

Northwest Power and Conservation Council

PROPOSED DRAFT

Sixth Power Plan Mid-Term Assessment Report December 14, 2012

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I. Executive Summary

The primary purpose of this Mid-Term Assessment is to check on the region's progress in implementing the Sixth Northwest Power Plan, which the Council issued in early 2010.

As an initial step in the assessment process, a Situation Scan was prepared to provide a fairly high-level survey of what's been happening during the last several years. Conditions in the region have not been static, and some things have turned out differently from what the plan anticipated. In addition, while the plan addressed the region as a whole, recent conditions and circumstances have varied widely within the region and from utility to utility.

A. Major Conclusions

Information-gathering, analysis, and conversations during development of the Sixth Power Plan Mid-Term Assessment have led to the following conclusions:

1. The region is making good progress implementing the Sixth Power Plan, and the region is well-positioned to meet the plan's five-year goal of 1,200 average megawatts of energy efficiency for 2010-2014. Actual costs for energy efficiency acquisitions have remained well below the cost of other types of new resources.
2. Development of renewable resources, mainly wind power, has continued, including for export out of the region, although changes in California's renewable policies may slow its pace. Efforts to mitigate wind oversupply events are proceeding.
3. Actual market and electric industry conditions during the first three years of the plan's implementation period have differed from expected-case assumptions: slower than anticipated economic and electricity demand growth and low market prices for natural gas and wholesale power, for example.
4. Conditions vary across the region and from utility to utility. Some have growing loads, others are flat or have lost large customers. Some have surplus resources and others face deficits. These differences affect utilities' incentives to acquire energy efficiency.
5. The Northwest power system has the lowest greenhouse gas emissions intensity of any region in the country. Recent announcements that the Boardman and Centralia coal plants will be closed indicate that the region's GHG emissions will become even lower.
6. An updated analysis shows that with existing resources and projected energy efficiency, the region's adequacy will fall short of the desired level by 2017. While new resources are expected to close this gap, the Council will continue to monitor regional resource adequacy.
7. The character of the region's power system is changing. Historically, needs for new resources were driven mostly by energy deficits. Today, however, needs for peaking capacity and system flexibility are also emerging, expanding the focus of the region's

planning and development of new resources to address peaking capacity and system flexibility.

8. Updated information is needed about the patterns of consumer uses of electricity and how they affect power system needs for energy, peaking capacity, and system flexibility. Information is also needed about how different types of energy efficiency measures could help meet these needs.
9. Spot market prices for wholesale power continue to be quite low, due to increasing penetration of renewable resources with low variable operating costs and low natural gas prices, and do not provide an accurate representation of the avoided cost of new resources.
10. Regional power supply planning matters are becoming increasingly linked with electric transmission and natural gas matters requiring greater coordination.

B. Candidate Topics for the Seventh Northwest Power Plan

1. Making the power plan useful for all regional utilities
2. Regional needs for energy, peaking capacity, and system flexibility
3. Avoided cost benchmarks to evaluate new resources
4. Energy efficiency – how can different types of measures help meet needs for peaking capacity and system flexibility
5. Changing paradigm for energy efficiency; its impact on assessing cost-effectiveness
6. Renewable resources development and integration; impacts on the regional hydro system
7. Demand response
8. Distributed generation
9. Greenhouse gas – regional emissions outlook, regulatory and social costs
10. Incorporating intra-regional transmission constraints in regional power system planning
11. Growth in use of natural gas for electric generation; intersection of planning for the regional power and gas systems
12. Inter-regional linkages, including Northwest and California

II. Situation Scan and Narratives

A. Introduction

To provide context for Sixth Power Plan Mid-Term Assessment, the Council has prepared a situation scan that surveys what has happened since the plan was adopted in early 2010. The following series of narratives describes recent events and compares them with the plan's assumptions, forecasts and results. Looking at current circumstances has helped frame the discussion about what the critical issues are, and how we as a region should address them.

The situation scan consists of narratives on the following topics:

1. Regional Economic Conditions
2. Electricity Demand
3. Natural Gas Markets and Prices
4. Emissions Regulations and Impacts
5. Developments Affecting Power Imports from California
6. Wholesale Power Markets and Prices
7. Implementation of BPA Tiered Rates
8. The Region's Utilities Face Varying Circumstances
9. Energy Efficiency Achievements
10. Demand Response Activities
11. Renewable Resources Development
12. Additions and Changes to Fossil-Fueled Generating Resources
13. Shifting Regional Power System Constraints
14. Power and Transmission Planning
15. Power and Natural Gas System Convergence

1. Regional Economic Conditions

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. 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.

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.

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.

2. Electricity Demand

During 2010-2011, total regional demand for electricity grew by 651 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, 533 average megawatts, or 81 percent of growth, was met with new energy 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 Direct Service Industries) 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 return to 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.

3. 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 \$8.19 per million Btu in 2008, fell by more than half to \$3.77 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.

To a large degree, the natural gas price forecasts used in the Sixth Power Plan reflected the shale gas phenomenon. The forecasts were 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 turned out to be somewhat higher than actual market prices, which averaged \$4.61 per MMBtu in 2010 and \$4.06 per MMBtu in 2011.

Beginning in mid-2011, monthly wellhead gas prices fell fairly rapidly, reaching a low of \$1.94 per MMBtu for the month of April 2012 before rebounding after that. Annual average prices are currently projected to average about \$2.78 per MMBtu for 2012, significantly below the plan forecast of \$4.90 per MMBtu.

More recently, the decline in market prices appears to have reversed and prices have begun increasing since April 2012. This has been reflected in steadily rising monthly actual prices, as well as increasing forward market prices. Meanwhile, the US Department of Energy is currently forecasting wellhead gas prices to average about \$3.52 per MMBtu during 2013, compared to the plan forecast of \$5.40 per MMBtu.

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.

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 was 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.

Increasingly, natural gas-fired generation is displacing coal-fired generation. Coal to gas 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.

4. 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.

5. Developments Affecting Power Imports from California

The Northwest and California are interconnected through AC and DC transmission interties with approximately 7,900 megawatts of maximum transfer capability, including 4,800 megawatts on the AC intertie and 3,100 megawatts on the DC intertie. Due to transmission loading on either end, the actual amount of transfer capability is closer to 6,000 megawatts and could be much lower if one of the lines is undergoing maintenance.

The two regions use these interties 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 Northwest loads are highest. The Resource Adequacy Forum uses a conservative assumption for the south-to-north transfer capability of the interties based on the actual minimum observed winter transfer capability from 2006-2010. This approach has established an assumed winter south-to-north transfer capability of 3,200 megawatts.

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

The Sixth Power Plan reflected the Resource Adequacy Forum's previous assumption of 3,200 megawatts and assumed that California will have at least this much surplus generation available in any hour over the winter period. 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 6,659 megawatts of older California generating plants into retirement by 2017. Other expected California resource retirements through 2017 amount to 1,030 megawatts.

A majority of the retiring capacity is being replaced with modern gas-fired generation, including combined cycle combustion turbines that are more fuel-efficient than the once-through-cooling plants and also have lower air emissions, as well as fast-responding simple cycle combustion turbines that will both provide capacity and be used to integrate renewables.

Also affecting the California market, both units at the San Onofre Nuclear Generating Station (SONGS), with 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 SONGS plant remains out of service for an extended period or is permanently retired (its license expires in 2022) – and if it is not replaced –

this could put further downward pressure on the amount of surplus generation available for import from California during the winter.

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.

Based on recent California Energy Commission data, by 2017 California is expected to add 7,734 megawatts of solar, 2,116 megawatts of wind and 1,641 megawatts of other renewable resources to yield a total of 11,491 megawatts of new renewable resource generation.

Unfortunately, wind resources don't often contribute very much toward meeting peak demands and solar generation is typically much higher during summer months – this means relatively less capacity would be available during our peak season in winter. However, if combustion turbines are used to provide within-hour balancing needs for renewable resources, some of their capacity might be available in winter for Northwest use. California is also planning to use summer-only demand response programs to help reduce its summer resource needs.

Because of the uncertainties surrounding the retirement and replacement of California resources, the Resource Adequacy Forum decided to lower the assumed availability of the California winter market supply to 1,700 megawatts for its 2017 adequacy assessment.

6. Wholesale Power Markets and Prices

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 4). 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.

7. 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.

8. The Region's Utilities Face Varying Circumstances

Utilities across the region have experienced a variety of challenges and successes in the last few years. 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.

9. Energy Efficiency Achievements and Issues

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 between 1,100 and 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.

Over the initial two years of the plan, the region's utilities, the Bonneville Power Administration, Energy Trust of Oregon, and Northwest Energy Efficiency Alliance acquired just over 530 average megawatts of efficiency, achieving 44 percent of the Plan's five-year goal. In both 2010 and 2011, acquisitions were about 50 average megawatts per year higher than anticipated in the Plan. Commercial, industrial sector savings have grown the most in recent years.

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 one average megawatt over the last two years; this amount should increase as the economy recovers and construction and remodeling activities rebound. The federal Department of Energy (USDOE) has issued final standards for 20 products since 2009. Some of these standards begin to take effect in 2012 and will produce modest additional savings in the 2012-2014 period, depending on details of their implementation market response. The federal standards are expected to produce significant savings post 2014.

Projected Savings 2012-2014

To develop projected conservation activities for 2012 -2014, the Council surveyed regional utilities, BPA, Energy Trust and NEEA. Utilities representing about 90 percent of regional load reported. Projected savings from the survey taper off from reported 2010-2011 levels indicating the high levels achieved in the last two years may not be sustained. NEEA projected savings for 2012-2014 are similar to 2010-2011 levels. Together, past accomplishments and future projections add up to about 1,200 average megawatts of savings over the 2010-2014 period, indicating the region is on track with respect to Regional Plan targets. Regional savings may surpass 1,200 average megawatts, since savings from federal appliance efficiency standards and

state energy codes that were not reflected in the Sixth Plan's load forecast and projected savings from about ten percent of utilities are not included in the survey total.

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. Even though the region exceeded the plan's expected pace of conservation acquisitions, the cost to utilities of acquiring conservation remain consistent with the Plan's expectations.

The estimated levelized utility cost of conservation acquired was \$18 per megawatt-hour. This cost of conservation acquired is at or below recent low wholesale prices of electricity and well below historical market prices¹. The cost of conservation acquired at this pace is also below most forecasts of future market prices and well below the cost of new generating resources, even at current low fuel prices. If conservation deployment at recent acquisition pace and price can be maintained going forward, the region stands to reap continued economic benefits.

Influences on Future Energy Efficiency

It appears that the region is on track to achieve the Sixth Plan's conservation goals for quantity and cost of energy efficiency. However, other factors identified in the Mid-Term Assessment, including low natural gas prices, low wholesale electricity market prices and slow or no load growth have been advanced as reasons to re-examine conservation investments. Lower market prices for electricity reduce the amount of cost-effective conservation potential somewhat, but the supply of remaining low-cost conservation potential appears large enough to provide cost-effective resource potential for many years - even at the recent accelerated pace of acquisition.

The recent economic recession has limited conservation potential in new construction and equipment replacement markets. However, the region has successfully substituted accelerated retrofit conservation that has more than made up for the difference and delivered very low cost of conservation acquisition. Low load growth at some utilities has highlighted rate pressures from near-term conservation costs. Significant reductions in conservation investments may reduce near-term rate pressures, but would also reduce both near-term and long-term cost and risk benefits of acquiring low-cost conservation resources.

Recently adopted federal appliance standards and state energy codes will capture a large portion of the long-term lost-opportunity conservation potential identified in the Sixth Power Plan. This will significantly reduce future long-term load forecasts and remaining potential for the Seventh Power Plan. The shift may make utility program savings for lost-opportunity conservation more expensive and difficult to capture unless new technologies are developed. Continued focus on emerging technologies will be increasingly important.

¹ Monthly market prices are not equivalent to the levelized cost of energy savings. However, monthly market prices are one proxy for the short-term cost of buying power instead of building conservation, as well as the value of selling surplus conservation in the short-term market. Short-term market prices are also subject to much greater volatility relative to the stable utility cost of conservation.

As the region faces increasing capacity and flexibility needs, it will become more important to identify the impacts of energy-efficiency programs on capacity needs. Improved end-use load research is needed to improve both the understanding how efficiency programs impact capacity needs, and also how underlying changes in the way electricity use patterns are influencing capacity and flexibility needs.

10. Demand Response Activities

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.

