Northwest Power and Conservation Council

July 26, 2012

MEMORANDUM

TO: Power Committee Members

FROM: Charlie Black, Power Planning Division Director

SUBJECT: Narratives on Developments Since the Sixth Power Plan

For the Mid-Term Assessment, we are identifying and investigating significant developments that have occurred since the Council's Sixth Power Plan was developed. This 'situation scan' will help to determine whether, how and to what extent conditions may now be different from what was assumed in the Sixth Plan. It will also provide information that can give useful context to the other analyses that are being prepared for the Mid-Term Assessment.

The situation scan will be composed of written narratives that address a number of specific topics. The first attachment to this memo provides the current list of topics for the narratives. Additional attachments provide draft examples for two of the narratives.

A more complete set of narratives will be provided for discussion at the Power Committee meeting on August 7.

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Northwest Power and Conservation Council
Sixth Power Plan Mid-Term Assessment

Situation Scan

Introduction

Narratives

A. Regional Economic Conditions
B. Electricity Demand
C. Natural Gas Markets and Prices
D. Emissions Regulations and Impacts
E. Developments Affecting Imports from California
F. Demand Response Activities
G. Implementation of BPA Tiered Rates
H. Wholesale Power Markets and Prices
I. The Region's Utilities Face Varying Circumstances
J. Energy Efficiency Achievements
K. Renewable Resources Development
L. Acquisition of Conventional Generating Resources
M. Capacity/Adequacy/Flexibility Constraints
N. Power and Transmission System Planning
O. Power and Natural Gas System Planning

Introduction

To give the Sixth Power Plan Mid-Term Assessment greater relevance and meaning, a situation scan has been prepared. This situation scan is presented in the form of a series of narratives that describe recent events and compare them with corresponding assumptions, forecasts, and results from the plan.

The purpose of the narratives is to help make sense of the region's complex power system and the issues we face. Keeping the big picture in mind, they provide a concise summary of what the Sixth Power Plan predicted, what has actually happened so far, and the broader trends influencing events. While providing context, they also focus on prominent topics of concerns in the energy community today.

The narratives demonstrate that the plan's assumptions, forecasts, and conclusions have been reasonably accurate to date, with some exceptions. While the region's economy continues to be hampered by sluggish employment numbers, electricity demand has begun to rebound to pre-recession levels. Most notably, 81 percent of the demand growth in 2010-2011 was met with new energy efficiency resources. The region's pace of acquiring energy efficiency has exceeded the plan's expectations, and if it continues, the region will be closer to reaching the plan's high-end target of 1,400 average megawatts at the end of the five-year action plan period.

The decline in natural gas prices, thanks to new shale gas supplies, has made gas-fired generation more cost-effective, and increasingly, coal-fired generation is being displaced by it. Although the plan's natural gas price forecasts noted the shale gas phenomenon and have been reasonably accurate, the Council adjusted its price forecasts downward in August 2011 and most recently in July 2012.

Another significant change from the plan's expectations concerns the direction of emissions regulation. The momentum to reduce greenhouse gas emissions through federal legislation and other wide-scale initiatives has fallen off, although state policies remain unchanged. Increasing regulation of emissions other than GHG, the costs to retrofit or refurbish aging coal plants, as well as ample supplies of natural gas, have all but eliminated the cost advantage that coal-fired generation has traditionally enjoyed.

A. Regional Economic Conditions

Forecasts used for the Sixth Power Plan showed the region's economy growing at a fairly healthy pace, consistent with long-term historical trends. However, actual results for key economic indicators such as regional employment, construction activity, and personal income were lower during 2010-2011 than predicted in the plan. These results reflect the widespread and lasting impacts of the Great Recession, which began in 2008.

Recent economic news indicates that employment and job creation in the Pacific Northwest remained sluggish during 2010-2011, going from 6.11 million jobs in 2009 to 6.14 million jobs in 2011. However, the overall regional demand for electricity has begun to rebound and has nearly returned to pre-recession levels.

During the last two years, gross state product (expressed in constant 2005 dollars) for Idaho, Montana, Oregon, and Washington increased from about 544 billion dollars in 2009 to about 581 billion dollars in 2011, a net increase of 36 billion dollars. Based on these figures, the regional economy grew at a nominal annual rate of 3.3 percent per year during 2010-2011.

Sectors with economic growth during the last several years included durable goods manufacturing, information technology, health care, and technical services. Declining sectors included construction, mining, transportation, wholesale trade, and government services. Overall, these changes are consistent with an ongoing general structural shift in the regional economy away from energy-intensive industries and toward less energy-intensive industries.

Economic conditions also vary within the region. For example, metropolitan areas with diverse economic bases tend to fare better than rural areas, which have traditionally been more dependent on specific industries.

Another prominent aspect of the regional economy is that many state and local governments are facing severe financial pressures. Tax revenues are far below pre-recession levels. Employment in the government sector has been falling, while the availability and funding of government-sponsored programs have become more constrained.

During the last several years, aggressive federal monetary policy has pushed interest rates down to historically low levels. For example, the yield for 10-year U.S. Treasury securities averaged 3.0 percent during 2010-2011. However, access to borrowing is quite limited as banks and other financial institutions have significantly tightened their credit requirements.

