005 were about 8900 MW summer peak, 8300 MW winter peak, and 5450 MWa energy, of which Oregon, Washington, and Idaho comprise about 2240 MWa. (These estimates do not include Clark County PUD load, which will be leaving the PacifiCorp system.) By 2017, system energy loads will grow to about 7300 MWa, or about 2600 MWa for the tri-state area. Energy to meet current requirements is about 83 percent coal, 8 percent hydro, 7 percent cogeneration, and small amounts of natural gas- and oil-fired, biomass, wind generation.

At this stage of the IRP process, the goals for conservation are a firm 220 to 240 MWa of system-wide savings with a possibility for another 200 MWa over the next 10 years. The likely goal for demand response is about 200 MW over the same period.

As of their October 31 public process meeting, PacifiCorp was considering nine candidate portfolios. All candidates in at least 1,000 MW of renewables, to bring the system total to 1,400 MW, with some candidates holding an additional 600 MW. All candidate portfolios have 1,000 MW of load control or demand-side management and distributed generation added. All but one candidate included a 340 MW coal plant in 2012, followed by another 600 MW or 750 MW in the 2013 to 2017 timeframe. All plans incorporated two IGCC plants on the west side of the Cascades in the 2016 to 2018 period. The first is 200MW; the second is 300MW. All but one candidate anticipate a 300+ MW single-cycle combustion turbine (SCCT) coming into service in 2012. Five include about 600 MW of combined cycle combustion turbine, also added in 2012. PacifiCorp is also evaluating a 12 percent planning reserve margin in three candidates, in lieu of the standard 15 percent margin. Finally, five of the candidates employ over 1,000 MW of purchases ("front office transactions") over the 2012 to 2016 period.

Earlier this year PacifiCorp released an initial draft RFP for four "benchmark" coal resources with capacity totaling between 1600 and 2290 MW in the 2012-14 period. That RFP has since been changed to two resources totaling between 840 and 915 MW in the 2012-13 period.

Eugene Water and Electric Board (EWEB) – The most recent IRP was completed in 2004. The following is based on that IRP, but it should represent current thinking. A review of that IRP was scheduled for December 2006, but will not be prepared. IRP plans for 2007 are still under formulation.

Total loads were about 310 MWa in 2004 and the utility counts about 350 MWa of resources and contracts under critical water conditions. EWEB's generating resources are predominantly hydro electric (71 percent) through BPA purchases and from several facilities on the middle sections of the Willamette River and tributaries. Cogeneration and wind make up most of the remainder. BPA supplies about 72 percent of EWEB's power needs. Current practice is to stay long.

The 2004 IRP identified the following key issues for EWEB:

- Bonneville price increases combined with below average hydroelectric conditions in four of the five years prior to 2004 have had a serious impact on EWEB's financial condition. Rates are up and reserves are low
- Re-licensing of EWEB's Carmen-Smith hydro facility is a potential large cost and important decision facing the utility
- Climate change impacts on owned hydro production are a concern (west-side of Cascades)

The 2004 action plan calls for continued high rates of conservation acquisition (5 percent of gross revenues) generally aimed at a gradual displacement of a small portion of BPA and other contract purchases and limited development of prioritized 'lost-opportunity' generation as financial conditions permit. Priority of new resources is given to conservation, wind, hydro, solar thermal, biomass, fuel switching, distributed generation, and cogeneration in that order. The action plan gives rough guidance on how much of each new resource and favors mostly conservation and wind. The plan recommends a focus on 'lost-opportunity' renewables or contracts, limited to 5 to 20 MWa in the near term.

Snohomish County PUD (Snohomish) – Snohomish has not yet updated its 2004 IRP. A 2006 update was planned but has been delayed. The plan is to develop one by May 2007. Snohomish is gearing up to do more IRP analysis internally.

Total loads for Snohomish are about 850 MWa energy, about 1400 MW peak. The PUD buys about 85 percent of its power from BPA. About half is BPA's block product and the other half is slice. Owned resources include Jackson hydro (99 MW), cogeneration at a Kimbery Clark plant (50 MW), and Klickitat and some diary landfill gas (7 MW). Snohomish is experiencing significant load growth, due to migration from Seattle, and expects it will need new generation is in the 2009 time frame. Load growth is 15-20 MWa per year after conservation, 9000 new connects per year. Snohomish sees no slow down in load growth.

This increase in loads creates an opportunity to meet more of their requirements with conservation than would be case if their loads were flat. Most thermal resources appear to be more of a mismatch, either in terms of planning and construction lead-time, size, cost, or risk.

Tacoma Public Utilities (Tacoma) — Tacoma has not updated its 2004 IRP. The following is based on that IRP and may not be current. The next installment of IRP is scheduled for sometime 2007.

Tacoma's loads are about 570 MWa. BPA net requirements supply about 400 MWa of resources. The utility owns four hydro projects, buys hydrogeneration from Grant's Priest Rapids project, Grand Coulee irrigation, and BPA's Environmentally Preferred Product. The utility is surplus. No new resources were planed in the 2004 IRP. Under most water conditions Tacoma is a net seller of power.

Like most partial requirements utilities, the form and structure of BPA purchases is one of the biggest issues in play. Tacoma expects to lose some operational flexibility with re-negotiated Priest Rapids contract (automatic generation control or AGC, peaking, shaping, reserves and storage). Utility-owned hydrogeneration projects at Cushman and Cowlitz may decrease hydro flexibility. Cowlitz projects (462MW) re-license is up in the air and the project needs a major refurbish. The potential loss of flexibility is driving consideration of improved planning tools for operational decision making.

Conservation acquisitions remain relatively low in 2006 mostly to avoid upward pressure on rates. The utility is focusing on lost-opportunities, market transformation and low-income conservation. The IRP sets forth options for higher conservation targets under high load growth or high price futures.

The 2004 IRP action plan focuses on recommendations for the next IRP, including

- Continued involvement in the forums related to the future role of BPA in the region.
- Conducting further evaluation of aspects of operational flexibility in Tacoma Power's current power supply portfolio and how it will change in the future.
- Continued enhancement of analytical and decision support system tools for optimization of the power supply portfolio, and
- Initiation of a new, comprehensive conservation potential assessment (CPA).