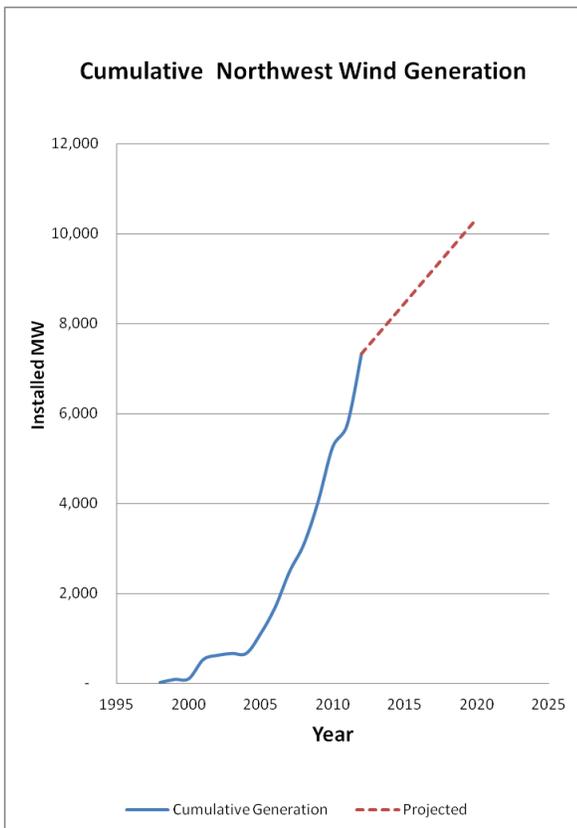
11. Renewable Resources Development

During the last several years, wind generation development 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 meet 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 utilities 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 percent 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 increasingly 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. The plan's resource strategy incorporated projections that the region would add over 1,400 average megawatts of renewable resources over 20 years to meet renewable portfolio standards that the states have enacted. The new renewable resources were anticipated to be almost wholly wind power.

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, if not end completely.

Integration Issues

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
- Developing pilot projects using demand-side resources to provide reserves.

The quantity of reserves on the BPA system to provide balancing services has remained relatively constant because of this progress, even as wind on the 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 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 to integrate 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.

12. Additions and Changes to Fossil-Fueled 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 when individual utilities need to address local capacity, flexibility or energy needs 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.

During the last couple of years, some utilities have issued requests for proposals to acquire generating resources. An informal survey identified RFPs calling for over 3,100 megawatts of conventional generating resources, including baseload, intermediate, and peaking resources. It is likely that some of their needs will be met by uncommitted power plants in the region.

For example, in late July 2012, Puget Sound Energy and TransAlta announced 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 were announced, including closure of the 550 megawatt Boardman coal plant in 2020 and closure of one 670 megawatt unit at the Centralia coal plant in 2020 and the other 670 megawatt unit in 2025. These retirements suggest that over the long term, it will be necessary to add resources to replace them, increasing the region's need for new resources.

13. Shifting Regional Power System Constraints

In most other regions of the U.S., power system planning and development tend to focus on making sure that resources will be adequate to meet customer demands during relatively short extreme peak periods such as cold winter or hot summer weather events. In those regions, if resources are adequate to meet peak demands, they are usually sufficient to meet energy needs throughout the year. This is largely because other regions mainly rely on fossil-fueled and nuclear power, whose fuel supplies are relatively abundant and controllable. These systems are described as capacity constrained.

In contrast, the Pacific Northwest power system has traditionally been characterized more as energy-constrained. The main reason for this has been our region's abundance of hydroelectric generation. Unlike other forms of generation that consume fossil or nuclear fuels, the amount of energy the hydro system can produce fluctuates with supplies of water, which in turn depend on uncertain streamflows and limited reservoir capacities. As a result, in the past, the Northwest power system had more than adequate resources to meet peak demands. When constraints occurred, they were usually related to the availability of energy across longer periods of time.

However, during the last decade or so, the Northwest power system has gradually become less energy constrained and more capacity constrained. New resources, partly to meet load growth and partly to meet state-mandated renewable portfolio standards, are driving this shift, and as these new resources have been added, hydro generation's share of the region's total portfolio of resources has gradually declined.

For example, since 2000, 4,758 megawatts of natural gas-fired generation has been added in the region. During that same period, over 7,000 megawatts of wind power has also been built in the region. As utilities must hold more resources in reserve to help balance demand and resources minute to minute, the need for system flexibility has become a new concern.

Persistent low spot market prices for wholesale power are another sign that the Northwest power system has become less energy-constrained. To a degree, low power prices are the result of low prices for natural gas. However, they also reflect direct and ongoing competition between hydro generation and newly-added wind power. Both have very low incremental operating costs and during periods of strong runoff and robust winds, competition between the two can drive spot market prices to very low levels.

While the region is making progress developing a variety of additional mechanisms to integrate wind power, it continues to be a contributing factor affecting the region's needs for peaking capacity and flexibility.

Looking forward, it is apparent that regional power planning needs to take into account shifting constraints on the system. These include reduced constraints for energy and increasing constraints for peaking capacity and for system flexibility.

14. Power and Transmission Planning

Momentum to coordinate power resource and transmission system planning activities has grown in the last few years. Several forces are driving this, including:

- Renewable resources development which, because of their variability, affect power markets and system operations
 - Changes to generation and/or transmission facilities in one area can often cause impacts in other areas
 - Recent major outages that have cascaded across multiple systems, including a widespread event that occurred in the Southwest in September 2011
 - More stringent and comprehensive reliability standards
 - A growing need for new transmission facilities
 - Increasing costs to transmit and integrate renewable and other new generating resources
- In response, various activities and initiatives have been undertaken:
- FERC Order 1000 requiring transmission planning and cost allocation
 - WECC Transmission Expansion Planning Policy Committee
 - Changing roles for WECC (possible division into two organizations)
 - Planning activities of Columbia Grid, Northern Tier Transmission Group, California Independent System Operator
 - Activities to restructure the market and develop new practices (diversifying area control management, investigating energy imbalance markets)

Historically, a major focus for transmission planning was analyzing power flows under peak loading conditions and during contingency events. More recently, attention has broadened to include simulating power flows during various market and operating scenarios. As a result, production simulation models similar to those used for integrated resource planning are also being used for transmission system planning studies. Transmission studies also require assumptions about what new resources will be added by type, quantity, and location.

Past Council power plans have addressed various transmission issues, but intra-regional transmission system constraints and alternative approaches to address such constraints have not been extensively analyzed.

Given the changing situation, regional power and transmission system planning should coordinate by:

- Including the intra-regional transmission constraints and major planned transmission projects in the Council's power system analyses
- Including the Council's power plan assumptions, forecasts, and results in transmission planning studies
- Cross-checking for consistency of major inputs to power and transmission planning studies

The Council has begun working with ColumbiaGrid to identify areas for coordination and will work to improve coordination with other organizations, including WECC, TPPC, and NTTG.

15. Power and Natural Gas System Convergence

During the last decade, natural gas-fired generation has become the leading fossil-fueled resource, both in the Pacific Northwest and nationally. Over 4,700 megawatts of gas-fired generation has been added in the region since 2000. Gas-fired generation is relatively flexible and can be used to supply energy, as well as help balance other resources, including wind power.

As it has become a bigger part of the power system, it has also become a significant source of demand on the natural gas pipeline and storage system. This has raised issues about using the natural gas system for both direct end users and to fuel electric generation:

- Different scheduling and operating practices used by the electric and natural gas industries
- Gas-electric communication and coordination during extreme weather conditions or outage events
- Planning and development of pipeline and underground storage infrastructure
- Access to pipeline and storage facilities for local distribution companies and electric generation
- The impact of rapid swings in use of natural gas for generation to balance variable energy resources like wind power

In response to these issues, several activities have been launched, including the following:

- The Pacific Northwest Utilities Conference Committee and the Northwest Gas Association formed a joint power and natural gas planning task force
- During the summer of 2012, the Federal Energy Regulatory Commission held a series of technical conferences on gas-electric coordination

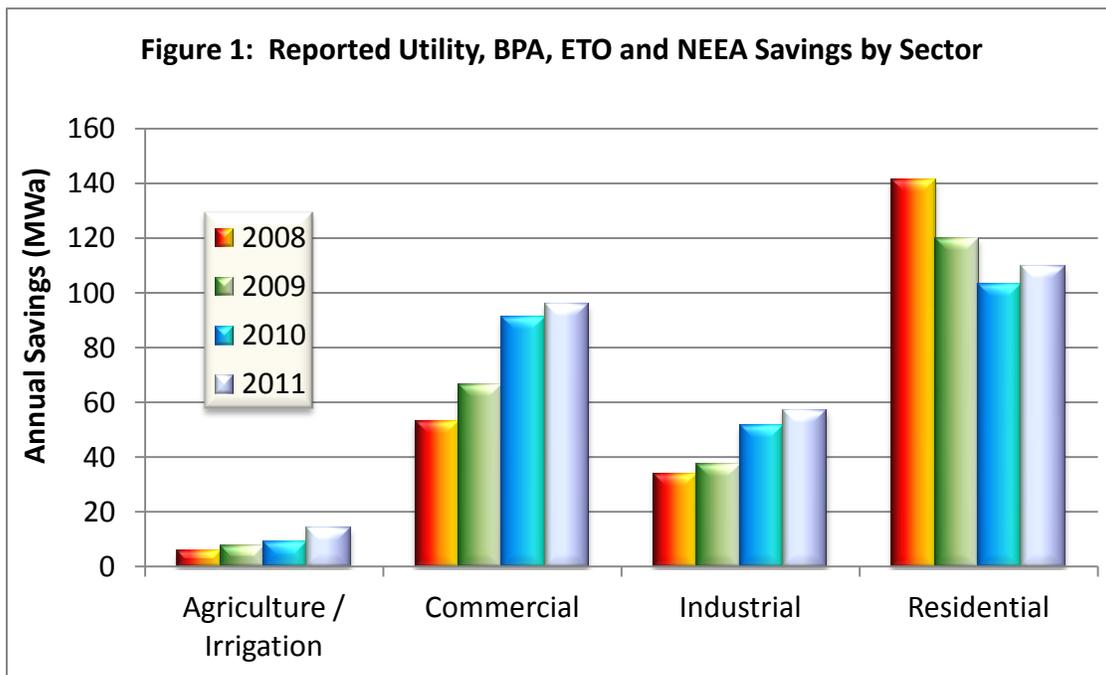
- The Northwest Mutual Assistance Agreement was revamped and expanded to improve utility industry responses to emergency conditions
- A committee of the Western Interstate Energy Board was convened to assess gas-electric issues in the Western U.S., including planning for gas infrastructure

To date, the results of these activities have identified various opportunities to improve communication by the electric and natural gas industries. As natural gas continues to be used to generate electricity, further attention to power and gas convergence will likely be needed.

III. Energy Efficiency Achievements and Issues

Since the Sixth Power Plan was adopted in 2010, the region has acquired over 530 average megawatts of energy savings at an average cost below \$20 per megawatt-hour, well below the cost of new generation fueled by natural gas and long-term wholesale market prices. Through the efforts of the region’s utilities, the Energy Trust of Oregon, the Northwest Energy Efficiency Alliance, and the Bonneville Power Administration,² the plan’s annual energy efficiency targets were surpassed by over 25 percent two years running, with actual accomplishments exceeding targets every year since 2005. Based on utility, ETO, and NEEA projected savings for 2012-2014, it appears that the region should be able to meet the 1,200 average megawatts of savings called for in the Sixth Power Plan by the end of 2014.

The plan identified a range of likely energy efficiency acquisitions during 2010-2014 of between 1,100 and 1,400 average megawatts. Within this range, the plan recommended acquiring 1,200 average megawatts of savings from utility program implementation, market transformation efforts, and codes and standards. Commercial, industrial, and agriculture sector savings have nearly doubled since 2008. Residential sector savings declined in 2008-2010 before increasing again in 2011. The residential-sector decline is due in part to lower savings from residential compact fluorescent bulbs in 2010 and 2011. Figure 1 shows utility and NEEA reported savings by sector since 2008.



² The 530 average megawatts of savings include just fewer than 100 average megawatts achieved through NEEA’s market transformation programs. Not all utilities include NEEA’s savings in their reports. To ensure that all of NEEA’s savings are tabulated but not double counted, all NEEA savings reported by individual utilities are excluded from the regional total. All of NEEA’s 2010 and 2011 savings are then added to this total.

At the suggestion of the Pacific Northwest Utilities Conference Committee, the Council’s Regional Technical Forum surveyed these same entities to assess whether their planned energy efficiency acquisitions for 2012 through 2014 would achieve the remaining savings.

Figure 2 shows the actual and projected savings from 2010 through 2014 for ETO and utilities that responded to the RTF’s survey. These estimates include some, but not all, of the savings from NEEA programs for all years, as well as savings from local utility programs. This figure also shows that these entities serve over 90 percent of the region’s retail load across all years (line on chart).