The future economic outlook is very difficult to predict with any degree of certainty. While overall regional economic conditions have shown some improvement recently, the recovery has largely been a jobless one. Further, global financial instability and other factors have the potential to suppress economic activity in the U.S. and the Pacific Northwest.

B. Electricity Demand

During 2010-2011, total regional demand for electricity grew by 634 average megawatts. In 2011, regional demand on a weather-adjusted basis, and before accounting for new energy efficiency resources, was 20,735 average megawatts (excluding direct service industries). This was near the low end of the forecast range (20,644-21,690 average megawatts) for 2011 in the Sixth Power Plan.

Of this increase, 516 average megawatts, or 81 percent of growth, was met with new efficiency resources. The net increase in regional electricity loads during the last two years was 118 average megawatts.

Overall regional loads appear to be gradually returning to pre-recession levels. On a weather-adjusted basis, total regional loads (excluding DSIs) reached a high of 20,477 average megawatts in 2008, and then fell to 20,152 average megawatts in 2010. In 2011, regional weather-adjusted loads recovered to 20,219 average megawatts. If recent trends continue, regional electric loads are likely to reach pre-recession levels in about 2014.

During recent years, the residential, commercial, and industrial sectors have all experienced modest growth in demand for electricity. Growth has also been spread among the region's major balancing authorities, including BPA, investor-owned utilities, and larger public utilities.

One of the newer segments contributing to demand has been data centers. Custom and mid-tier data centers have been attracted to the Pacific Northwest by financial and tax incentives, low electricity prices, and a skilled professional base.

Another new potential source of demand is plug-in electric vehicles. Although this market segment is currently very small, it has the potential to increase regional demand.

Future growth in overall regional electricity demand is uncertain and will depend heavily on factors such as economic conditions. If economic conditions improve, demand can be expected to continue to recover. However, if the economy remains sluggish, growth may continue to remain below the levels forecast in the Council's Sixth Power Plan.

The diurnal shape of regional electric loads appears to be undergoing some change. In particular, loads during the graveyard hours from midnight to 4 a.m. are expected to increase by about 1,000 average megawatts by 2017. To the extent this occurs, it may help to relieve the oversupply conditions the region has been experiencing during the spring.

C. Natural Gas Markets and Prices

When the Council adopted its Sixth Power Plan in early 2010, market prices for natural gas had just dropped dramatically. U.S. average wellhead prices for natural gas, which averaged $7.75 per million Btu in 2008, fell by more than half to $3.57 per MMBtu in 2009.

The rapid decline in natural gas prices was the result of the unanticipated, yet massive, transformation of the natural gas industry in the late 2000s. This change was driven by the sudden emergence of the huge potential to produce natural gas from shale formations using hydraulic fracturing techniques.

The Sixth Power Plan emphasized that market prices for natural gas are subject to significant volatility, both in the short term and over longer periods of time. The advent of shale gas provides a real-world demonstration of such uncertainty; in this case in the downward price direction due to a major increase in supply. At other times, upward movements in natural gas prices have been triggered by reductions in supply or increases in demand.

To a large degree, the natural gas price forecasts used in the Sixth Power Plan reflect the shale gas phenomenon, and they have been reasonably accurate during the first two years of the planning period. The plan's medium case forecast showed U.S. wellhead prices of $4.60 per MMBtu in 2010 and $4.97 per MMBtu in 2011. These forecasts were somewhat higher than actual market prices, which averaged $4.35 per MMBtu in 2010 and $3.80 per MMBtu in 2011.

During 2012, market prices for natural gas have been rising. This is the result of several factors at the national level, including increasing demand from natural gas-fired generating facilities. Increasingly, coal-fired generation is being displaced by natural gas-fired generation. Gas to coal fuel switching is partly the result of environmental concerns, but it also reflects changed economics. In particular, it appears that lower market prices for natural gas are combining with higher market prices for coal to make natural gas-fired generating facilities more cost-effective. Another apparent factor is that after the rush to develop new shale gas supplies, gas developers are adjusting their activities in ways that are moving the overall supply-demand equation into better balance.

The Council has issued two updates to its natural gas price forecasts, first in August 2011, and again in July 2012. Each update adjusted the forecasts downward: For the forecast year 2014, the Sixth Power Plan used a base case U.S. wellhead price forecast of $6.13 per MMBtu; the 2011 update lowered this to $5.07 per MMBtu; and the 2012 update further lowered it to $4.45 per MMBtu.

D. Emissions Regulations and Impacts

When the Council issued its Sixth Power Plan in early 2010, federal legislation to reduce emissions of greenhouse gases, including from fossil-fueled electric generating facilities, was actively being developed in Congress. Other broad-scale GHG-reduction efforts were also underway at that time, such as the Western Climate Initiative, which at one point included three Northwest states along with California, several other Western states and four Canadian provinces.

Since 2010, momentum to regulate GHG emissions has slowed. A federal law regulating GHG emissions was ultimately not passed. Future regulation of GHG emissions through new federal legislation remains a possibility, but its timing and likelihood now appear uncertain. Today, California is the lone remaining U.S. state participating in the Western Climate Initiative. California had been scheduled in 2012 to implement a GHG cap-and-trade program to meet the requirements of Assembly Bill 32; startup has been delayed to 2013.