Clark Public Utilities (Clark) – No IRP at this time

Pacific Northwest Generating Utilities (PNGC) – No information

Resource Adequacy Standards

During the 1990s, the entire West coast saw little development of new electricity generating resources. This may have been prompted, in part, by the promise of deregulation and concerns regarding getting returns on new capital investments. The Northwest's resources and loads were about in balance in 1990 but declined steadily though the decade. By 1999, the load/resource balance was nearly 4,000 average megawatts (MWa) deficit. There was concern about the adequacy of the region's power supply. In 2000, the Council concluded that three years out (by 2003) the region would face about a one-in-four chance of service curtailment, however, no significant actions were taken to alleviate the problem.

Then, in 2001, with a dysfunctional California electricity market in place, the Northwest experienced its second driest year on record. Electricity prices soared and actions were taken to avoid uncontrolled curtailment in the region. While a crisis was averted, it came with a cost. The Bonneville Power Administration paid its direct service industry customers to halt operations. It also curtailed almost all bypass fish spill (used to improve migration survival). Many Northwest utilities purchased or leased high-operating-cost generators to augment the lack of hydroelectric generation. Overall, the region got by without a major curtailment but the effects of that crisis continue to haunt us today, in the form of higher electricity prices.

Understanding that resource adequacy was a key concern for the region, the Council incorporated two action items into its Fifth Power Plan to specifically address this issue. Action items ADQ-1 and ADQ-2 (provided below) call for the establishment of reporting standards and the creation of an advisory committee to aid the Council in developing adequacy standards for the Northwest.

ACTION ADQ-1
Establish regional and West-wide reporting standards for the assessment of adequacy.

It is essential to have accurate, consistent, and transparent information in order to judge the adequacy of the power supply. The Council will continue to work with the Northwest Power Pool, the Western Electricity Coordinating Council (WECC), and the Committee on Regional Electric Power Cooperation to establish the necessary measures of resource adequacy and reporting standards.

ACTION ADQ-2
Carry out a process to establish adequacy standards.

The Council will establish a Northwest Resource Adequacy Forum. This forum will examine alternative adequacy metrics and standards for the Northwest and their compatibility with West-wide standards being developed by the WECC and others. The forum should consist of utility policy-makers, regulatory commission representatives, and other relevant parties who will help to develop standards and support their implementation. A technical subgroup of this forum will have the function of providing policy-makers viable options for both metrics and standards for the Northwest. The objective would be to reach agreement on appropriate adequacy metrics and *standards by the end of 2005. In addition, the Council will continue to work through the WECC and other forums toward West-wide adequacy metrics and standards.*

In response to these two action items the Council, in conjunction with BPA, established the Resource Adequacy Forum. The Forum's two committees, a policy steering committee and a technical committee, have met approximately every month since early in 2005. The Forum recognized early on that an adequacy standard for the Northwest would have to be made up of two components – one to deal with energy (or fuel) related issues and one to deal with capacity (or machine) related issues.

In May of 2006, the Council adopted the Forum's proposed standard for the energy component. That standard uses the balance between resources and load, as a measure of the power supply's adequacy. The energy target is set to zero, which means that for the power supply to be adequate, on an energy basis, the average energy capability of the system over the course of a year must be at least as much as the average load. This almost seems too obvious, but the Forum's proposal includes the addition of a 1,500 MWa planning adjustment to the resource side of the equation. The magnitude of the planning adjustment is derived from a probabilistic analysis that estimates the risk of service curtailment often referred to as a loss-of-load probability. The planning adjustment, in simple terms, is a measure of how much the region is willing to depend on non-firm resources, such as out-of-region market generation and hydroelectric system flexibility (the ability of the hydro system to draft below normal elevations for a short time during emergency conditions). Currently the region's annual load resource balance is about 3,900 MWa (including the 1,500 MWa planning adjustment).

In December of 2006, the Council adopted a pilot capacity standard. The capacity standard, like the energy standard, uses the balance between resources and loads as a measure of adequacy. The difference is that the capacity standard measures the adequacy over the peak demand hours of the day. The measure used for the capacity standard is a reserve margin, which is simply the amount of surplus generating capability over the peak hourly loads, in terms of percent. The capacity target is made up of components that cover various types of contingencies. Operating reserve requirements make up 6 percent of the target. The reserve to cover adverse temperature (enough for a 1-in-20 year event) is currently set to 15 percent for winter and 6 percent for summer. And, in a similar fashion to the energy standard, a planning adjustment reserve is added to the target to cover other contingencies. The magnitude of the planning adjustment reserve is derived from a loss-of-load probability analysis. That component is currently 4 percent for winter and 7 percent for summer. Thus the pilot winter capacity target is 25 percent and the summer target is 19 percent.

Currently the Northwest's power supply has a winter reserve margin of 41 percent and a summer margin of 28 percent, both well above the proposed targets. The capacity standard is interim in nature, meaning that over the course of this next year, more analysis and research are planned to validate the data and to calibrate the analytical tools. It is quite likely that the winter and summer targets will be revised. In fact, the Council plans to review, on a yearly basis, not only the adequacy of the power supply but also the appropriateness of the energy and capacity targets.

Council staff has been and continues to be active in the WECC Load and Resources Subcommittee (LRS), which is the WECC entity charged with overseeing the various adequacy assessments and with developing adequacy metrics and targets. The current schedule for developing metrics and targets involves working through the established WECC approval process leading to a Board decision in the summer of 2007. The LRS continues to work to improve the various adequacy assessments done by WECC. Having Council and other Northwest staff on the LRS is important to ensure that WECC and Northwest approaches to resource adequacy are compatible and to minimize, or at least be able to explain, discrepancies in the assessments.

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Bonneville Role

Since the Comprehensive Review of the Northwest Energy System in 1996, the region has understood that a new approach to Bonneville's role in the Pacific Northwest region's electrical system is needed. The region has also understood the general nature of the change that is needed. The Council has supported these changes consistently in its comments to Bonneville and the region's utilities during their various attempts to implement these changes. In spite of agreement about the basic nature of the changes that are needed, the region has not succeeded in making the changes.

The Council's Fifth Power Plan included a chapter on The Future Role of Bonneville and several action items directed at the needed changes. The changes include:

- Bonneville selling the existing Federal Base Resources to public utilities at cost based on an allocation to existing utilities. If a utility requires additional power beyond its allocation it would pay the incremental cost of that power, whether purchased from Bonneville or some other source.
- Bonneville settling the residential exchange for investor-owned utilities, and for consumer-owned utilities.
- Bonneville continuing to fulfill its stewardship responsibilities to acquire cost-effective conservation, encourage the development of renewable resources, and mitigate for fish and wildlife impacts of the hydroelectric system.
- Embodying these changes in new long-term (20-year) contracts.