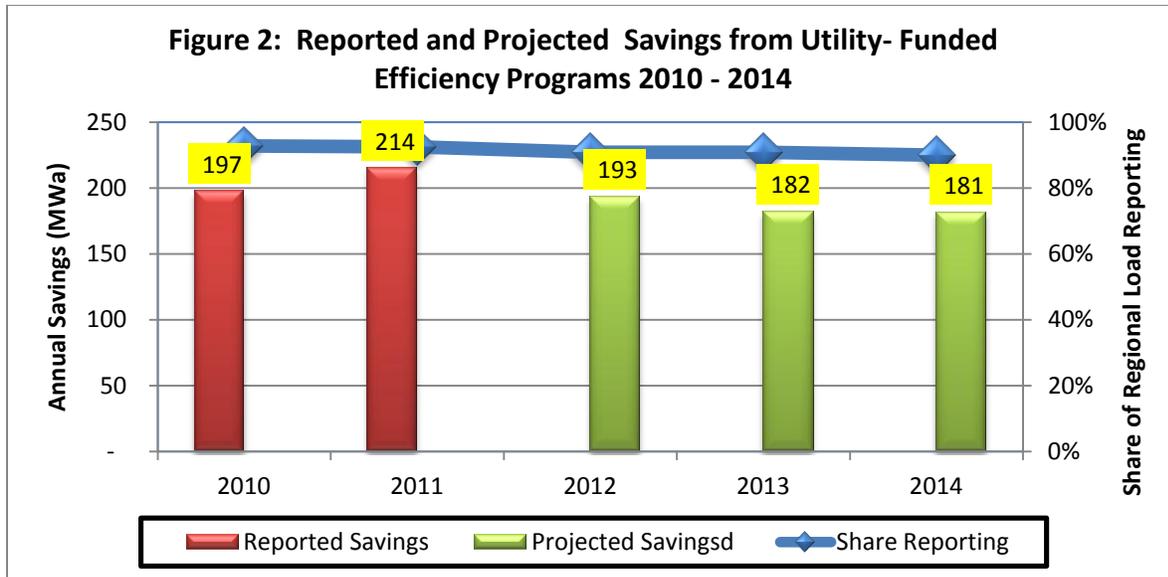
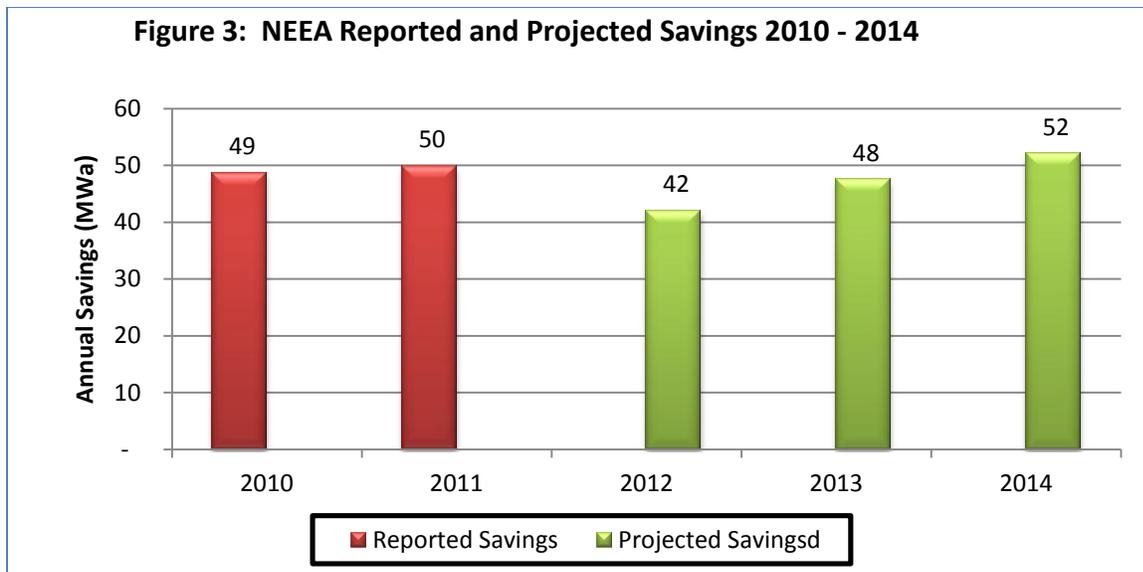


Figure 2 shows that savings from utility and ETO programs are projected to exceed 180 average megawatts each year, totaling approximately 555 average megawatts for the 2012 through 2014 period.

Figure 3 shows the actual and projected savings from NEEA’s regional market transformation activities from 2010 through 2014. NEEA projects that savings from its initiatives will total about 140 average megawatts from 2012 through 2014 for approximately 45 average megawatts each year. The 555 average megawatts from utility and ETO programs, combined with NEEA’s 140 average megawatts, total 695 average megawatts. This, plus the 530 average megawatts already acquired in 2010 and 2011, totals over 1,225 average megawatts by 2014. This is in the middle range of the Sixth Power Plan’s goal.

As well, the Department of Energy has issued final standards for 20 products since 2009, which should produce modest additional savings in 2012-2014, and significant savings thereafter.



Savings outside of utility programs, NEEA, federal standards, and state codes also count toward the Council’s goals. These are typically market-induced savings that are not reported by NEEA or utility programs, such as improvements in commercial lighting. The region does not currently have an estimate of these savings for the five-year period. However, Bonneville is sponsoring a study to estimate these savings, which is expected to be completed near the end of the five-year period.

Although it appears that the region is on track to achieve the Sixth Power Plan’s energy efficiency goal, three factors have been cited as reasons to reduce efficiency investments: low natural gas prices, low wholesale electricity market prices, and slow or no load growth. The primary effect of low natural gas and wholesale electricity market prices is to reduce the amount of efficiency savings that is cost-effective.

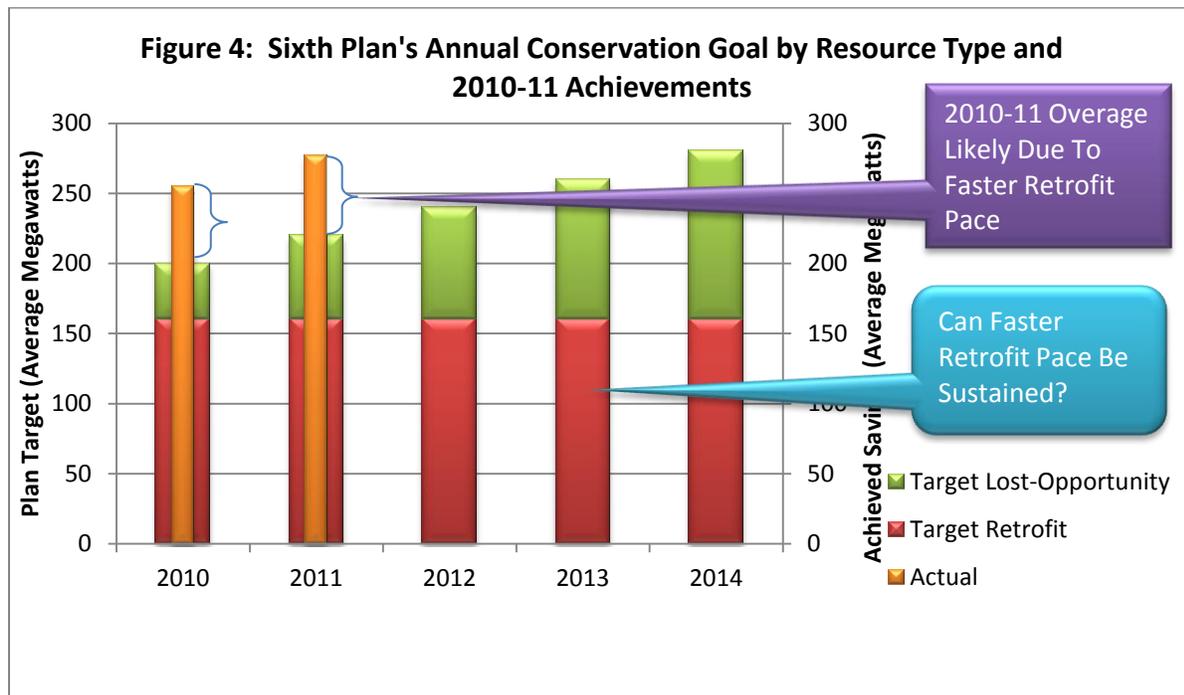
But do these lower prices reduce the amount of cost-effective energy efficiency enough to make it difficult or impossible to achieve the plan’s energy efficiency goal?

To address this question, the Council considered both the pace and cost of the energy efficiency that was achieved over 2010-2011. While past performance doesn’t guarantee future success, evidence suggests that the pace of acquisitions has exceeded the plan’s expectations while the costs have been consistent with the plan’s expectations.³

³ The Sixth Power Plan assumed that approximately two-thirds of the total cost of utility acquired energy efficiency would be recovered in revenue requirements and the remainder paid for by program participants. This levelized cost average was \$23 per megawatt hour over the initial years of the planning period. See Appendix O: Calculation of Revenue Requirements and Customer Bills, p.3.

http://www.nwcouncil.org/energy/powerplan/6/final/SixthPowerPlan_Appendix_O.pdf

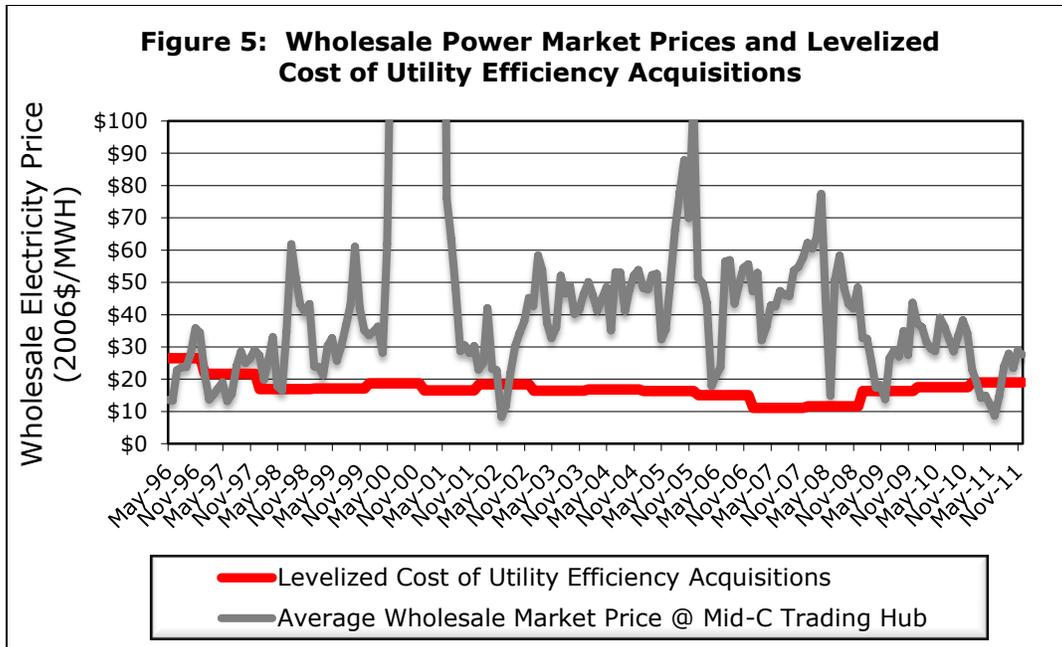
Figure 4 shows that the plan’s annual energy efficiency goal was split between retrofit and lost-opportunity resources in the first two years of the planning period. It also shows that the pace of retrofit acquisitions has likely exceeded the plan’s assumed maximum pace of 160 average megawatts annually. Even though the slow economic recovery limited lost-opportunity resources from new buildings and appliances, the region still exceeded the plan’s targeted pace by capturing more retrofit energy efficiency than expected. And it did so at very low cost.



The estimated levelized cost of energy efficiency was \$18 per megawatt-hour.⁴ This low average cost was achieved with programs targeting efficiency with a much higher total levelized cost; up to \$70 to \$100 per megawatt-hour. Two factors keep costs low. First, utilities are only paying part of the cost, with customers picking up the remainder. Second, even though some measures are relatively high cost, the bulk of the savings come from low-cost measures. This cost of energy efficiency is at or below recent low wholesale prices of electricity, and well below historical market prices.

Figure 5 shows the 1996-2011 prices of wholesale electricity and the levelized cost of energy efficiency for utilities. Monthly market prices are not equal to the levelized cost of energy savings. However, monthly market prices are one proxy for the short-term cost of buying power instead of building efficiency, as well as the value of selling surplus efficiency in the short-term market. The chart also illustrates the volatility of short-term market prices and the relative stability of the utility cost of energy efficiency.