Meanwhile, it has recently become apparent that other policies, initiatives, and market developments have the potential to accomplish the objective of reducing GHG emissions, particularly from the electric utility sector. Further, much of the focus of these changes is centered on coal-fired generation and an increasing reliance on natural gas-fired generation.

For example, state policies have all but eliminated construction of new coal-fired generating facilities as an option for meeting future resource needs. Further, in December 2011, the U.S. Environmental Protection Agency issued new regulations that require existing power plants to limit emissions of mercury, arsenic, and other toxic air pollutants. Owners of coal- and oil-fired generating units greater than 25 megawatts will have four years to modify their facilities to meet specific mercury and air toxics standards (MATS).

Several factors magnify the impacts of air emissions regulations on coal-fired generation. These factors include:

- Burning coal produces larger quantities of toxic air pollutants than other fossil fuels such as natural gas.
- The quantity of carbon dioxide emitted per megawatt-hour of power generated at an existing coal-fired power plant is roughly two and one-half times as much the emissions from a modern combined-cycle natural gas-fired combustion turbine power plant.
- Coal-fired generation represents about one-third of the nation’s generating capacity, and until recently met nearly half of annual power supply needs.
- A significant portion of the nation’s fleet of coal-fired generating facilities is more than 30 years old; many of these units would require refurbishment to continue operating over the long term.

Recently, coal plant retirements totaling nearly 25,000 megawatts of capacity have been announced at the national level; this amount is expected to grow. To a certain extent, the retirements are due to the increasing regulation of non-GHG emissions and the costs to retrofit existing coal plants, including for the EPA MATS. However, retirements are also being driven by the age of many existing plants and the need to refurbish them. In addition, as coal prices have risen over the last several years and natural gas prices have dropped, the operating cost advantage that coal has traditionally enjoyed has shrunk.

Many utilities are comparing go-forward costs for their existing coal plants with the costs of new natural-gas-fired combustion turbines, and are concluding that replacing older coal-fired generation with new gas-fired generation makes sense. The prospect of future GHG regulations, with the costs and risks they pose, further tip the analysis in favor of retiring certain older coal-fired units.

Here in the Northwest, the pending retirements of two existing coal-fired plants have recently been announced. The 550 megawatt Boardman plant is now scheduled to shut down by 2020, avoiding the nearly $500 million in upgrades that would have otherwise been required. At the 1,340 megawatt Centralia plant, one unit is now scheduled to close in 2020 and the other is scheduled to close in 2025.

For the Sixth Power Plan, analysis was performed to address the impact of a carbon tax of $45 per ton and a coal retirement scenario in which about half the region's coal generation was retired. The coal retirement scenario was reasonably consistent with the announced retirements of the Boardman and Centralia coal plants.

As existing coal-fired power plants are shut down and replaced with natural gas-fired generating power plants and other resources such as renewables, net reductions in GHG emissions are expected to occur. For example, a recent study indicates that if one-third of the national fleet of 316,000 megawatts of coal-fired generation is shut down and replaced with less carbon-intensive resources by 2020, the GHG-reduction goals of the previously-attempted federal legislation would be achieved.

The trend toward retiring existing coal-fired power plants across the U.S. is having other spillover effects on the Northwest region. As domestic coal-fired generation falls, coal producers are turning their attention to offshore markets as a way to continue production from their mines. This includes major companies with coal production in the Powder River Basin of Wyoming that have recently ramped up efforts to market their coal to Asian markets and are seeking to ship coal through the Northwest to export terminals near the coast.

Meanwhile, locally-centered efforts to reduce GHG emissions are also underway in the Pacific Northwest. Cities and counties that have climate policies or initiatives include: Seattle, Anacortes, Bellingham, King County, Olympia, and Whatcom County in Washington; Portland, Bend, Corvallis, and Multnomah County in Oregon; Boise, Idaho; and Bozeman, Helena, and Missoula in Montana.

E. Developments Affecting Imports from California

The Northwest and California are interconnected through AC and DC transmission interties with approximately 7,000 megawatts of maximum transfer capability. The two regions use the lines to share their power resources to help keep costs down. Because California's peak loads occur in the summer, that system normally has surplus capacity during the winter when overall Northwest loads peak.

The actual amount of south-to-north intertie transfer capability is a function of transmission loading in both regions and also transmission maintenance. For reliability purposes, the Resource Adequacy Forum uses a conservative assumption based on actual minimum observed winter transfer capability from 2006-2010. This approach has established an assumed winter south-to-north transfer capability of about 3,200 megawatts.

For resource adequacy assessments, the size of the market for imports from California is assumed to be either: a) the remaining amount of south-to-north intertie transfer capability; or b) the amount of excess firm generating capacity available from California—whichever is smaller.

The Sixth Power Plan reflected the Resource Adequacy Forum's assumption of 3,200 MW and assumed that California will have at least this much surplus generation in the winter. In other words, generating capacity from California was not expected to be the limiting factor for imports to help meet winter peak needs in the Northwest.