Bonneville issued a Long-Term Regional Dialogue Policy Proposal in August 2006 following intensive regional discussions over the preceding couple of years. Bonneville received extensive comments from many parties including the Council. January 2007 is set as the date for a Bonneville record of decision on the Regional Dialogue policy. Based on a hearing with Bonneville and Department of Energy officials on December 6, 2006, there are still some major contested issues. These include the residential exchange settlement, service to aluminum companies, and cost controls and dispute resolution procedures. The process of crafting contracts to implement the regional dialogue changes is extremely difficult, but the process is ongoing.

The Bonneville policy proposal is consistent with many of the Council's more specific Regional Dialogue goals as stated in the Council's Fifth Power Plan (Plan). These goals include the following:

- Preserve and enhance the benefits of the Federal Columbia River Power System (FCRPS) for the Northwest
- Not increase and, preferably, reduce the risk to the U.S. Treasury and taxpayers
- Achieve an equitable sharing of the benefits of the federal power system
- Develop and maintain widespread support for the federal system and reduce conflicts within the region
- Align the costs and benefits of access to federal power

- Maintain and improve the adequacy and reliability of the Northwest power system
- Make clear who will be responsible for meeting load growth and on what terms
- Provide clear signals regarding the value of new energy resources
- Lessen Bonneville's exposure to market risk
- Lessen Bonneville's impact on the market
- Satisfy Bonneville's responsibilities for conservation and renewable resource development
- Satisfy Bonneville's responsibilities with respect to fish and wildlife; and
- Accomplish all these goals efficiently and at as low as possible a cost to the region's consumers

We will not know how successful the implementation of these important changes will be for several months. However, the progress is encouraging, and the commitment of time and energy to the process is impressive. Many think that the regional dialogue would be the largest change in the regional power system since the Northwest Power Act of 1980.

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Transmission Issues

Introduction

The Fifth Power Plan was the first one to address transmission actions explicitly. This was a major step that recognized the importance of the transmission system, both regional and westwide, in facilitating or hindering regional and western power markets. The Power Plan highlighted the increased stresses on the transmission system, as well as the opportunities, created by the restructuring of the electric power system in recent years.

The Plan identified several kinds of problems facing the regional transmission system, including:

- 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;
- Inability to effectively monitor the wholesale electricity market, identify market power abuse, or provide mitigation and accountability;
- Difficulty in reconciling actual physical available transmission capacity with that available on a contractual basis, resulting in inefficient utilization of existing transmission and generation capacity;
- 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.

In response to these problems the Plan described several actions. Recognizing that transmission planning and operations are connected importantly to the larger region and to the rest of the western interconnection, the Plan called for actions in both Northwest and larger western arenas. The following sections list the Plan’s action items and describe how they have been carried out and what other changes in the transmission system environment have helped to address the problems they were aimed at. The paper will conclude with a reiteration of the list of problems and a summary of the actions that are currently being taken (or not taken) to address them.

The actions are described out of numerical sequence to assist in the presentation.

Action TX-2

Bonneville and other transmission providers should work to improve the 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 Open Access Same-Time Information System (OASIS) site provides a broader mechanism for facilitating a secondary market in transmission capacity than single-provider OASIS sites. WesTTrans could begin to address the discrepancy between physical capacity and contract path limitations by developing a common available transmission capacity calculation. Bonneville and other Northwest transmission owners should participate in this initiative.

This action item is addressed as part of the discussion of the following item.

Action TX-3

It should be a high priority for regional interests 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. However, the Council is concerned that the time to address these issues is growing short. The RRG/Grid West process has important decision milestones during the next year. If it appears unlikely that the Grid West process will reach a successful conclusion by the end of 2005, the Council will work with the region to find alternatives to resolve these regional transmission issues.

ColumbiaGrid

Since the publication of the Fifth Power Plan, the Grid West effort has failed, fundamentally through an inability of the various regional parties to agree on the level of independence from direct control by regional interests and the degree of FERC oversight that would be acceptable. Since then, Bonneville and six other control area operators[1] have formed an entity called ColumbiaGrid, which is intended to be an umbrella organization under which a set of multiparty contracts will be put in place to address specific issues, including planning, reliability, congestion management, flow-based Available Transmission Capacity (ATC) calculation and a common OASIS. These contracts, called functional agreements, would be open to both ColumbiaGrid members (who would be expected to sign them) and to non-members who qualify by virtue of operating facilities relevant to the agreement (e.g., other control area operators, transmission owners and/or generation owners).

The planning and expansion functional agreement has been finished and is expected to be offered for signature in mid-January 2007. It contemplates a planning staff to coordinate and do multi-system reliability expansion studies for signatories, a biennial plan, and provisions for supporting the plan before FERC or other relevant regulatory agencies in order to aid in its implementation. The functional agreement also contains a commitment to work toward the creation of a common study queue for the signatories.

[1] Avista, Chelan County PUD, Grant County PUD, Puget Sound Energy, Seattle City Light, and Tacoma Power.

Under the current FERC pro-forma open access transmission tariff (OATT, which is widely implemented, even by non-FERC jurisdictional transmission providers like Bonneville), applicants for transmission service where there is no available transmission capacity are placed, in order of application, in a study queue for the provider to do the planning studies necessary to determine how to provide the requested service. If the service crosses two or more providers, the applicant will go into multiple queues, for which the study priority is fixed, though there is some attempt by the providers to coordinate studies for the same application, despite different places in different queues. A single, common study queue for multiple providers, such as is targeted by ColumbiaGrid, would be a major step forward in improving the efficiency of the planning process.

WesTTrans has been adopted as an OASIS platform by a number of Northwest utilities[2]. The two major transmission owners that do not participate at this time in WesTTrans are Bonneville and PacifiCorp. The ColumbiaGrid effort at a common OASIS for its members, and any other transmission providers that sign the agreement, proposes the vendor of the WesTTrans platform as one likely provider of the common OASIS services. The ColumbiaGrid work on a common Northwest OASIS contemplates longer-term actions including development of a common flow-based ATC methodology and of the interface for a common queue for transmission service and interconnection requests, which would feed into the ColumbiaGrid planning process, and would go beyond what WesTTrans currently provides.

Work on the reliability functional agreement is focused on a near-term real-time congestion management procedure that would assist Bonneville in the summer of 2007, and on taking over more of the operation of the procedure in subsequent years. Wider-scope reliability efforts, aiming to address problems before they show up in real time, will be focused on working with, and complementing as necessary, the larger reliability efforts of WECC. This decision was taken recognizing the magnitude of the effort being undertaken by WECC, both to increase the scope of the reliability coordinator responsibilities and actions and to provide significantly better monitoring and analytical tools, which are intended to be available to control area operators as well.