⁴ The levelized cost of \$18 per megawatt-hour is based on a 13-year measure life and a 5 percent real discount rate in 2006\$.



Energy efficiency acquired at this accelerated pace over the last two years is also below most forecasts of future market prices, and well below the cost of new generating resources. Figure 6 shows the estimated levelized cost of a new combined-cycle combustion turbine fueled with natural gas (at prices of \$2, \$4, and \$6 per million Btu) and dispatched at three different capacity factors: minimum (17%), average (51%), and maximum (79%). The graph shows that fueled by \$2 per million Btu gas under the average dispatch rate, it produces energy at a levelized cost of about \$50 per megawatt-hour. Under the maximum dispatch rate, the levelized cost drops to approximately \$40 per megawatt-hour. Figure 6 also shows that the historical average levelized cost of energy efficiency savings has been \$18 per megawatt-hour, substantially below the cost of a new CCCT.

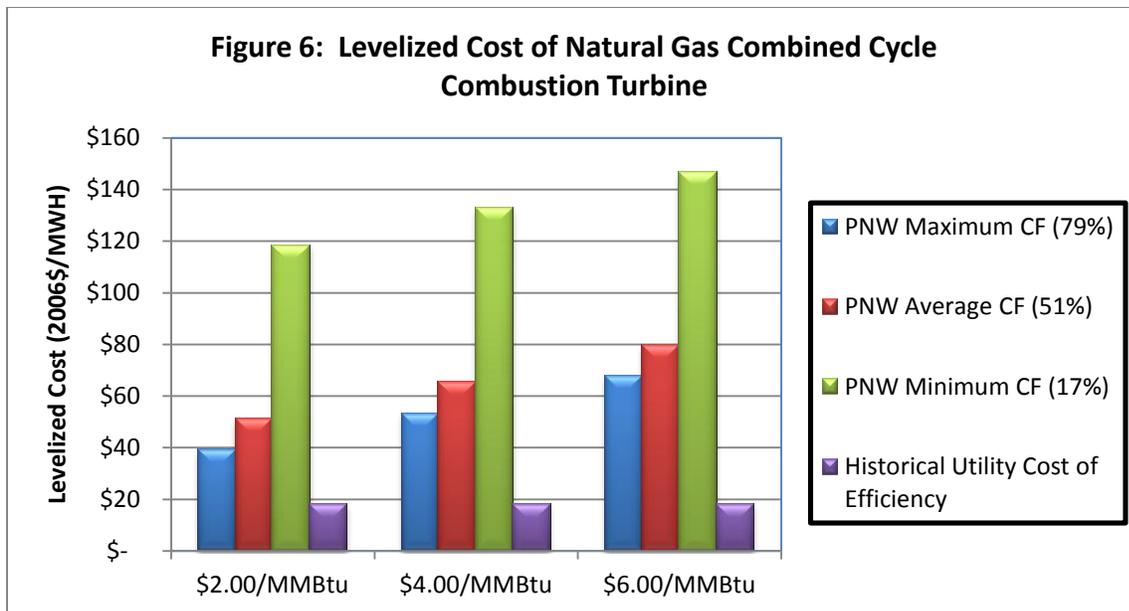
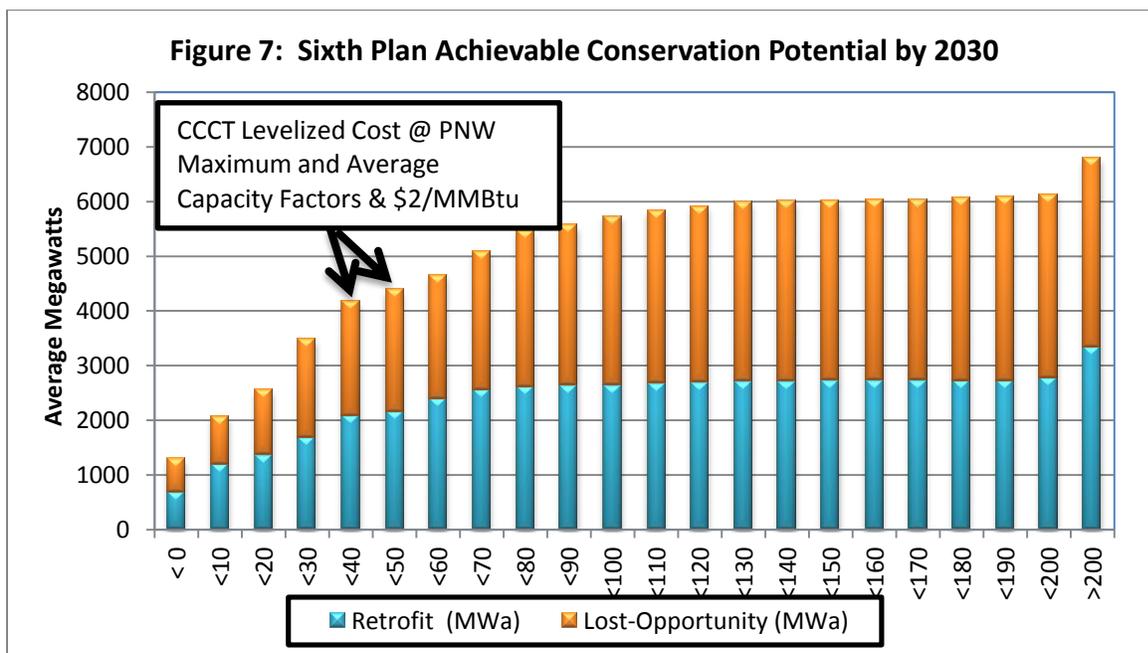


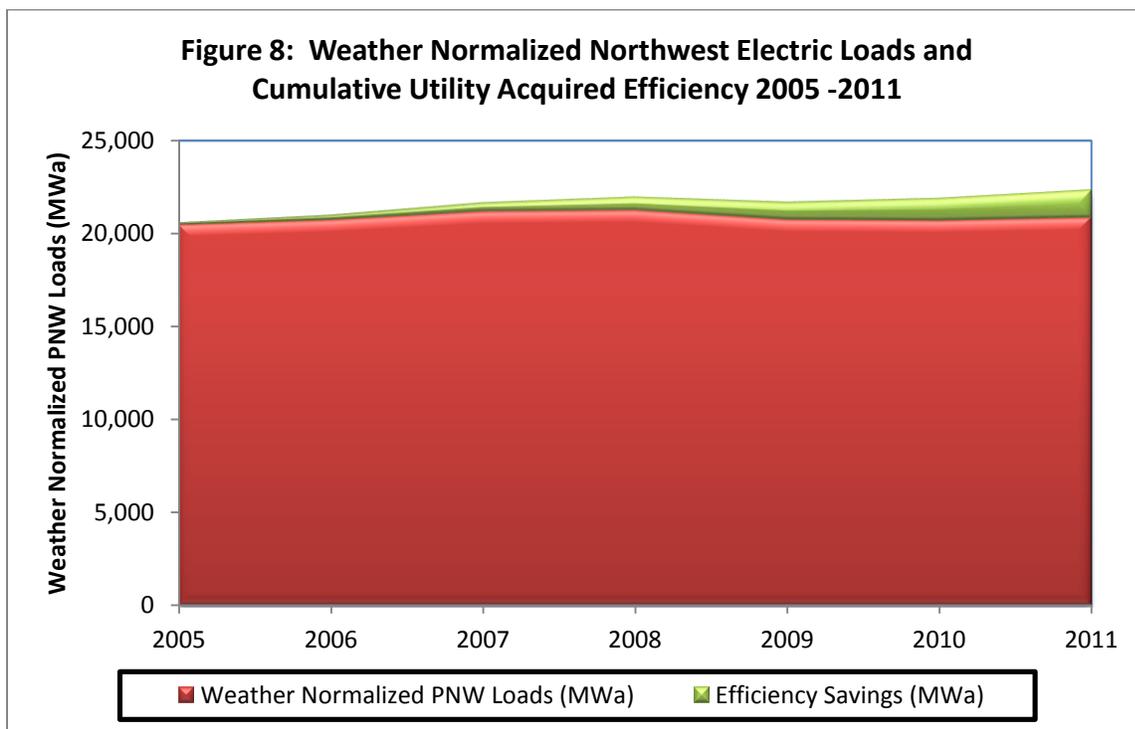
Figure 7 shows there are over 4,000 average megawatts of cost-effective efficiency potential below \$40 per megawatt-hour, the levelized cost of a CCCT dispatched at an 80 percent capacity factor and fueled with \$2 million Btu natural gas. Moreover, this potential is about evenly divided between lost-opportunity measures and retrofit measures. This means that even if the economic downturn persists, there is still ample cost-effective energy efficiency resource potential to meet the plan’s goal at costs below a new CCCT through untapped retrofit opportunities.



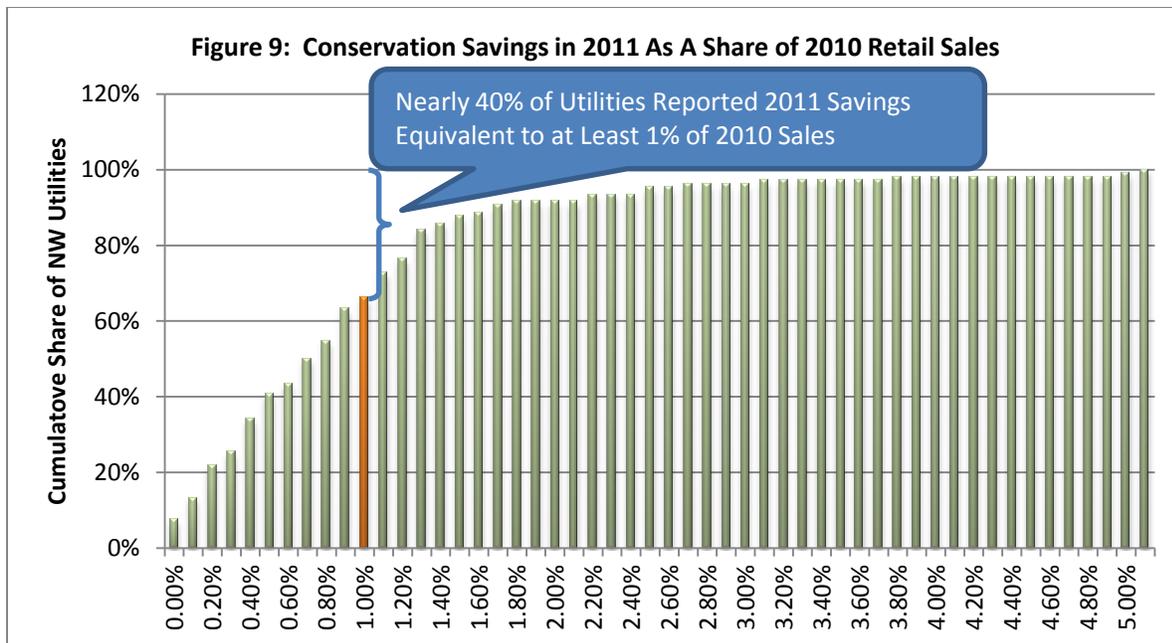
The third concern raised during the Council’s Mid-Term Assessment regarding continued aggressive energy efficiency acquisition is that some utilities have been experiencing slow or no

load growth. It's clear that the recession has reduced electricity demand. However, it's also true that energy efficiency acquired since 2005 has reduced load growth as well. The 277 average megawatts of utility acquired energy efficiency in 2011 was equivalent to 1.3 percent of 2010 loads adjusted for weather. This means that regional electricity loads would have had to grow by more than 277 average megawatts, or 1.3 percent, to produce net year-over-year growth.

Figure 8 plots the weather adjusted loads from 2005 through 2011, along with the cumulative energy efficiency savings acquired by utilities, ETO, NEEA, and Bonneville over this same period. It shows that loads, after peaking in 2008, have since fallen, and in 2011 were approximately the same as in 2005. While the economic downturn certainly contributed to lower regional electricity use, the nearly 1,500 average megawatts of energy efficiency also significantly dampened growth.



Across the region, the impact of energy efficiency on individual utility retail sales varied considerably. Figure 9 is a histogram that plots the cumulative share of utility savings in 2011 as a percent of their 2010 retail sales. As this graph shows, nearly 40 percent of the utilities in the region reported energy savings in 2011 equivalent to at least 1 percent of their 2010 retail sales. On the other hand, another 40 percent reported 2011 savings equivalent to less than 0.5 percent of their 2010 retail sales. At either end, a utility may be experiencing little if any growth in retail sales if its efficiency savings offset a substantial portion of that growth.