However, a number of changes have occurred in California since the Sixth Power Plan was developed that have the potential to reduce the availability of winter imports to the Northwest, and could increase the need for new resources.

The first major change has to do with existing power plants in the coastal areas of California that use water in cooling processes. These plants are subject to the federal Clean Water Act that requires using the best technology available in power plant cooling processes. In May 2010, the California Water Resources Board adopted a statewide water quality control policy on the use of water for cooling to implement section 316(b) of the Act. This regulation is expected to force about 4,800 megawatts of older California generating plants into retirement by 2017.

With these plant retirements, the estimated amount of surplus generation available from California during winter on-peak periods drops to about 1,700 megawatts (i.e., south-to-north intertie capacity availability is no longer the limiting factor).

Also affecting the California market, both units at the San Onofre Nuclear Generating Station (about 2,200 MW of nameplate capacity) were taken out of service in January 2012 due to excessive wear in steam generator tubes. It is not clear whether or when this major source of generation will be come back on line. If the San Onofre plant remains out of service for an extended period or is permanently retired (its license expires in 2022), the estimated amount of surplus generation available from California during winter on-peak periods drops to zero.

Another major factor is California's increasing reliance on renewable resources to meet its energy needs. In 2011, the California legislature passed a law requiring the state's utilities to serve 25 percent of their retail customers' loads with qualified renewable resources by 2016; this requirement increases to 33 percent by 2020. The law also established new policies limiting the use of renewable generation from outside California to meet the requirements. Many California utilities are already serving 20 percent or more of their customers' needs with renewable energy. During the last couple of years, the trend has been to increase solar power development, as costs for photovoltaic systems have been falling rapidly. California's move to use more renewable resources has the potential to affect the availability of surplus generation to help meet winter peaking needs in the Northwest. Research and analysis will be required on this topic.

F. Demand Response Activities

The Sixth Power Plan did not call for the region to develop demand response resources in program quantities. Instead, it laid out a number of actions designed to keep the region abreast of developments in other parts of the U.S., to demonstrate the potential for DR in the Pacific Northwest, and to explore its potential to provide regulation and load following services beyond peak-load reduction, its traditional focus.

Since the plan's adoption, there has been significant progress in many areas identified in the plan. The two regional utilities with the most experience in acquiring and using demand response, PacifiCorp and Idaho Power, have continued to expand and refine their programs. Both are now exercising control over more than 5 percent of their peak loads, totaling nearly 1,000 megawatts of DR. Both are planning further increases.

While other regional utilities have not acquired DR to this extent, some are gaining experience with it. PGE has contracted for 16 megawatts of DR in the industrial sector and has 50 MW planned but not yet operational from the commercial sector. Puget Sound Energy and Avista have both conducted demand response pilot programs. Neither of these utilities is acquiring DR currently, but PSE expects that DR will be competitive for their peak capacity needs if its price from generating facilities rises.

BPA has launched an extensive pilot program in cooperation with 14 of its utility customers, testing the potential of both traditional DR (peak reductions) and new DR that could help integrate wind generation and other renewable generation. BPA has also arranged 35-70 megawatts of contingent reserves provided by ALCOA's aluminum smelter.

Outside the region, the Federal Energy Regulatory Commission has taken a number of steps to put DR on an equal basis with generation in providing capacity and ancillary services. Some representatives of independent system operators have discussed a goal of meeting their needs for regulation services entirely from managed load (DR) in the next 10 years.

Idaho Power has modified the incentive structure of its irrigation DR program, decreasing the fixed share of the incentive and sharing some of the risk with irrigators that a mild summer will not require as much DR use. The Pacific Northwest Demand Response Project hosted a discussion of how to evaluate energy efficiency and demand response in industrial facilities. The tradeoffs between DR and energy efficiency have come to be recognized and discussed.

In some cases, DR can be acquired in coordination with energy efficiency, sharing the costs of analysis and administration, making both resources more attractive. In other cases, managing energy use to provide DR may use more energy, so evaluating the relative cost and value of DR and energy efficiency is critical. A current example of this kind of tradeoff dilemma is the proposal before the Department of Energy to exempt some large capacity water heaters from the requirement that they use heat pumps if they are part of a utility DR program.

G. Implementation of BPA Tiered Rates

In October 2011, the Bonneville Power Administration implemented tiered rates for its sales of wholesale power to the region's public utilities. BPA's tiered rates are designed to allocate the benefits of the existing federal power system and provide more direct price signals about the costs of new resources to meet load growth.

Under tiered rates, BPA's power sales are divided into two distinct blocks, or tiers. The rate for tier 1 power sales is based on the embedded cost of the existing federal power system. The tier 2 rate is set at BPA's cost to acquire power supplies from other sources. When a utility customer exceeds its allocation of tier 1 power, it can elect to buy tier 2 power from BPA, or it can acquire new resources itself. The alternatives include utility development of new energy efficiency and/or generating resources, as well as wholesale power purchases from third party suppliers.

Currently, the average cost of BPA's tier 1 power is roughly $30 per megawatt-hour. This is below the typical cost to develop new resources, particularly new power generating facilities. So to a certain extent, tiered rates are achieving the intended purpose of providing more efficient pricing signals to BPA's utility customers.