WECC

While the regional effort has become less ambitious than that contemplated by Grid West, a larger effort that will address many of the regional problems in the context of west-wide problems and solutions has emerged. Changing NERC requirements for reliability, prompted by the 2003 Northeast blackout and supported by the legal backstop given by the 2005 Energy Policy Act, drive this effort. This effort shows up in two parts, focused on the role of the reliability coordinator.[3]

[2] Only FERC-jurisdictional transmission providers are required to maintain an OASIS system. Currently Bonneville and BC Transmission Corp. (BCTC) are the only Northwest non-jurisdictional entities that provide an OASIS. (Generally, the other non-jurisdictional entities are not transmission providers in any case.)

[3] The NERC requirements are described in terms of a function called a Reliability Authority, but that role is borne by entities called “reliability coordinators” in WECC. The Pacific Northwest Security Coordinator, PNSC, is the reliability coordinator for the Northwest Power Pool region.

The first part is the WECC Reliability Coordinator Initiative. This is an initiative of the WECC Board to ensure that WECC will be able to meet the new NERC requirements for substantial additional pre-operating hour and within-operating hour ("real time") visibility over the state of the system in its footprint.

One of the major potential reliability problems for current operations of the transmission system is the lack of information on what is really going to happen in real time. Transmission schedules can be changed up to 20 minutes before real time, and in real time if allowed by the control area operator. The schedules themselves also often do not contain useful information about where the ultimate generator and load are located (though the load is largely easier to identify than the generation, in those instances without details). A generation source in a transmission schedule may be as large as a control area. The uncertainty about the physical flow impact of scheduled transactions is compounded by the effect of unscheduled flows[4]. This is important to know for the control area to set its net interchange, key to maintaining system frequency, but it is not enough detail to know whether any particular physical transmission path monitored by that control area will be overloaded or not in real time, and thus be a threat to system reliability.

The new NERC requirements will require the reliability centers to have more information about expected actual generation and load ahead of real time, as well as better tools to do forward and real time analysis of the state of the system.

The second part of the WECC effort is the development of the West-wide System Model (WSM), a computer model of the western interconnection that is intended to be updated with real time data, so that the reliability centers and control areas are able to see what is going on not just in their own footprint but in surrounding footprints as well. For the reliability centers, this gives each of them (there are currently three, though the current plan is to go to two) the ability to be a complete backup for the other(s).

Northern Tier Transmission Group

The Northern Tier Transmission Group (NTTG) is a newly formed organization, currently consisting of utilities on the east side of the Northwest Power Pool footprint.[5] It intends to undertake the regional planning effort called for in FERC's proposed revision[6] of the pro-forma OATT on behalf of its members. No specific details have been developed yet.

NTTG also expects to address ATC calculations for its members, though whether it will take on flow-based ATC has not been addressed yet. Finally, NTTG proposes to support an initiative to pool regulation services among the control area operations of some of its members, which will

[4] The physical flow impacts of transactions that are scheduled between a sub-set, or even within a single control area show up as unscheduled flows in adjacent, or even distant, control areas. This is a consequence of the physical characteristics of electric power transmission and the mismatch between commercial scheduling practices and physical electric power flows.
[5] NTTG consists of Northwestern Energy, Idaho Power, PacifiCorp, and two Utah public power entities, Utah Associated Municipal Power Systems (UAMPS) and Deseret Power (a generation and transmission cooperative).
[6] See Appendix O "Federal and State Energy Policy" for more details of the proposal.

both reduce the cost of providing regulation and help to support the integration of wind resources into their control areas.

Action TX-1

The Council will work with Bonneville, other transmission providers, permitting agencies, and project developers to plan for long-distance transmission needs to support the resource development called for in the power plan.

The Council will work with the Northwest Transmission Assessment Committee [NTAC] and similar organizations to improve the integration of resource and transmission planning. This effort will incorporate the transmission planning assessments into the Council's power plan. Transmission planning should specifically address the needs of wind and other location-bound resource development.

Council staff has participated, and continues to participate, in various NTAC activities, focusing particularly on the studies involving wind development in central Washington and Oregon and the transmission that would be necessary to integrate it and connect it to west-side load centers. The NTAC effort has consisted of a number of separate areas of study, including the wind study just mentioned, a study focusing on upgrades on the paths from Montana to Northwest load centers, upgrades on the path through the Puget Sound area and various proposals to connect resource areas in British Columbia and Alberta with the Northwest and California.

Several of these efforts have borne fruit. The Montana-Northwest study has resulted in a recently announced agreement by the partners in the Colstrip 500 kV transmission lines (Northwestern Energy, Puget Sound Energy, Portland General Electric and Avista) to identify and develop upgrades to those lines, as a first step in integration of additional generation from Montana with coastal load centers.

Two additional detailed project reviews have been announced in July and August for connections from Canada to the Northwest and Northern California. One, the Northern Lights project sponsored by TransCanada Ltd., will develop a proposal for a high-voltage DC (HVDC) line from the Alberta oil sands area around Fort McMurray to Celilo and the second, sponsored by Pacific Gas and Electric, will investigate several alternate connections, including an undersea HVDC cable, between British Columbia and Northern California, with intermediate substations in the Northwest.

The Western Electricity Coordinating Council (WECC), has begun a larger effort to coordinate and support interconnection-wide transmission planning, which will be based in part on direct WECC staff efforts and in part on supporting existing sub-regional planning efforts, like that of NTAC in the Northwest. This effort is under the direction of a Board-level committee, the Transmission Expansion Planning Policy Committee (TEPPC), and is being supported by WECC staff and a newly formed Technical Advisory Subcommittee (TAS) and associated work groups. This is a major initiative of the WECC Board, responding to various requests, including from the Western Governors' Association. TEPPC was formed this spring and the advisory committee is just in the process of getting going. Council staff is participating in several parts of the TAS.

Some of the major transmission operating issues (as opposed to the planning questions highlighted earlier) posed by the high levels of wind development being proposed for the region are being studied in the joint Council-Bonneville Wind Integration Action Plan initiative. This is a major effort to address wind integration issues comprehensively for the Northwest.

As noted above, both ColumbiaGrid and NTTG expect to take on significant planning roles. They will not necessarily overlap completely with the planning efforts of NTAC. ColumbiaGrid's effort will primarily be devoted to transmission upgrades needed for reliability or to meet contractual requirements. NTTG's role has not been spelled out it any detail yet. Both contain only subsets of the membership of NTAC.