Future Energy Efficiency

The region continues to diversify its energy efficiency portfolio, as illustrated in the growing savings from the commercial and industrial sectors and lower residential lighting savings. Due to economic conditions, the region has also focused on retrofit savings to compensate for diminished opportunities in new construction and appliance and equipment replacements. Despite these shifts, the costs to acquire efficiency have remained very low. Progress made on federal appliance efficiency standards and state building codes will significantly reduce future load growth. As a result, continued focus on emerging technologies will be increasingly important.

Since the Council's Fifth Power Plan in 2005, cumulative savings are nearly 1,500 average megawatts, which appear to be significantly dampening regional load growth, and for some utilities may be completely offsetting load growth. This in turn reduces the need for new generation and transmission, and may also spur changes in the way utilities are operated and regulated since return on investment has historically been a key factor in utility economic performance.

As the region faces an increasing need for capacity and flexibility, identifying how energy-efficiency programs affect the system will become more important. Data on the hourly, daily, and seasonal patterns of electricity use are over 20 years old. Appliance saturations, improved equipment efficiency, and changing behavior may have significantly altered these patterns. The evolution of the Internet, electronic devices, and electric vehicles continue to change how we communicate and do business. Improved end-use research is needed to understand how these profound changes in electricity use are influencing capacity and flexibility requirements.

IV. Renewable Resources

A. Introduction

Electricity generation based on renewable energy has grown rapidly in the Pacific Northwest, driven by changing technology and state and federal policies. This growth has presented challenges to the regional power system, primarily in the form of increased requirements for balancing reserves and oversupply episodes during the runoff of the winter snowpack.

Which renewables?

While the existing hydro system is clearly a renewable resource, the issues in this assessment have to do with new generation that qualifies as renewable generation for Washington, Oregon, and Montana renewable portfolio standards and for federal production and investment tax credits and investment grants.

B. Historical development 2000 to Present

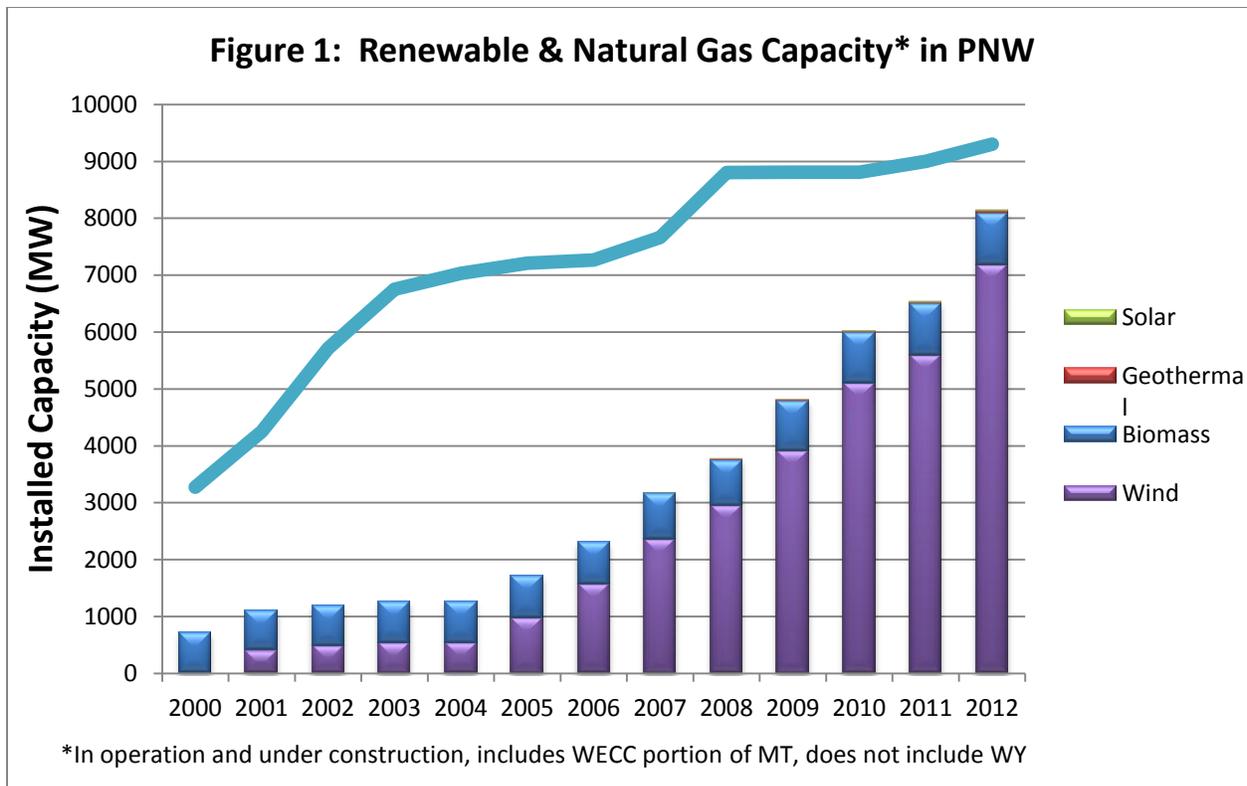
A number of state and federal policies have stimulated the development of renewable generation in the region. The Washington renewable portfolio standard requires utilities with more than 25,000 customers to obtain at least 15 percent of their energy requirements from renewable sources by 2020. Oregon requires that the renewable share be 25 percent by 2025 for large utilities (5 percent - 10 percent for smaller utilities). Montana requires that 15 percent of load be met by renewable by 2015. Idaho has not adopted renewable portfolio standards, but is experiencing significant wind development as the result of federal tax incentives and PURPA requirements.⁵ California has adopted increasingly ambitious renewable portfolio standards, the latest of which requires 33 percent by 2020. A portion of California's requirements are currently being satisfied by plants located in the Pacific Northwest, but a recent change in policy issued by the California Public Utilities Commission restricts the amount of tradable renewable energy credits (TRECS) used for RPS compliance. As a result, California is shifting to more in-state wind and solar resources rather than importing additional resources from the Northwest. The federal government has offered production and investment tax credits⁶ and investment grants for qualifying renewable generation. Currently, the federal wind production tax credit is expected to expire at the end of 2012, unless extended by Congress.

The result of these state and federal policies has been that new renewable generation has been built at a rapid pace in our region. Figure 1 shows the total amount of new renewable generation operating or under construction in the years since 2000, and for perspective also shows the natural gas generation capacity in the same years. Of the 8,146 MW total by late 2012, 17 MW is solar, 908 MW is biomass, 38 MW is geothermal, and 7,183 MW is wind. Of the 7,183 MW of wind, about 3,000 MW, or about 42 percent is committed to serve load outside the Northwest.

⁵ The governor of Idaho has issued executive orders calling for the encouragement of renewable energy development, including "Promoting cost effective energy conservation and utilization of renewable energy resources through public information, education, and other activities"

http://gov.idaho.gov/mediacenter/execorders/eo11/eo_2011_14.html (5-3)

⁶ See Table I-2 in Appendix I of the Council's Sixth Power Plan at http://www.nwcouncil.org/energy/powerplan/6/final/SixthPowerPlan_Appendix_I.pdf



C. Integration Challenges

These increases in renewable electricity generation have posed a number of challenges to the Pacific Northwest’s power system. Individual utilities face local problems to their distribution systems and operations due to solar and biomass generation. However, since wind is the prevalent form of renewable energy being added to the system, the regional-scale challenges are generally due to the characteristics of wind generation and are concentrated in Bonneville’s control area.

1. Integration Challenges - Transmission System

The areas of high quality wind resources are not close to load centers, so the location and capability of the transmission system is crucial. So far, wind projects have been constructed in areas where the cost of connecting the projects to the transmission system has been modest. Expansion of wind energy production into areas that will require significant expansion and extension of the transmission system will be more expensive, but it appears that for the next few years incremental improvements to the transmission will suffice.

2. Integration Challenges - Operating Reserves

The variability of wind, added to the variability of demand for electricity, has increased the power system’s need for operating reserves. Thanks in large part to our region’s hydroelectric system, our region has been able to meet these operational reserve needs so far, but there is

concern that we may be approaching the system's limits.

This challenge could be met by actions that reduce the need for operating reserves, or finding new and/or cheaper sources of operating reserves, or a combination of the two. The need for operating reserves might be reduced by increasing the frequency of scheduling and dispatch of generation (e.g. moving from hourly scheduling and dispatch to 30-minute scheduling and dispatch); dynamic transfers (sharing responsibility for operating reserves between control areas); an energy imbalance market that covers several control areas; improved wind and weather forecasting; and consolidating control areas. Bonneville has implemented 30-minute scheduling and offered discounted wind integration charges to customers who commit to 30-minute scheduling. Each of the other possibilities for reducing the need for operating reserves is under consideration by regional groups.

New and/or cheaper sources of operating reserves might include using controllable loads (demand response) that can increase or decrease on short notice as called upon by the power system. Bonneville has commissioned a pilot project testing this concept with electric water heaters and refrigerated warehouses, which has recently been completed with encouraging results. Bonneville, in cooperation with the municipal utility of the City of Port Angeles, is also testing the ability of a pulp and paper plant to provide operating reserves. Most recently, Bonneville is initiating a study of data centers as potential sources of operating reserves. Other possible sources of new operating reserves include the use of the pumped storage potential of the Keys pumping/generating station at Grand Coulee Dam, and the construction of new peaking generation such as natural gas-fired simple cycle turbines.

3. Integration Challenges - Oversupply Episodes

While the essentially zero variable cost of wind generation means that under normal circumstances the power system should accept all the electricity produced by wind, there are circumstances (low loads, high runoff in the hydro system, and high wind) that can produce more electricity than can be used over periods of hours. Oversupply episodes occurred on occasion in the Pacific Northwest even before significant wind generation on the system, and they can occur even in power systems where there are no hydro and no wind resources, but 2011 and 2012 Bonneville saw combinations of high generation and low loads that resulted in curtailment of about 97,000 MWh and 47,000 MWh, respectively, of wind energy. The amount of curtailment depends on the amount and timing of wind, snowpack runoff, and load, but Bonneville has estimated that the expected cost of curtailed wind at our current level of demand and wind generation capability is about \$12 million per year. More importantly, there is the possibility of considerably higher costs in extreme years.

These episodes occur during the spring runoff of the region's snowpack, during light load hours (10 p.m. to 6 a.m.). During spring, there are minimum flow requirements on the river to accommodate the runoff without flooding, and there are limits on the amount of total dissolved gases in the water to protect young salmon that are migrating to the ocean. Running water through generator turbines creates less dissolved gases than spilling water past the dams without generating. The minimum flow requirements result in minimum generation by the hydro system in a season when loads are relatively low. During the night, when loads are especially low and the wind is blowing, episodes when the combination of minimum hydro generation, wind, and

thermal generation with limited flexibility to reduce output⁷, amounts to more generation than can be absorbed by demand. In such circumstances, the choices are to pay customers to accept electricity (i.e. accept negative prices) or curtail some generators involuntarily. Bonneville's policy is to curtail if necessary, with a sharing of the cost of that curtailment.⁸

Coordinated by the Council, Bonneville and other regional groups have put considerable effort into understanding oversupply episodes and exploring measures that could reduce the frequency and magnitude of these episodes.⁹ The Wind Integration Forum's Oversupply Technical Oversight Committee looked at a number of possibilities to mitigate oversupply episodes, ranging from reducing total dissolved gases by spilling water at different dams or passing water through navigation locks, to installing resistive load banks to absorb excess electricity by converting it to heat, to market mechanisms to encourage (or at least not discourage) shifting load into light load hours. Some of the measures examined overlap with measures under consideration for operational reserves, such as dynamic transfers and an energy imbalance market across control areas.¹⁰

The committee concluded that while there is no single, quick and cheap measure to eliminate oversupply episodes, there are a number of measures that together could significantly mitigate their frequency and severity. Many of these measures could have other benefits as well.

4. Projections for Future Renewable Generation

Currently, regional utilities seem to have adequate renewable generation to cover their RPS requirements until about 2016, and new construction has slowed considerably. However, they have not yet reached the final RPS levels and will need to resume eventually. Utilities have proposed projects to meet these levels, but it is hard to predict the future pace of acquisition of renewable generation. Utilities can satisfy their requirements by building generation, acquiring renewable energy certificates from generation owned by others, by using those they have banked from years when they had a surplus, or by a combination of these actions. A rough estimate of ultimate RPS requirements for Washington, Oregon, and Montana would be about 8,000 to 9,000 MW of capacity by 2025 if the requirement is satisfied by wind. Assuming that the 3,000 MW committed to loads outside the region remains constant through 2025, another 3,000 to 4,000 MW may ultimately be needed to meet the region's RPS.

Though these numbers are approximate, they do indicate that there will be a significant amount of further acquisition of renewable generation before the states' renewable portfolio standards are fully satisfied. The region is likely to be dealing with the challenges of integrating renewable generation for some time to come.

⁷ For example, the Columbia Generating Station nuclear plant.