However, several factors may be muting the price signal effects of BPA's tiered rates.

For example, only 34 of BPA's public utility customers are projected to exceed their tier 1 allocations by 2015; most are not expected to exceed their tier 1 allocations and won't be exposed to the tier 2 price signal. But the prospect of paying them in the future may already be influencing their behavior. There is anecdotal evidence that some utilities are taking action to avoid exceeding their right to purchase power at tier 1 rates.

Secondly, prices for wholesale power purchased in the wholesale market have recently been relatively low, often below the cost of new resources or even below BPA's tier 1 rate. While spot market prices can be quite volatile, the addition of large amounts of new renewable resources with low variable operating costs has contributed to low spot market prices. To the extent that BPA or utilities purchase power in the short-term market to meet their incremental resource needs, this also mutes the tier 2 price signal.

Finally, there is also the matter of whether and how the price signal provided by BPA's tiered rates is passed through to each utility's retail electric customers. Retail customers are the end-users of electricity; their behavior affects load growth and load shapes. Utilities could influence their retail customers to reduce their total use of electricity and their peak demand by modifying their retail rate structures, by designing and executing energy efficiency and demand response programs, or a combination of these policies. So far, there is some anecdotal evidence that this is happening, but BPA's tiered rate methodology has been in force for less than a year. Utility responses can be expected to develop over time, and are likely to mitigate growth in energy use and peak demand.

H. Wholesale Power Markets and Prices

Analysis for the Sixth Power Plan emphasized the volatile and uncertain nature of key inputs, including forecasts of market prices for wholesale power supplies. The plan and its resource strategy were explicitly designed to account for the reality that market conditions change dynamically through time, so no point forecast of wholesale power prices can be relied upon to be correct, accurate or an adequate basis for making long-term commitments to new electric resources. Nevertheless, as the region moves forward in implementing the plan's resource strategy, it is useful to compare actual conditions with the range of price forecasts used to develop it. Review of what has been happening since early 2010 also provides context for the near-term signals that current market prices are sending to utilities, resource developers, consumers, and others.

For the Sixth Power Plan, three factors were identified as being likely to significantly influence future conditions in wholesale power markets: market prices for natural gas; potential new regulatory requirements for generating resources that emit greenhouse gases; and development of renewable resources to satisfy requirements of state renewable portfolio standards. A range of forecasts of wholesale power prices was then prepared using alternative assumptions about these factors.

Since the plan was adopted in early 2010, new developments have occurred on all three fronts. First, the supply-side impacts of shale gas have continued unfolding, causing market prices for natural gas to remain at lower than previously expected levels (see Narrative C). Second, while momentum to impose federal carbon taxes or other regulatory mechanisms to reduce greenhouse gas emissions has slowed, other forces appear to be helping to at least partially accomplish overall GHG-reduction goals (see Narrative D). Third, renewable resource development in the Northwest has exceeded pace shown in the plan, adding new generating resources whose output is subject to variability.

The development of large amounts of new renewable resources that have low or zero variable operating costs also appears to be affecting the fundamental nature of wholesale power markets. Because the Northwest already has large supplies of hydroelectric generating resource whose variable operating costs are negligible, this is helping drive spot market prices for wholesale power down to very low levels more often.

These and other factors (e.g., continued slow economic activity, modest growth in demand for electricity) have caused actual spot market prices for wholesale power supplies during the last several years to be at or even below the low end of the range of forecasts used for the Sixth Power Plan. For example, actual spot market prices for wholesale power supplies bought and sold at the Mid-Columbia trading hub averaged about $20 per megawatt-hour during July 2011 – June 2012. In contrast, average prices for calendar year 2008 were more than 250 percent higher.

The low spot market prices for power are causing quite uneven impacts across the region's utilities. Utilities with limited exposure to market prices may be largely unaffected. For example, utilities whose resources closely match their customers' demands have little need to buy or sell power in the wholesale spot market. On the other hand, utilities whose resources and loads are not as closely balanced can be greatly – and very differently – affected depending on whether their resources are surplus or deficit.

Some of the region's hydro-based utilities have surplus power supplies at certain times of the year and are dependent on revenues from sales of their excess power into the wholesale market as an important means to keep rates low. These utilities can experience significant revenue shortfalls and budgetary pressures when wholesale market prices are low. For hydro-based utilities, the impacts are magnified if the surplus energy they have to sell during the spring runoff coincides with surplus generation from other hydro systems, driving spot market prices to very low levels. This occurred during April-July 2011, when spot market prices averaged well under $15 per megawatt-hour.

Conversely, utilities that do not have enough long-term resources to meet all of their customers' loads are net buyers in the short-term wholesale markets. When spot market prices are low, their power purchase costs are also low, reducing upward pressure on their retail electric rates. Relying on market purchases can be risky as was seen during the Western Energy Crisis of 2001. However, for now, these utilities are reaping the benefits of low market prices.

For all utilities, the depressed spot market prices for wholesale power are currently below the full cost of virtually any new form of generating resource.

I. The Region's Utilities Face Varying Circumstances

Since the Sixth Power Plan was adopted in February 2010, utilities across the region have experienced a variety of challenges and successes. Some were expected and some have been new, reflecting an ever-changing environment. As a result, the needs and incentives to acquire new resources also vary among the region's utilities.