Action TX-4

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.

Bonneville's Non-Wires Solutions Round Table continues to meet, with several pilot projects in progress. The pilot projects are providing information on what kinds of approaches are cost-effective, which additional questions need to be answered and where successes are likely to lie. BPA studies have focused on load areas on the Olympic Peninsula, in Southern Oregon and on the Southern Oregon coast. Other regional utilities, such as Puget Sound Energy, have also participated.

Other regional and west-wide planning efforts (such as NTAC's) have addressed the issue of non-wires solutions. It has most frequently been concluded that, because of the different skill sets and knowledge bases required for addressing demand (non-wires) solutions and transmission solutions (including such technically "non-wires" solutions as additional capacitors), it is often best that the actual analysis of the two alternatives be a joint effort of the entity responsible for the load service and that responsible for providing transmission, rather than putting the burden solely on the latter.

Summary

The problems listed in the plan are reiterated below, along with the key points about their current status made in the paper.

1. Difficulty in managing unscheduled electricity flows over transmission lines, leading to increased risks to electric system reliability:
    - Being addressed for ColumbiaGrid functional agreement signatories by actions to create real time and, in the future, pre-real time congestion management mechanisms
    - Being addressed for interconnection by WECC Reliability Coordinator Initiative steps, in response to strengthened NERC reliability standards

2. Lack of clear responsibility and incentives for planning and implementing transmission system expansion, resulting in inadequate transmission capacity:
   - Being addressed for ColumbiaGrid functional agreement signatories by creation of ColumbiaGrid planning process, though its role is focused on reliability and existing contractual transmission needs
   - Being proposed to be addressed by NTTG for its members
   - Being addressed for interconnection by WECC new transmission planning process and increased coordination and support for sub-regional (like NTAC) planning processes;

3. Inadequate consideration of non-construction alternatives to transmission:
   - Being addressed for Bonneville, and potentially for ColumbiaGrid, by Bonneville's Non-Wires Solutions Round Table
   - Problem is being highlighted in various planning processes, though implementation focused back to load-serving entities, for example, in their integrated resource plans

4. Inability to effectively monitor the wholesale electricity market, identify market power abuse, or provide mitigation and accountability:
   - Institutionalizing a regional market monitor being put on back burner by ColumbiaGrid, in part because it is not proposing to create new markets, and in part because, like Grid West, it is observing the progress of the market-monitoring studies being carried out by the states and FERC
   - FERC has created active market monitoring unit that is coordinating closely with the western states in following western markets as well as the western implications of national markets, for example, natural gas

5. Difficulty in reconciling actual physical available transmission capacity with that available on a contractual basis, resulting in inefficient utilization of existing transmission and generation capacity:
   - Being addressed in later phases of ColumbiaGrid for signatories of its functional agreement
   - Expected to be addressed by NTTG for its members

6. Transaction and rate pancaking, for example 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:
   - Addressing this issue was within the Grid West scope, but it is not being addressed by the other initiatives discussed above

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Federal and State Energy Policy

One of the key actions that can affect the implementation the Council's Plan is change to energy policy at both the state and national level. As part of the Biennial Assessment of the Plan, we have summarized some of the key legislative and policy changes that have taken place since the Plan was adopted. Sections of this assessment below address national changes and changes in each of the states in the Pacific Northwest.

National

Energy Policy Act of 2005

The electricity title, Title XII, of the Energy Policy Act of 2005 made a number of significant changes in the framework for the electric power industry in the U.S. Two changes are most relevant to the Council's planning efforts. The Act changed the way system reliability is overseen, and it created a federal backstop transmission siting authority in what has historically been a state arena. It also expanded the jurisdiction of Federal Energy Regulatory Commission (FERC) over third-party access to the transmission systems of otherwise unregulated transmission providers, such as Bonneville and publicly owned utilities. These changes will be described below.

None of these changes appears to require modifications to the Fifth Power Plan.

The Energy Policy Act of 2005 also includes a wide array of policy initiatives targeting improved energy efficiency and generating resources. These include activity in research and development, education, pilot programs, state program funding, and tax incentives, among others. Many of these depend upon actual funding being approved, but others are very likely to have some direct effect in the Pacific Northwest.

Mandatory Reliability Standards

The Act made reliability standards mandatory for all participants in the industry. It did this by allowing for the creation of an Electric Reliability Organization (ERO) and Regional Reliability Organizations (RROs, like WECC) that could create and implement mandatory reliability standards. These entities would be subject to FERC jurisdiction, as would all participants in the industry, as a backstop to ensure their implementation. This jurisdiction newly includes entities, like Bonneville or publicly owned utilities that are not FERC-jurisdictional for other purposes. NERC (now called the North American Electric Reliability Corporation) has applied for and been designated by FERC to be the ERO under the law. A delegation agreement establishing the relationship between NERC and WECC was approved by the WECC in December 2006.

This is significant because prior to this time industry standards, though widely observed, were ultimately voluntary, except for those entities that, in the West, had voluntarily signed the WECC Reliability Management System (RMS) Agreement. In addition to making the standards mandatory, the Act put an independent regulator, FERC, in charge of approving the standards. Failure to observe NERC standards, as well as the inadequacy of some of the standards, was widely observed to be one of the causes of the 2003 Northeast blackout.

There is one important exception, however, to the impact of the new regulatory regime. Neither the ERO nor FERC is authorized to order the construction of additional generation or transmission capacity or to set and enforce compliance with adequacy standards, an authority that is reserved to the states.

FERC Backstop Transmission Siting Authority

A second section of Title XII provides for a FERC backstop of state transmission line siting authority under the following conditions:

- When states do not have authority to site transmission facilities or to consider the interstate benefits of a project
- Where an applicant does not qualify for siting under state law, or
- Where the state siting body has withheld approval for more than a year or conditioned approval in such a way as to make the proposed project economically infeasible or unable to significantly reduce congestion

This authority applies only to proposed transmission lines that are within national interest electric transmission corridors, as previously designated by DOE. DOE has not yet designated any corridors.

The authority is further conditioned by a provision allowing the creation of interstate compacts by three or more contiguous states in order to do regional transmission siting. FERC can only exercise its backstop authority in a state subject to a siting compact if the states in the compact disagree about siting the proposed facility.