⁸ This policy is being litigated in front of the Federal Energy Regulatory Commission (FERC).

⁹ See the Council's web page for the Wind Integration Forum, at <http://www.nwcouncil.org/energy/Wind/Default.asp> on the work of the Oversupply Technical Oversight Committee (OTOC), and Bonneville's web page on oversupply, at <http://www.bpa.gov/Projects/Initiatives/Oversupply/Pages/default.aspx>

¹⁰ See <http://www.nwcouncil.org/energy/Wind/otoc/default.asp> for details.

V. Natural Gas-Fired Generating Resources

Natural gas-fired generation constitutes about 16 percent of Northwest¹¹ capacity and about 39 percent of overall generating capacity in the Western Electricity Coordinating Council region. Efficient, reliable, low-emission natural gas-fired combined-cycle plants have been the new resource of choice for two decades in the WECC for intermediate and continuous duty electricity generation. Eighty-seven percent of thermal base load capacity constructed in the WECC since 1990 has been natural gas-fired combined-cycle plants. Other gas-fired capacity in the WECC includes single-cycle gas turbines and reciprocating engine plants used for peaking and balancing¹² reserves and cogeneration plants. Older steam units, originally constructed for continuous and intermediate load duty are now largely used for meeting peak loads and local grid support.

Recent Construction of Natural Gas-Fired Generation in the Northwest

Three utility-scale natural gas-fired plants providing 498 MW of capacity have come on line in the Northwest since 2009 (Table 1). Langley Gulch is a large combined-cycle plant intended to help meet Idaho Power's increasing summer peak loads and reduce dependence on purchased power. Construction of Langley Gulch has extended a fairly continuous expansion of combined-cycle capacity in the Northwest since the 2000-01 energy crisis (Figure 2). Highwood and Dave Gates (ex-Mill Creek) are single-cycle gas turbines providing peaking and balancing reserves. The Dave Gates station helps meet the need for balancing services to support ongoing wind development in Montana.

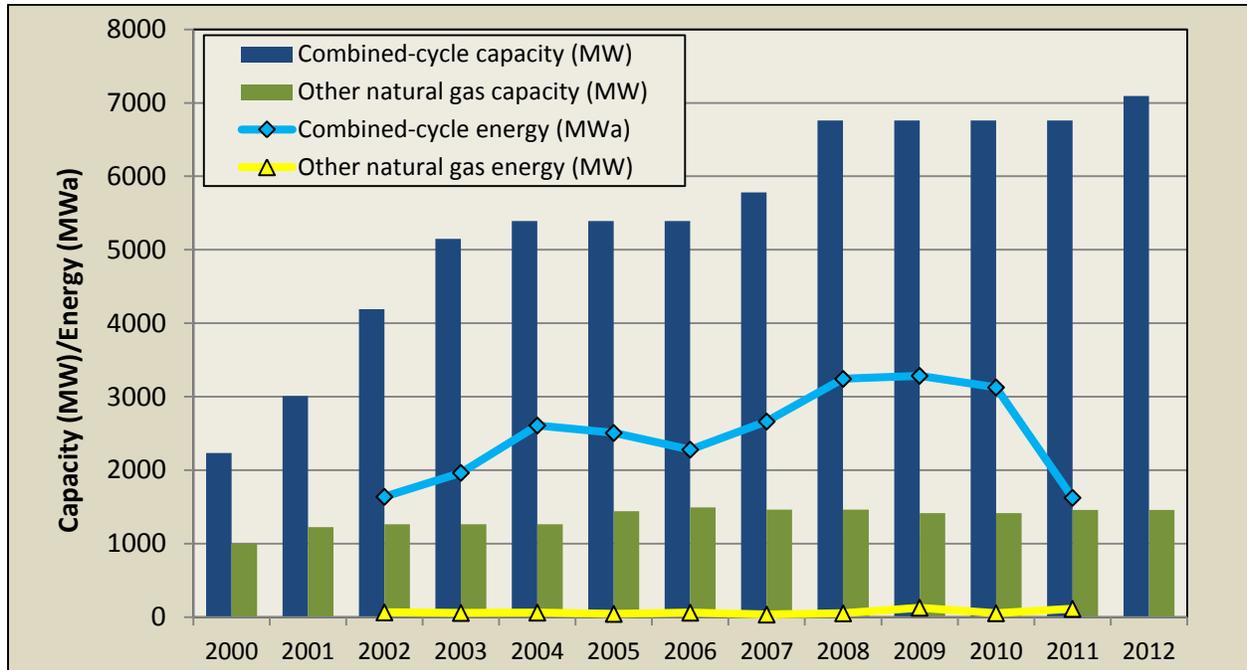
Table 1: Northwest natural gas plants placed in service from 2009 through 2012

Plant	Owner	Location	Service	Capacity (MW)	Technology
Dave Gates	NorthWestern	Anaconda, MT	Jan 2011	150	(3) Pratt & Whitney SWIFTPAC 50 gas turbines
Highwood	Southern MT G&T	Salem, MT	Sep 2011	43	(1) LM6000 gas turbine
Langley Gulch	Idaho Power	New Plymouth, ID	Jun 2012	300	1x1 Siemens SCT6-5000 combined-cycle

¹¹ Idaho, Montana (WECC portion), Oregon and Washington.

¹² Balancing the net of load variation and the variable output of wind and solar generation.

Figure 2: Cumulative Northwest natural gas capacity and annual energy production since 2000



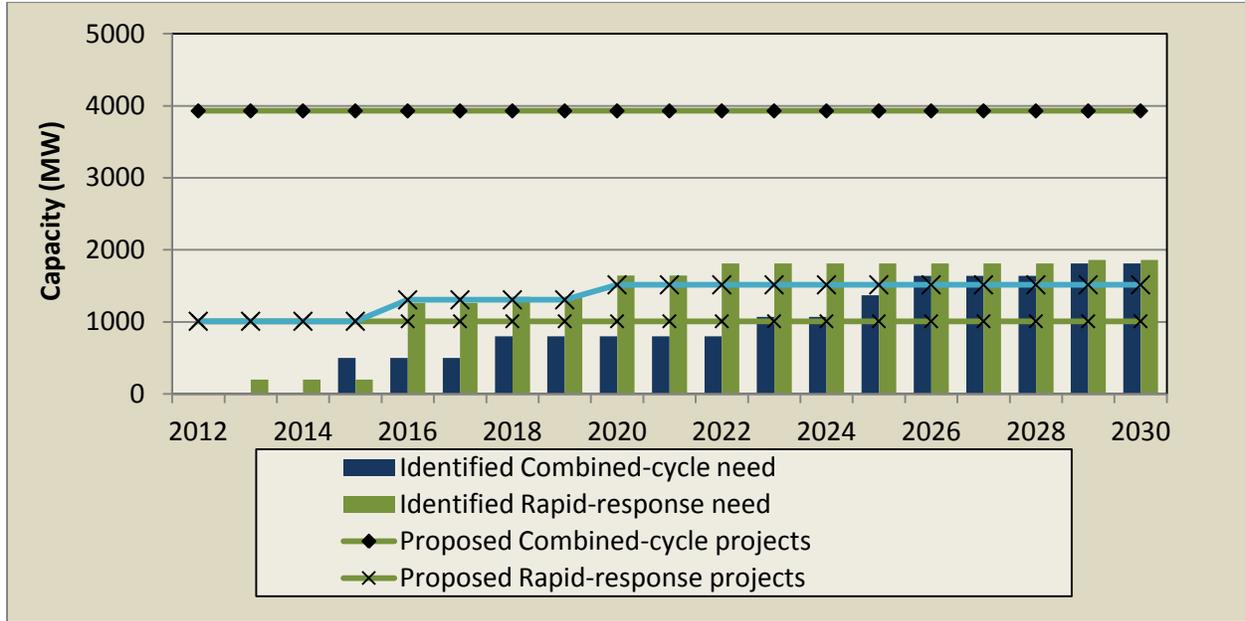
Natural gas generation represents about 10 percent of Northwest capacity added during 2009 - 2012 (the majority, 86 percent, being wind). Natural gas-fired power plants now constitute 15 percent of installed generating capacity (9,570 MW) in the interconnected four-state area.

Proposed Natural Gas-Fired Generation Projects

No natural gas-fired capacity is currently under construction in the Northwest. Several proposed plants have been permitted, or are in the permitting process. Four combined-cycle plants totaling 2,750 MW and one rapid response plant (gas turbine or reciprocating engine) of 200 MW hold site certificates. Three additional combined-cycle plants totaling 1,180 MW and three rapid response plants totaling 810 MW are known to be in the permitting process. These proposed sites are all in Oregon or Washington. Additional projects have been announced, but currently do not appear to be active.

Utility Plans for Acquiring New Natural Gas-Fired Generation

Figure 2: Forecast need for new combined-cycle and rapid-response capacity vs. proposed projects



Additional gas-fired generating capacity will likely be required to replace a portion of planned coal plant retirements. In addition, some of the Centralia capacity may need to be replaced with gas-fired capacity to provide voltage support along the I-5 transmission corridor. The Centralia plant site with gas, transmission, and cooling infrastructure, and an existing gas combined-cycle plant (Big Hanaford) would be an attractive site for replacement gas-fired facilities.

Technical Developments

Increasing demand for economical sources of balancing reserves to integrate large amounts of variable wind and solar generation has made improving the operational flexibility of natural gas generating technology a new priority.

In the Northwest, peaking and balancing services have traditionally been provided by hydropower. In areas with limited hydropower, a combination of pumped-storage hydropower, single-cycle gas turbines, and aging gas steam units meet these needs. Generating equipment vendors have developed equipment with greater operating flexibility that are being implemented. One example of this is mid-sized intercooled single-cycle combustion turbines. These units combine operational flexibility with improved fuel efficiency. To meet local needs, reciprocating engines provide fast start capability and operating responsiveness.

Cost Trends

Declining natural gas prices have reduced the operating costs of gas-fired generation making it more competitive with other generating resources. This has made gas-fired generation more cost-effective to help integrate renewable resources like wind. However, even combined-cycle plants typically operate at fairly low capacity factors, ranging from a low of 24 percent in 2011 to a high of 49 percent in 2009.

VI. Resource Adequacy

The region's current adequacy standard limits the likelihood of a power supply shortfall five years into the future to a maximum of 5 percent. The assessment only counts existing resources (and those that are sited and licensed) and the targeted amount of energy efficiency savings as outlined in the Council's power plan.

The last official adequacy assessment, published in the Council's Sixth Power Plan, indicated that the regional power supply would remain adequate through 2015. The expected likelihood of a shortfall (or loss of load probability), however, was right at the Council's limit of 5 percent, which meant that the supply was on the cusp of becoming inadequate. The critical month was August when the gap between supply and demand was anticipated to continue to grow smaller unless new resources were developed.

The current assessment (for 2017) shows the expected loss of load probability to be 6.6 percent, indicating that the regional power supply will be inadequate unless additional resources are acquired. This is the first time an impending shortfall has been identified. The assessment also concluded, however, that it would only take 350 megawatts of new dispatchable generation capacity to bring the loss of load probability back down to 5 percent. The report also indicated that an annual average decrease in demand of 300 average megawatts in 2017 would bring the LOLP back down to the 5 percent limit. The report cautioned, however, that it is possible the amount of new resources needed to maintain adequacy could differ depending on how Northwest economic growth develops and how the Southwest market availability changes.

These findings are consistent with assessments made by regional utilities that indicate they need new resources. It is also consistent with the power plan, which concluded that energy efficiency alone will not be sufficient to offset all future load growth. In aggregate, utility planned resources far exceed the 350 megawatt gap.

In the analysis for 2017, the most critical months are January and February and, to a lesser degree, August. This is a different result from the last official assessment, which indicated that August was the most critical month. The major reason for this shift is the use of an updated streamflow record, which contains 10 more years of historical flows, new irrigation withdrawal amounts and various updates to reservoir operations both in the U.S. and Canada. The net result yields a higher average streamflow in August, thus improving summer adequacy.

Types of potential problems the region could face range from energy shortfalls that could last for several days to peak curtailments that last several hours or longer. Results show that the majority of simulated shortfalls (52 percent) are 4 hours or less in duration and over 40 percent are 2 hours or less. Only 15 percent are longer than a day and 35 percent last longer than 8 hours.

To minimize cost and risk, new resource additions should be tailored to specifically address the expected types of shortfalls, that is, peak-hour shortages. This suggests that capacity resources such as simple-cycle combustion turbines or demand response programs or winter-peaking energy efficiency measures that produce savings during peak periods should be considered. It should be noted again, however, that the scope of this assessment is only to provide a gauge of the relative adequacy of the power supply. The determination of the quantity and mix of new

resource capacity needed make the power supply adequate is left to more comprehensive integrated resource planning processes.