Continued economic stagnation has meant lower overall load growth than expected. Poor economic conditions have also triggered the loss of existing industrial loads as manufacturing facilities are shut down. For example, Snohomish PUD recently lost a big portion of its industrial load when customer Kimberly-Clark was forced to close its mill in early 2012.

As a result, some utilities such as Tacoma Power now find themselves with power supply resources that exceed retail customer demands. Low spot market prices for wholesale power limit the revenues generated from sales of surplus power, putting pressure on utility budgets. To the extent that a utility is also below its entitled power from BPA at tier 1 rates, they also face price signals that reduce short-term economic incentives to acquire new energy efficiency resources.

On the other hand, the region has been a hot bed for new data center loads as companies like Google, Microsoft, and Facebook take advantage of the mild climate and low electricity prices to develop facilities in the Northwest. Amazon has recently built data centers in the Umatilla Electric service territory, increasing their load substantially.

Certain utilities adding large new retail customers face the prospect of growing enough to become subject to higher state renewable requirements. These utilities may also exceed their BPA high water mark, exposing them to potentially higher prices for tier 2 power purchases from BPA.

The Boardman and Centralia coal-fired power plants will be retired in 2020 and 2025 respectively, and will eventually increase regional and individual utilities' needs for new resources.

The region acquired 254 average megawatts of new efficiency resources in 2010, exceeding the Sixth Power Plan's target of 200 average megawatts. Examples of individual utility achievements include nearly 39 average megawatts of new efficiency by Puget Sound Energy in 2010. McMinnville Power and Light actually achieved a net reduction in its load while also stimulating local economic growth by implementing energy efficiency measures.

Small and rural utilities face special challenges in acquiring efficiency resources. These include the absence of economies of scale enjoyed by larger utilities in urban areas and less availability of qualified contractors. Small and rural utilities also tend to serve areas with more severe climatic conditions. As a result, approaches to acquire energy efficiency must be tailored to meet their unique needs.

For generating resources, Snohomish PUD began producing power from its 7.5 megawatt Youngs Creek run-of-river hydro project in October 2011. It is the first new hydropower plant to come on line in Washington in 20 years. Idaho Power completed Langley Gulch, a 300-megawatt, high-efficiency combined-cycle gas-fired generating facility in June 2012. Shortly thereafter, Langley Gulch helped Idaho Power meet a new all-time system peak load.

J. Energy Efficiency Achievements

Acquisition in 2010-2011 Exceeded the Planned Pace

The Sixth Power Plan identified a range of likely energy efficiency resource acquisition during 2010-2014 of 1,100 to 1,400 average megawatts. Within this range, the plan recommended setting budgets and taking actions to acquire 1,200 average megawatts of savings from utility program implementation, market transformation efforts, and codes and standards.

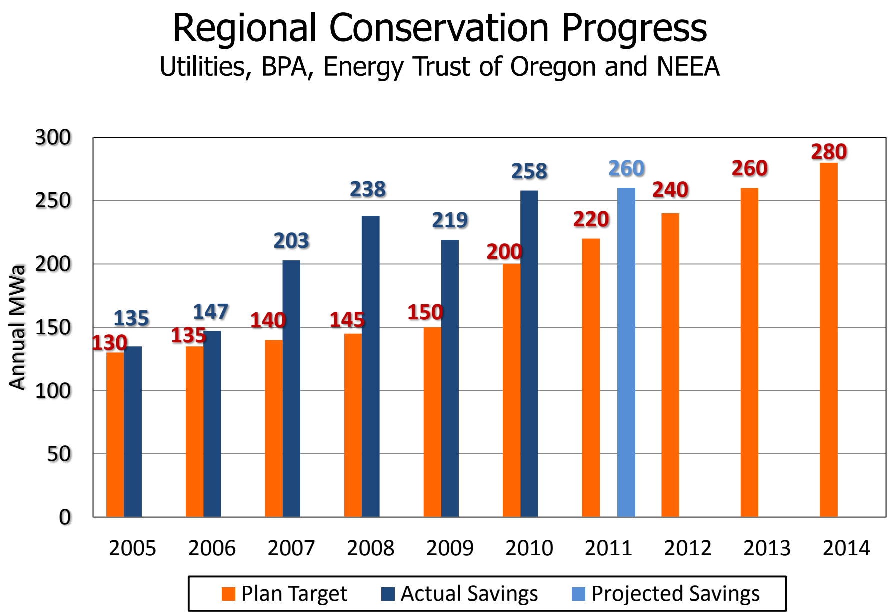
The plan estimated that the region would ramp up its pace of acquisition during the initial five-year period. Despite a sluggish economy, which limited new building construction and equipment replacement, the region's overall acquisition exceeded the Council's ramp-up expectations in the first two years.

During 2010, the region's utilities, the Bonneville Power Administration, Energy Trust of Oregon, and Northwest Energy Efficiency Alliance acquired 258 average megawatts of efficiency, 58 average megawatts more than what the plan forecast. Results for 2011 were XXX average megawatts, XXX average megawatts above the expected pace of development.