This new authority was largely opposed by the states, who currently are the sole siting authorities for electric transmission lines.[1] FERC has interpreted a state's "withholding approval" to include denial of a project, in its recently issued final order setting out the rules by which it will implement the authority.

Open Access for Non-Jurisdictional Utilities

The Act also gives FERC the authority to order otherwise non-jurisdictional transmission providers, like Bonneville or publicly owned utilities, to provide third-party access to their transmission systems on a comparable basis (rates, terms, and conditions) to that which they provide for themselves or affiliated marketers. It is not clear what the effect of this new authority will be, because, as noted below, most non-jurisdictional transmission providers already largely adhere to the same pro-forma OATT as jurisdictional utilities because of the reciprocity requirement that jurisdictional utilities only have to offer open-access service to those that provide it to them.

Energy Efficiency

The Energy Policy Act of 2005 includes a wide array of policy initiatives targeting improved energy efficiency and renewables. These include activity in research and development, education, pilot programs, state program funding, and tax incentives, among others. Many of

[1] FERC already had exclusive siting authority over interstate gas transmission pipelines.

these depend upon actual funding being approved, but others are very likely to have some direct effect in the Pacific Northwest.

For example, the EPACT 2005 established federal efficiency standards for 15 new products and requires the U.S. Department of Energy (USDOE) to adopt new or updated standards for nine additional products. Perhaps just as significantly, EPACT 2005 also requires USDOE to update over 20 of the existing federal standards and testing procedures that were long overdue for revision -- some by as much as 15 years. USDOE has committed to Congress that it will accomplish this task within the next five years.

Generating Resources

The EPAct 2005 extended the electricity production tax credit to projects in-service by the end of 2007 and expanded the scope of qualifying resources. The tax credit is currently the key driver of the rapid wind development underway in the Northwest. The "American Jobs Creation Act of 2004" had extended the credit to geothermal, open-loop biomass, solar energy, small irrigation power, landfill gas, municipal solid waste (MSW) combustion, and refined coal in addition to the formerly eligible wind, closed-loop biomass, and poultry-waste energy resources. The EPAct 2005 further expanded the credit to additions to existing hydropower facilities, new hydropower at non-power dams currently holding a FERC license, and Indian-owned coal, but removed the solar eligibility. Qualifying hydropower, landfill gas, and MSW receive $9/MWh, and other qualifying facilities $19/MWh, adjusted for inflation. The credit has not had an effect on other resources comparable to that on wind, largely because of the longer lead times typically required to develop and construct those resources.

A Clean Renewable Energy Bonds (CREBs) program was established as an incentive for projects developed by public entities and not able to take advantage of production tax credits. CREBs are interest-free bonds, yielding a tax credit rather than interest to purchasers. CREBs have been in high demand; this year only about 30 percent of requested bond amounts have been covered by IRS allocations.

The EPAct 2005 provides a variety of incentives for new nuclear plants, including loan guarantees, insurance against financial impacts of construction delays, and a production tax credit. The tax credit is limited to the first 6,000 MW of new capacity and will likely be fully subscribed before any commercial plants are proposed in the West. However, up to $1.25 billion is authorized through FY2015 to fund a prototype Next Generation Nuclear Plant to produce both electricity and hydrogen. If appropriated, this plant would be sited at the Idaho National Engineering Laboratory.

Incentives are also provided for integrated gasification combined-cycle plants and other “clean coal” technologies. These include an investment tax credit (capped to support about three gasification projects) and loan guarantees.

The development of wind capacity at a greatly accelerated rate in response to the extended production tax credit could affect the resource acquisition recommendations of the Plan. Further analysis would be needed to establish possible effects.

FERC Order 888 Review

FERC has begun a review of its pro forma open access transmission tariff (OATT) adopted in Order Nos. 888 and 889 in 1996. This is important because the OATT applies directly to all investor-owned utilities (called "public utilities" in the Federal Power Act) and has largely been adopted, as a result of reciprocity provisions for open access service in Order 888, by the major publicly owned transmission owners, including Bonneville. This paper will highlight two areas in the proposed OATT that are relevant to the Council's planning efforts.

In May 2006, FERC issued a Notice of Proposed Rulemaking (NOPR) to amend the pro forma OATT that was established in FERC Order 888. One of the most significant reforms proposed in the NOPR is the requirement for coordinated, open and transparent transmission planning by transmission providers subject to the OATT requirement. The NOPR proposes that each transmission provider's planning process meet eight planning principles set forth in the NOPR. These are coordination, openness, transparency, information exchange, comparability, providing dispute resolution, regional coordination, and performing congestion studies:

- Coordination: The transmission provider must meet with all its transmission customers and interconnected neighbors to develop a transmission plan on a nondiscriminatory basis.
- Openness: Planning meetings must be open to all affected parties.
- Transparency: The transmission provider must disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie its transmission plans.
- Information Exchange: Customers are required to provide information regarding needs on a comparable basis (planning horizon and format) as used by transmission providers for their native loads. Market participants must have the right to review draft transmission plans.
- Comparability: The transmission provider must develop a plan that meets the specific service requests of its transmission customers and otherwise treats similarly situated customers comparably in transmission plans.
- Dispute resolution: The transmission provider must propose a dispute resolution process.
- Regional Coordination: The transmission provider must coordinate with interconnected systems to 1) share system plans to ensure they are simultaneously feasible and otherwise use consistent assumptions and data and 2) identify system enhancements that could relieve significant and recurring transmission congestion. FERC encourages such coordination to be across as broad a region as possible.
- Congestion Studies: The transmission provider must annually prepare studies identifying significant and recurring congestion and post them on its OASIS. The studies should report on location and magnitude of the congestion, costs of the congestion, possible remedies, and the cost associated with relieving it through system enhancements or other means.

These requirements, particularly the last two, would provide additional support for the sub-regional and WECC-wide planning efforts that will provide a framework for achieving Action TX-1 ("The Council will work with Bonneville, other transmission providers, permitting agencies, and project developers to plan for long-distance transmission needs to support the resource development called for in the power plan."). FERC has made positive comments about the WECC planning framework in the NOPR, and there are efforts to get FERC to formally recognize it as satisfying, in whole or in part, the providers' obligations under the NOPR.