A. Load and Resource Data Updates

Since the assessment in the Sixth Power Plan for 2015 to the current assessment for 2017, there have been changes in projected loads and resources. Between 2015 and 2017, the region's electricity loads, net of planned energy efficiency savings, are expected to grow by about 300 average megawatts or about a 0.7 percent annual rate. Since the last assessment, 114 megawatts of new thermal capacity and about 1,200 megawatts of new wind capacity have been added along with about 250 megawatts of small hydro and hydro upgrades. The recent acquisition of 380 megawatts of a regional independent power resource has been included and the in-region market supply has correspondingly decreased.

California is expected to retire a substantial amount of its coastal water-cooled thermal power plants. It is also uncertain whether two units at the San Onofre Nuclear Generating Station will be operational in 2017. As a result, the forum reduced its assumption for the availability of California winter on-peak market supply from 3,200 to 1,700 megawatts.

1. Action Items in the Sixth Plan Pertaining to Resource Adequacy

The Council's Sixth Power Plan identified four action items related to resource adequacy:

- Assess the adequacy of the region's power supply annually.
- Update and review load and resource data annually.
- Periodically review the methodology used to assess adequacy.
- Work with entities in other regions to share methodologies and assessments.

The Council has set up a procedure, through the Resource Adequacy Forum, to assess the adequacy of the power supply annually. Part of that process includes updating resource and load data on an annual basis. The Council has also conducted a peer review of the methodology and subsequently amended its adequacy standard.

VII. Updates to Key Forecasts

During the development of the mid-term assessment, the Council heard from regional stakeholders that its forecasts, updated for the assessment, are relevant and useful. In the future, the Council intends to release its key forecasts on an annual basis.

A. Regional Demographics and Economics

Population stable, economy expanding, new homes being added, commercial sector recovery may take longer, new small and large loads being added in the region.

Population: The regional population has been stable in 2010-2011 but looking forward to 2030, the forecast for population shows an increase of about 300,000 compared to the Sixth Power Plan's forecast, which will mean an increase in demand for new homes and goods and services.

Economy: During development of the plan, we had expected a more fully recovered regional and national economy by 2010. The expected growth did not materialize, and the region lost about 184,000 jobs compared to 2008. Recent economic news indicates that although in terms of employment and job creation, the recovery has been sluggish, in terms of demand for electricity, there has been a stronger recovery.

The regional economy's growth has been moderate. During 2010 and 2011, the value of goods and services produced in Oregon, Washington, Idaho, and Montana increased from about \$545 billion 2005 dollars to about \$581 billion 2005 dollars, a net increase of \$36 billion dollars. Economic growth has not been uniform across all sectors. For 2007-2011, the regional economy grew at a moderate rate of 1.3 percent per year. Growth sectors included durable manufacturing, information technology industries, health care, and technical services. Declining sectors included construction, mining, transportation, wholesale trade, and government services. This reflects a trend of the past 10 years.

The economic drivers that more directly affect regional demand include the stock of residential and commercial buildings, as well as industrial output. While industrial output has increased in the past few years, the construction sector has declined. This sector produced about \$27 billion dollars of value in 2007, but declined to about \$20 billion dollars by 2011. The slowdown in construction is evident in the lower number of new homes and cutbacks and delays in commercial construction.

Long term, the expectations are that the number of new homes will increase and new residential construction will shift more toward multi-family rental homes rather than single-family detached units.

Residential new home construction activities: In the Sixth Power Plan, we had anticipated that an additional 128,000 single family homes would be added during 2010 and 2011 period. However, the actual additions were about 102,000 units. Lower than expected additions were also seen in multi-family units, where the plan's forecast was for about 28,000 unit additions but

the actual turned out to be about 23,000 units. Recent indications are for an increase in construction activities and shrinking inventory of single-family homes.

Commercial new construction activities: The expectations were that during 2009-2011, about 134 million square feet would be added; the actual new additions were closer to half that amount, around 70 million square feet. As the employment picture improves and demand for new commercial floor space increases, we expect to see an increase in construction activities and the overall commercial building stock is expected to be higher in 2030.

The long-term projections for employment also results in lower floor space requirements and lower new floor space additions. For 2010-2030, we had anticipated an overall floor space addition of about 896 million square feet, but the new forecast expects about 843 million square feet. This translates to about 53 million square feet less or a 6 percent reduction in new floor space.

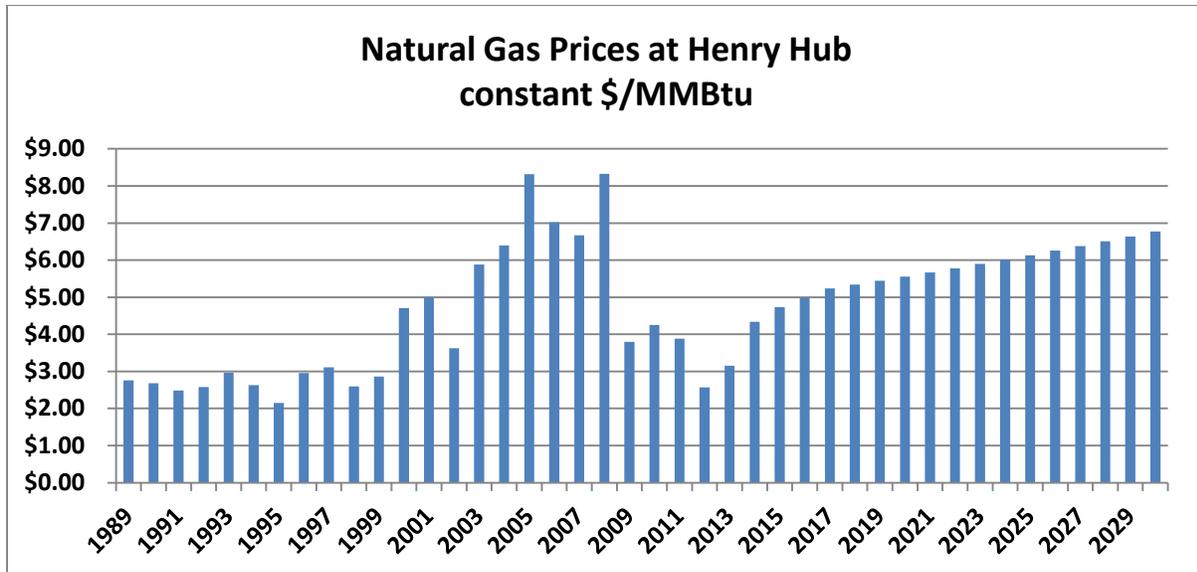
New large single loads: One of the newly growing segments of demand has been data centers. Custom and mid-tier data centers have been attracted to the Northwest because of financial incentives, low electricity prices, and an available pool of skilled professionals. A number of large data centers have been built in the region in the last few years, and we have revised our load forecasts to include these new sources of demand.

Another entry to the electricity demand market has been plug-in electric vehicles. Although this market segment is currently very small, should the technology, customer acceptance, and availability of vehicle charging stations continue at its current pace, it could increase regional demand for electricity.

B. Natural Gas Prices

Although natural gas prices have been depressed in the past few years, they are not as low as they have been historically. Natural gas wellhead prices dropped significantly from about \$7.75 per MMBtu in 2008 to an average of about \$3.40 per MMBtu in 2010-2012. Although this drop is significant, after adjusting for inflation, 2010-2012 average prices were 30 percent higher than prices during 1989-1999.

Because the price of natural gas is a key factor influencing electricity prices and demand, the Council monitors this market continuously. In the past two years, the Council has made two downward revisions to its long and short-term forecasts of natural gas prices.

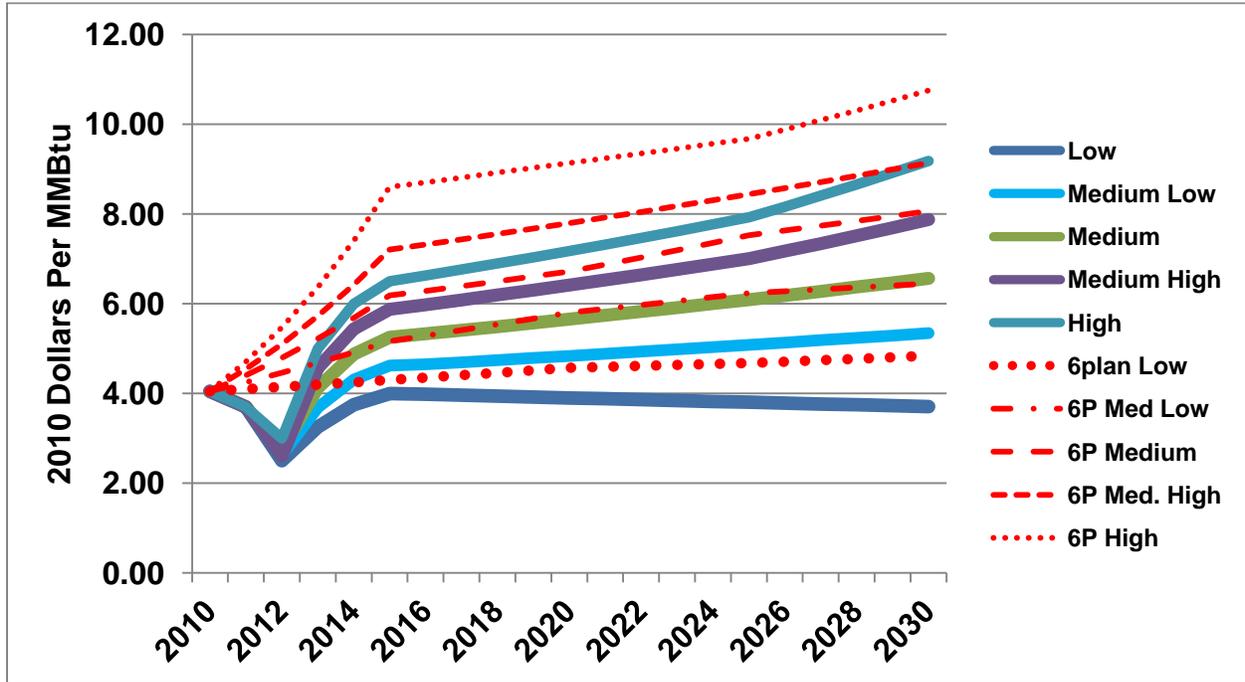


Natural Gas Price Forecast Revisions

Compared to the Sixth Power Plan’s forecasts, the range of natural gas prices in the Council’s latest update is narrower and significantly lower in the near term. By the end of the forecast’s horizon in 2030, the forecasts reflect a range of possible long-term equilibrium natural gas prices. The revised medium forecast is about equal to the medium-low forecast in the Sixth Power Plan at \$6.80 in 2010 constant dollars. The revised high forecast is a little above the medium-high, and the low revised forecast is a little less than \$1.5 below the low case.

The range of forecasts reflects differing views on the supply and demand for natural gas. The high price forecast relates to a rapid economic recovery in the U.S. and worldwide; environmental restrictions on shale gas development; aggressive regulation of carbon emissions leading to more natural gas generation instead of coal; increased use of natural gas vehicles; increased demand for exports of liquefied natural gas from Canada and United States; and increased demand from gas-to-liquid projects. In contrast, the low forecast would be consistent with conditions that limit the demand for natural gas and promote the rapid development of supply.