In addition to the savings acquired by the utilities, BPA, ETO and NEEA, all four states recently adopted new building energy codes. NEEA has estimated state code-based savings at about 1 average megawatt over the last two years, which should increase as the economy recovers.

At the federal level, the U.S. Department of Energy has issued final efficiency standards for 17 products since 2009, many of which count toward the Council's targets. The Council estimates XXX average megawatts of savings from the new federal standards over the five-year target period. Long-term savings from federal standards adopted since the plan was developed will likely achieve XXX average megawatts over the 20-year forecast period--about XX percent of the 20-year cost-effective potential.

If the region maintains the same acquisition rate during 2012-2014, the total five-year amount could be closer to the high end of the plan's range, potentially approaching 1,300 average megawatts. The pace may also indicate that the Council's assumptions about acquisition rates for retrofit efficiency were too low.



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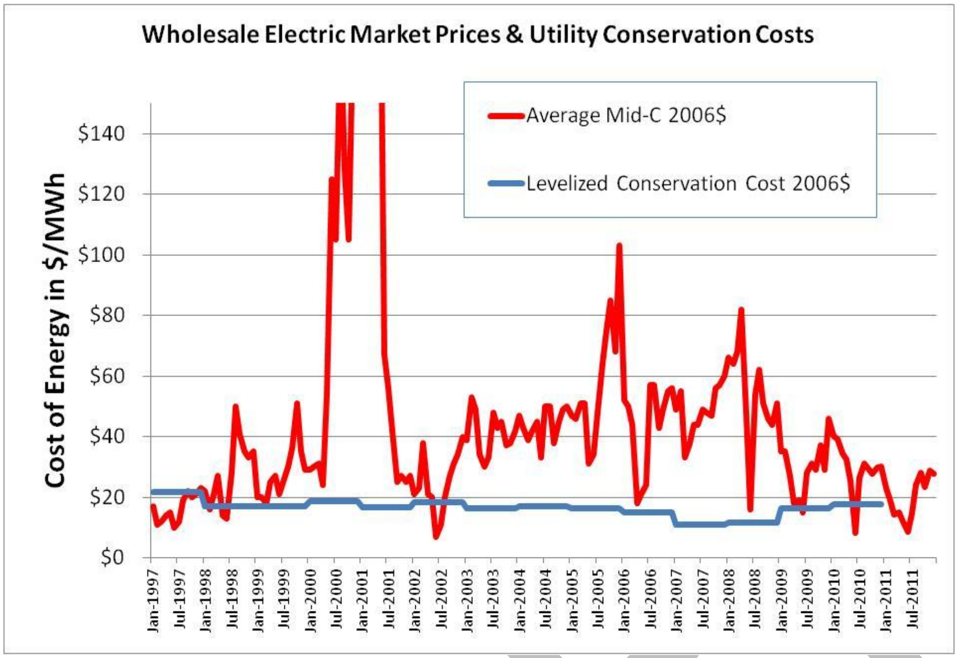
Actual Costs Have Been Lower Than Expected

During 2010-2011, the region’s utilities and the Energy Trust of Oregon spent about $400 million per year, or about 3 percent of utility system revenues to acquire new efficiency resources. The actual utility system cost to acquire savings averaged about $XX per megawatt-hour. This was lower than several important benchmarks, and well below:

- the levelized cost of $XX per megawatt-hour for efficiency used in the Sixth Power Plan
- levelized costs for all forms of new generating resources that are typically $XXX per megawatt-hour or higher
- average wholesale prices for electricity traded at the Mid-Columbia hub, which were $XXX per megawatt-hour in 2010 and $XXX per megawatt-hour in 2011.

By acquiring more efficiency than planned, and at lower than expected costs, during 2010-2011, the region’s utilities delivered greater overall economic benefits to customers and lowered risks to the power system.


Wholesale Electric Market Prices & Utility Conservation Costs
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Levelized Conservation Cost 2006$
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$120
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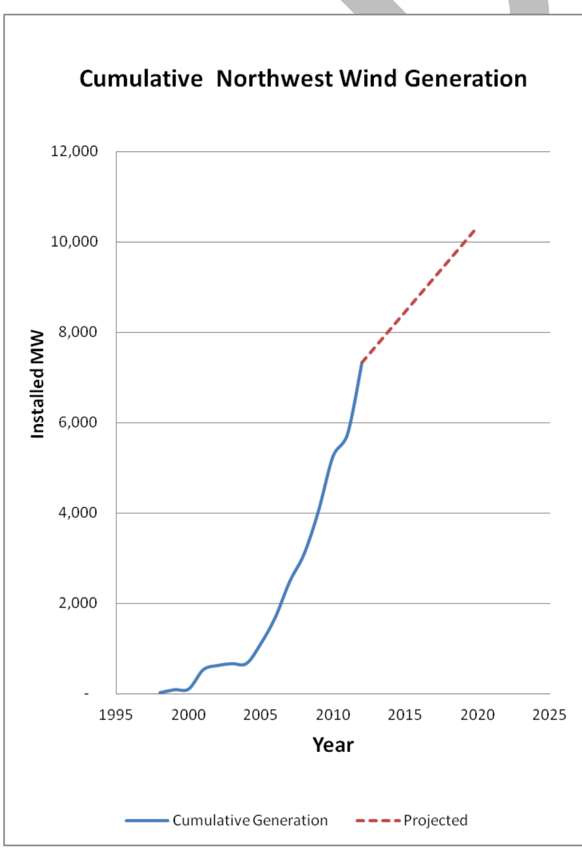
K. Renewable Resources Development

The resource strategy for the Sixth Power plan incorporated and reflected projections that the region will add over 1,400 average megawatts of renewable resources over 20 years to meet renewable portfolio standards (RPSs) that the states have enacted. The new renewable resources were anticipated to be almost wholly wind power.