A second significant reform proposed in the NOPR is a proposed modification of the generation imbalance charges to reduce significantly the penalties that could be imposed on intermittent generators like wind turbines. Generator imbalance charges are charges for differences between scheduled and net real-time generation, imposed to assist control areas in maintaining system frequency by creating incentives for generation operators to maintain schedules. Because they were intended to create an incentive, imbalance charges were often artificially high compared to the control area operator's cost of remedying the situation. This was less of a problem when most generation was actually more controllable than it is becoming, with increasing amounts of desirable, but uncontrollable, wind generation in the mix.[2]

FERC suggests for further comment a schedule of imbalance charges like Bonneville's, in which relatively large deviation bands from schedules are associated with imbalance charges that are at or relatively close to the transmission provider's incremental or decremental cost of providing the imbalances itself, rather than narrow deviation bands with punitive charges for exceeding them. Further, the example Bonneville tariff exempts intermittent resources from the third (and most burdensome) deviation band and associated charges.

States

Idaho

In 2005 the Legislature created an Energy, Environment and Technology Interim Committee. One of the Committee's tasks is updating the State Energy Plan. With the input from numerous subcommittees over the last two years, the Interim Committee released an outline of the draft energy plan recommendations and action items that are being worked on. The recommendations apply to electricity, natural gas, petroleum and transportation fuels, energy facility siting, and implementation. The Interim Committee is expected to meet once more to finalize the recommendations and then present the final document to the appropriate Legislative Committees for consideration.

Among some of the recommendations are: tax incentives and exemptions for investments in energy efficient technologies; tax incentives for investments in renewable and CHP facilities; adoption of the International codes on a three-year cycle; "decoupling" of utility revenues from sales; PUC-established annual conservation targets for IOUs; conservation and renewables should be first and second priority when acquiring new resources; 25 percent of Idaho's energy be provided by renewables by 2025; provisions for money to monitor the State Energy Plan and provide statewide education on code and above-code programs; encourage technologies that minimize emissions of pollutants and water consumption; investigate clean-coal technology and "next-generation" nuclear; support for transmission construction; and creation of a state agency panel to provide technical information and support to local energy siting decisions.

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[2] There were also issues of discrimination between the treatment afforded generation owned by the control area operator and independent generation, but these are less relevant to the renewable generation goals of the plan.

The state will also consider updates to its residential and commercial building codes as part of its regular code revision cycle.

Montana

On April 28, 2005, the Montana Legislature adopted Senate Bill 415, the Renewable Power Production and Rural Economic Development Act. The law requires that 10 percent of the electricity sold in Montana come from renewable sources by 2010 and 15 percent by 2015. Also on April 28, 2005, Montana Governor Brian Schweitzer signed the bill, which, in addition to the targets, calls for a renewable energy credit tracking system and leaves open the option to trade renewable energy credits outside of the state. The legislation contains a cost cap that encourages utilities to invest in renewable generation that is cost-competitive with conventional generation.

Montana will also be considering updating its residential and commercial building codes as part of its regular code revision cycle.

Oregon

In 2005 Oregon adopted efficiency standards on six additional products not covered by the Energy Policy Act of 2005. These included single-voltage external power supplies, incandescent reflector lamps, metal halide lamp fixtures, automatic commercial ice makers, commercial refrigerators and freezers, and unit heaters.

In early 2007, Oregon will be considering changes to its residential energy code. Governor Kulongoski has set a 15 percent savings goal for these revisions.

The Governor has made energy independence a cornerstone of his administration. While the 2005 Oregon legislative session concentrated on utility tax collection practices, the governor is working to develop ways to encourage renewable energy development for the 2007 legislative session.

The most ambitious proposal is for a state Renewable Portfolio Standard. The proposal requires this standard be applied to electric utilities and any energy services suppliers that serve at least 1 percent of the state's electric load, which applies to the state's three investor-owned electric utilities and the nine largest consumer-owned utilities.

The RPS sets interim targets of 5 percent of electric load by 2011, 15 percent by 2015, 20 percent by 2020, and 25 percent by 2025. Oregon's 28 smaller consumer-owned utilities that serve less than 1 percent of Oregon's total electric load must meet 60 percent of their retail load growth by the year 2025 with renewable energy.

Eligible renewable resources for both requirements include wind, solar, wave, geothermal, biomass, hydropower, and other renewable resources that were operational after January 1, 1995. Eligible resources do not have to be located in Oregon but must serve Oregon loads.

Finally, the proposal extends the public purpose charge established in legislation passed in 1999. This legislation authorized the creation of the Energy Trust of Oregon, which administers conservation and renewable energy development programs for electric utilities Pacific Power and PGE and natural gas utilities Northwest Natural, Cascade, and Avista.

Washington

Legislation (all 2006 except as noted)

The biggest impact is expected to come from Initiative 937. It requires utilities serving 85-90 percent of Washington's electricity load to develop and follow conservation plans based on the Council's methodology and achieve targets for renewable energy in 2012, 2016 and 2020. The first conservation plan is due on January 1, 2010 and the targets from that plan need to be achieved within two years. Because these first deadlines are technically after the end of the 5th Power Plan implementation period, the initiative will not directly affect the achievement of the Fifth Plan's goals. However, because the same utilities covered by I-937 will have to do IRPs under HB1010 (see next), many of them will use the Council methodology for the conservation part of their IRP as a warm-up to the 2010 deadline. Thus, indirectly, I-937 is likely to push utilities into greater compliance with the Fifth Plan's conservation goals. The initiative will also make it likely that Washington utilities will meet the conservation targets of subsequent power plans. Similarly, as utilities gear up to the meet the 2012 target of 3 percent renewables, some of the acquisition will occur in time to be counted for the Fifth Plan's renewables targets and, going forward, Washington utilities are likely to meet or exceed renewables targets of subsequent power plans.

HB1010 requires utilities with 25,000 or more customers (85+ percent of Washington load) to do integrated resource plans. The first plan must be completed by September 1, 2008. The bill should make it more likely that utilities will acquire conservation and renewable resources comparable to what is in the Council Plan.

Increased appliance efficiency standards (2005) were mostly supplanted by federal standards but will help meet the 5th Plan's conservation targets.

Siting reforms and generation incentives should slightly enhance renewables development. These reforms included:

- Raising the net-metering limit to 100 kW, 0.25 percent of utility peak (HB2352)
- Establishing state authority for transmission siting (HB1020) to pre-empt FERC's EPACT pre-emption.
- Promoting wind (and other renewables) development through expedited siting (HB2402)
- Providing biofuels infrastructure support. While most appropriations are for transportation fuels, anaerobic digesters are also eligible.

Code updates

On November 17, 2006 the Washington State Building Code Council adopted a package of amendments to the State energy code that will make elements of the code more stringent while also improving enforcement. This should yield measurable amounts of conservation and enable Washington to capture the Fifth Power Plan's goals for conservation from energy codes, bring Washington's energy code pretty much in harmony with the Council's specifications for an optimized energy code and, once again, make the Washington state energy code the most energy-efficient in the U.S..

Mercury rulemaking

The Washington Department of Ecology and the Energy Facility Siting and Evaluation Council (EFSEC) are in the midst of a joint rulemaking to establish mercury standards for coal-fired power plants pursuant to the national mercury rule established by EPA. Like many states, Washington has thus far proposed to opt out of the national cap and trade system and instead adopt more stringent mercury emissions standards. The final rule is likely to be adopted in the Fall of 2007 and will have an effect on whether the existing Trans-Alta coal plant will continue operation and whether new conventional coal or IGCC plants will be built.

Carbon Dioxide policies

A Governor's package is being developed which may have some further effect on electricity choices.

California Policy

California has undertaken a number of very ambitious policies that affect their power system. These policies could have significant effects on the planning and development options in the Pacific Northwest. Perhaps the most dramatic of these policies are the bills setting out actions the state is to take to control greenhouse gas emissions, but the state has adopted other policies as well. Some of these, such as the energy efficiency and renewable portfolio policies, will clearly contribute to meeting greenhouse gas goals. Others, such as demand response and system adequacy policies, are directed at different goals, but are likely to affect greenhouse gas emissions as well.

Greenhouse gases

Assembly Bill (AB) 32 caps the state's greenhouse gas emissions in 2010 at the levels that existed in 2000, in 2020 at 1990 levels, and in 2050 at 80 percent less than 1990 levels. The California Air Resources Board (CARB) is tasked with determining what levels existed in 1990 and 2000 and how to measure compliance with the bill's caps

Greenhouse gases and electricity generation

Senate Bill (SB) 1368 is specifically concerned with greenhouse gas emissions from electricity generation. SB 1368 requires the California Energy Commission (CEC), California Public Utilities Commission (CPUC) and the California Air Resources Board (CARB) to establish performance standards for baseload generation, which would be no worse than the greenhouse gas emissions of a combined-cycle gas turbine. Existing combined-cycle gas turbines will be deemed compliant with the standards.

Greenhouse gases and mobile sources (transportation)

The "Pavley bill" (AB 1493) called for state regulations of greenhouse gas emissions of mobile sources. The CARB has released regulations to accomplish this regulation, but is being sued by automobile manufacturers and dealers whose position is that these regulations are properly considered by the federal government, not a state.

Renewable portfolio standard

The Legislature set California's renewable portfolio standard goal at 20 percent of retail sales by 2010, increasing by at least 1 percent per year after that time to reach 33 percent by 2020. Renewable generation from outside the state is expected to qualify for credit in meeting these goals, but only if it started production after January 1, 2005. Biomass-fired generation may qualify, but the legislation directs implementing agencies to consider any emissions from the process of growing and processing the biomass fuel.

Energy efficiency

In 2004 the state established energy savings targets for the 2004-2013 period that are expected to meet more than half of investor-owned utilities' incremental demand. In 2005, the CPUC authorized plans and $2 billion in funding for 2006-2008. This effort was estimated to save more than $5 billion in the long term and "eliminate the need to build three large power plants over the next three years" as well as reduce greenhouse gas emissions by an amount equivalent to 650,000 cars.

Demand response (DR)

The CPUC/CEC goals for demand response are to accomplish 5 percent price-sensitive DR (over and above "demand response achieved by emergency programs") by 2007.

In 2006 the expected DR of all types available for the summer peak period was over 1,800 MW. Planned programs include interruptible contracts, demand bidding, air conditioner cycling, critical peak pricing, and other alternatives. The 2006 figure is an increase of 225 MW over that for the summer of 2005.

DR - Advanced metering infrastructure

It is widely appreciated that improved meters are necessary to the success of many demand response proposals. Pacific Gas and Electric has approval with full deployment of new meters for both gas and electricity. San Diego Gas and Electric has applied for similar approval, with a decision by the CPUC on approval expected in March 2007.

DR - Retail rate structure

Critical peak prices are available to all IOU customers with peak demand greater than 200 KW, though participation is low.

Adequacy/reserve planning

California now requires investor-owned utilities to maintain 15-17 percent reserved margins throughout the year. Other utilities are required to report their supply circumstances to the CEC.

Public interest research

California has a Public Interest Energy Research (PIER) program that awards up to $62 million per year to researchers working on topics related to electricity provision and use. Further work up to $12 million per year is funded for natural gas related topics, including efficiency, environmental quality, and renewable sources of methane.

Transmission

California recognizes that planning and permitting of electricity needs improvement, but still lacks a formal process to plan transmission corridors in advance of need. The CEC has recommended that the Legislature grant the CEC transmission permitting authority and the authority to establish a statewide corridor planning process.

In 2005 Southern California Edison proposed to the FERC that a new category of transmission facility, a "renewable-resource trunk line" be created, that would connect a large concentration of renewable generation resources (for example, the Tehachapi area wind resource) to the existing grid. The intent was to make possible the provision of transmission to an area whose generation would not develop in one step, but would eventually fully utilize the transmission capacity once it was available. The FERC denied the proposal, but the CEC recommended that the CEC, CPUC and the California Independent System Operator (CAISO) work to change the CAISO's tariff to encourage renewable generation interconnections. The CAISO released a proposal for comment in June of 2006.

Implications of California's policies for the Pacific Northwest

The Pacific Northwest's power system is strongly connected to that of California, and so policies that affect California's power system in a significant way are likely to affect ours as well.

To the extent that California's greenhouse gas goals are met by energy efficiency, we may benefit from the large scale demonstration of new technologies, but we may also find that we have to compete for the time of experts and specialized firms who are assisting in California's efficiency work.

To the extent that California's greenhouse gas goals are met by renewable resources, we may have to compete with California for good sites, even in our region, and for the hardware such as wind machines, which are currently in short supply. This competition may well make it more expensive to meet our own renewable energy goals.

To the extent that California maintains an adequate reserve margin, it makes the whole Western Interconnection more secure, although that may also make it more attractive for another party to "lean on" the rest of the system by skimping on their own reserves. This principle applies to all components of adequacy, including demand response -- if California had not exercised more than 1,000 MW of demand response during the heat storm around July 24, 2006 utilities in the Pacific Northwest would have had an even more difficult task of finding sufficient resources to meet load.

In summary, California policies may provide benefits or impose costs on the Pacific Northwest; we need to continue to pay attention to their development and be ready to respond appropriately.

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