During the last several years development of wind generating facilities has continued at a rapid pace, with regional capacity expected to reach more than 7,300 megawatts by the end of 2012. Development has been almost entirely to state mandated renewable portfolio standards and to a far lesser extent, utility voluntary green marketing programs.

Until recently, a considerable amount of wind power was developed in the Northwest for sale to California who are subject to that state's renewable portfolio standards. However, it is expected that few additional Northwest wind resources will be built for this purpose, despite California having raised its RPS requirement to 33% by 2020. The reason is that restrictions imposed by the California legislature in 2011 effectively block further imports from outside the state to meet RPS needs. Another contributing factor is that costs for solar photovoltaic generation have come down to the point where in-state solar is competitive with imported wind generation.

In terms of developing renewable resources to meet Northwest RPS needs, recent actual results have been generally consistent with the Sixth Power Plan. Notable differences include the following:



1. While the plan assumed renewable resources would be developed to meet 95 percent of RPS targets, recent experience suggests utilities are actually achieving their target levels a year or two in advance of the requirement.
2. Construction of renewable resources to serve the California market is now expected to slow considerably if not end completely.

<u>Integration Issues</u>

The Wind Integration Forum continues to address issues around integrating the variable and less-predictable wind energy into the power grid. Substantial progress has been made, including:

- reducing the quantity of reserves required;
- increasing access to resources capable of providing reserves; and

- developing pilot demonstration projects using demand-side resources to provide reserves.

The quantity of reserves on the BPA system dedicated to providing balancing services has remained relatively constant because of the cited progress, even as wind on the BPA system has increased. Nevertheless, the ability of the hydro system to provide balancing services varies, and at times it has dropped to near zero. At such times, wind generation or delivery schedules are limited to maintain the power system supply and demand balance. This has occurred primarily during very high flow spring months when the hydro system must pass prescribed flow levels for flood control, and environmental requirements constrain the ability to pass water over spillways. This occurs when the generation level is high and relatively fixed.

In addition to the limited ability to provide balancing services during these events, BPA has at times had trouble finding markets for its power at acceptable (non-negative) prices. It implemented a controversial policy of displacing wind resources with hydro generation under negative market price conditions when hydro turbine generating capability is available and dissolved gas levels rise above state mandated caps.

The Council convened an Oversupply Technical Oversight Committee (OTOC) to recommend actions to reduce oversupply events. The committee developed a number of recommendations to more cost-effectively deal with oversupply events. The region continues to develop methods for the efficient integration of wind generation into the grid.

Meanwhile, as noted, costs for solar photovoltaic generation have dropped dramatically during the last several years. Although solar potential is lower in much of the Northwest compared to other areas such as the Southwest, the economic and commercial viability of solar power is improving and merits further investigation.

L. Acquisition of Conventional Generating Resources

The Sixth Power Plan's resource strategy called for phased optioning (siting and licensing) of new natural gas-fired generation facilities, including up to 650 megawatts of single-cycle combustion turbines and 3,400 megawatts of combined-cycle combustion turbines. The plan's resource strategy also recognized it may be necessary to develop additional natural gas-fired generation where and when individual utilities require resources to address local capacity, flexibility or energy needs that exist for reasons not captured in the plan's regionwide analysis.

Since the plan was adopted in early 2010, the largest new natural gas-fired generating resource added in the region is Idaho Power's Langley Gulch Power Plant located near Boise. Langley Gulch is a 300 megawatt combined-cycle project that entered service in July 2012. Since it was recognized in the Sixth Power Plan as an already committed resource, gas-fired generating resources in the plan's resource strategy are in addition to it.

During the last couple of years, some of the region's utilities have issued requests for proposals to acquire generating resources. An informal survey of several of these utilities identified RFPs calling for over 3,100 megawatts of conventional generating resources, including baseload, intermediate, and peaking resources. It is likely that some of the utilities' needs will be supplied by existing uncommitted power plants located in the region. For example, in late July 2012, Puget Sound Energy and TransAlta announced they had agreed to a power sales contract that will supply baseload generation from the Centralia coal-fired plant to PSE during December 2014 to December 2025, including 380 megawatts during December 2016 to December 2024.

After the Sixth Power Plan was issued, planned retirements of several generating resources have been announced, including shutdown of the 550 megawatt Boardman coal plant in 2020 and shutdown of one unit at the 1,340 megawatt Centralia coal plant in 2020 and the other in 2025. Closure of these generating facilities creates the prospect that over the long term, it will be necessary to add resources to replace them, increasing the region's overall need for new resources.