**Comparison of Revised and Sixth Power Plan Natural Gas Price Forecasts
Wellhead Price (constant 2010 dollars per MMBtu)**



C. Demand for Electricity

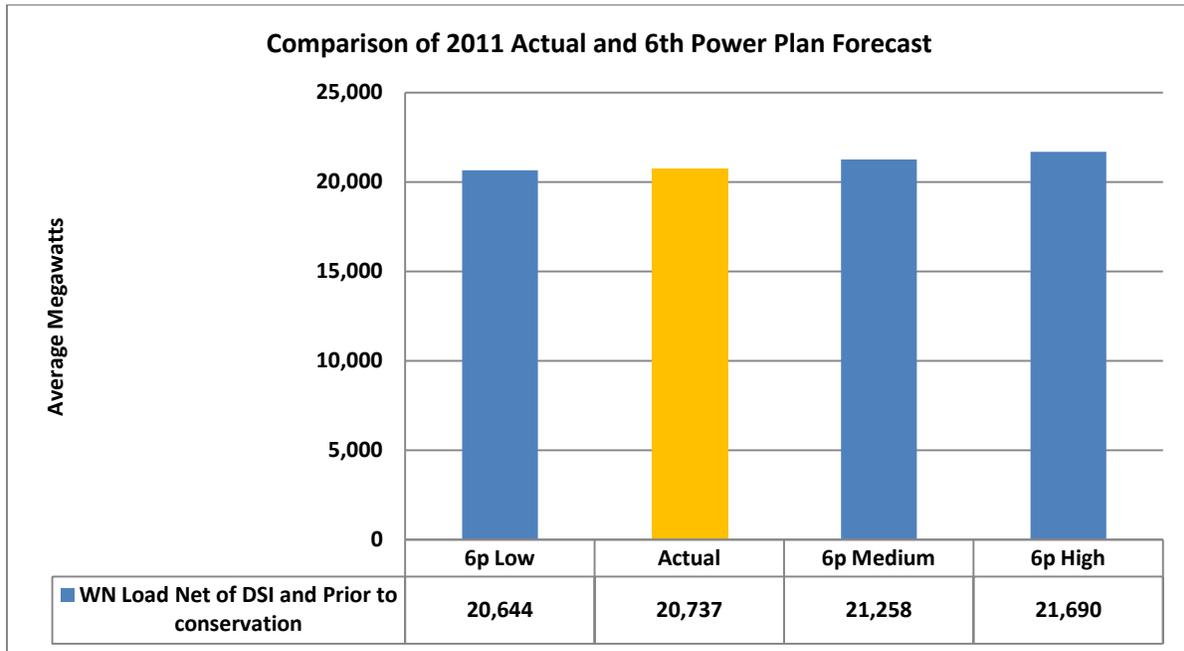
Given the prolonged recession, mild winter and summer in the past two years, and the over 500 average megawatts of acquired energy efficiency, one would expect regional loads to be declining. However, after adjusting for weather, regional loads grew at a modest rate of about 0.8 percent in 2010-2011, and the region should be ready for fast load growth once the economy has fully recovered.

In the Sixth Power Plan, the forecast for average electricity demand for 2011 was between 20,644 and 21,690 average megawatts, once adjusted for direct service industry loads and prior to energy efficiency achievements. Comparing the adjusted actual and forecast demand shows that in 2011 regional loads were within the plan’s forecast range. Adjusted loads are estimated at 20,737 MWa, or about 0.4 percent higher than the low forecast.

Factors contributing to the difference between forecast and actual loads include higher than expected energy efficiency achievements, lower than anticipated demand from direct service industries, mild weather conditions in both 2010 and 2011, and the slow economic recovery.

- In the Sixth Power Plan, the energy efficiency targets were estimated to reach a cumulative total of 440 MWa by 2011, whereas the current estimate is closer to about 518 MWa. This lowered loads by 78 MWa.

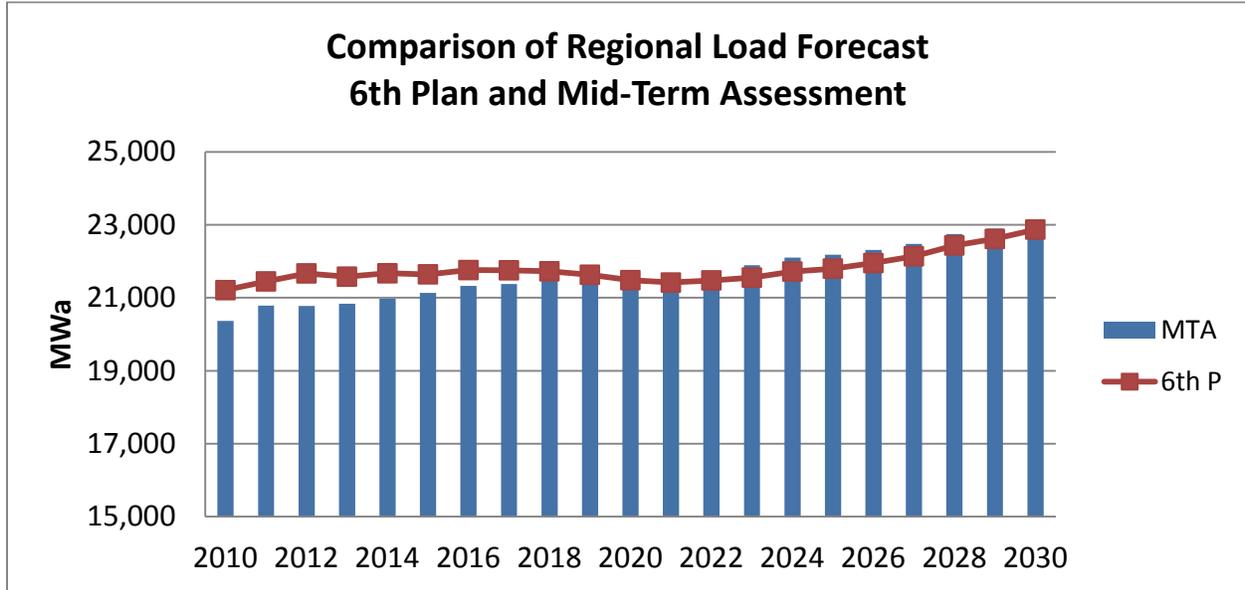
- In the plan, direct service industries were expected to have an average annual load of 676 MWa. Their actual demand in 2011 was closer to 556 MWa, or about 120 MWa lower than anticipated.
- The plan’s demand forecast was not too far off, once adjusted for weather. Analysis shows that loads in 2011 were just 41 MWa lower than forecast.



Implications for the Long-Term Forecast: The demand forecast is influenced by the demand for goods and services. Electricity demand is growing slightly faster than the Sixth Power Plan’s low trajectory. The degree to which the load forecast remains on this trajectory depends on economic growth, population growth, and the level energy efficiency investments. Using the Q2-2012 economic forecasts from HIS/Global Insight, we have revised our long-term forecast for loads. This preliminary revised load forecast remains below the Sixth Power Plan’s medium forecast until about 2020, but starts growing faster, and by 2030 is about 2 percent above the plan’s levels for 2030.

This increase in loads is due in part to growth in data centers, electric vehicles, and industrial load. Also affecting loads is higher than expected energy efficiency achievements in 2010 and 2011. This is reflected in future loads by lowering the remaining energy efficiency targets for 2012-2030.

Figure X: Comparison of Medium Case Forecasts (net of conservation, normal temperature)



Planned enhancements for the Seventh Power Plan:

Two areas of improvement are:

1. Improved forecasts of regional demand for natural gas. The natural gas demand will align with the demand forecast for electricity and will reflect the impact of energy efficiency targets more closely.
2. Enhancing distributed generation forecasting capabilities. For example, the impact of rooftop solar installations will be included in the demand forecast.

D. Wholesale Power Price Forecast

A new wholesale electricity price forecast was developed in late 2012 as part of the midterm assessment. This is an update to the Sixth Power Plan forecast, which was published in early 2010. Since that time:

- Forecasts for demand have been lowered
- Forecasts for natural gas prices have been lowered
- Greenhouse gas emission cost regulation on the federal level has not moved forward
- Regulatory regimes to curb GHG emissions have been implemented in California, British Columbia, and at the Canadian federal level
- State renewable portfolio standards continue to drive development of renewable power in the region, particularly wind
- Regulatory activities in California are acting to phase out older gas-fired steam units; significant portions of the retired production is expected to be replaced within the state

- Several coal unit retirements have been announced for the region and the West, including Boardman, Centralia, Carbon, and Corette

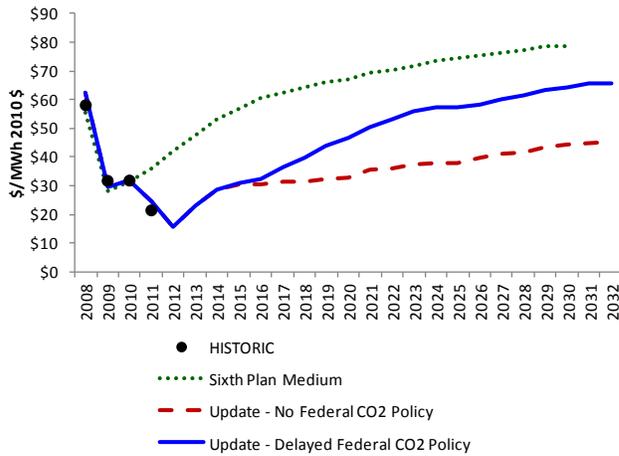
As a result of these changes to the power market landscape, the forecast for wholesale electricity prices in the region differs from the plan’s outlook. Three primary themes emerged from the update to the price forecast:

- Wholesale prices are forecast to be lower than the plan’s medium case
- Natural gas price is a key driver of electricity prices
- The region is relatively clean in terms of GHG emissions from power production, and it’s expected to become even cleaner in the years to come

Low Electricity Prices

Low spot market prices for wholesale power at the Mid C pricing point are expected to continue, but gradually increase over time as the price of natural gas and GHG emission costs rise. Figure 1 displays the updated price forecast at the Mid C for two of the cases (with and without assumed federal GHG regulatory cost policies), along with the plan’s medium forecast and historic prices, all expressed in 2010 dollars.

Figure 1: Wholesale Electricity Price Forecast at Mid C



Large supplies of hydro power in the region, low load growth, significant development of renewable power with low operating costs, and low natural gas prices have combined to keep market prices for electricity low. Continued low spot prices may mute price signals, which could discourage future power generation development in the region. Low prices may also affect avoided cost calculations used for energy efficiency assessments.

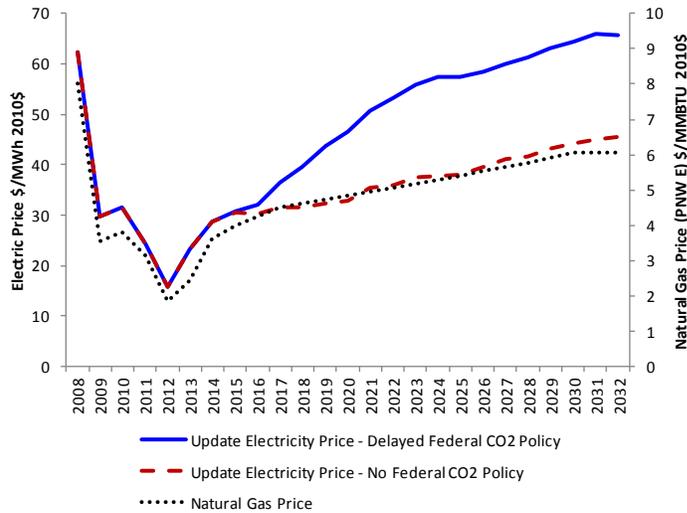
Natural Gas-Fired Generation

Historically, hydro power has accounted for 50 percent to 70 percent of the region’s overall energy production, with gas, coal, and nuclear providing the rest. Because annual hydro conditions can vary, natural gas and coal-fired generation have fluctuated from year to year, and increasing wind generation could add to this pattern. While in the past, coal production has

outstripped that of gas, the forecast results indicate that gas-fired generation could surpass coal for good around the 2021 to 2026 timeframe due to coal unit retirements.

Though gas consumption for power generation in the region may not increase significantly in the future, natural gas prices will continue to exert a strong influence on the price of electricity. This is because gas-fired production is so often on the margin. Figure 2 charts the price forecasts for electricity and natural gas (variable costs) on a separate y-axis, including historic data from 2008 – 2010.

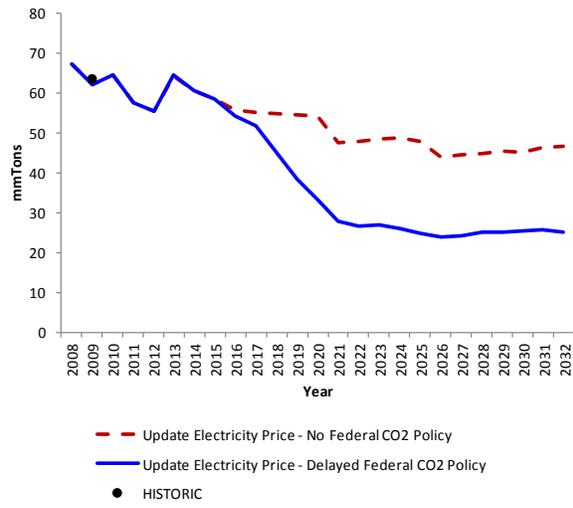
Figure 2: Wholesale Electric Price and Natural Gas Price Forecast at Mid C



Greenhouse Gas Emission Levels

The Northwest power system produces low levels of GHG emissions relative to other regions in the United States due to the abundance of hydro and wind power, as well as energy efficiency. During the midterm assessment, new work was undertaken to model emissions using the same electricity market model developed to forecast prices. The results indicate that the region can expect future GHG emissions to decline, even without a federal GHG regulatory cost policy. This is due to coal plant retirements, state and proposed federal GHG performance standards, along with continued emphasis on energy efficiency, natural gas-fired generation, and continued wind development. Modeling results indicate even lower emissions may result from a cost-based federal regulatory policy on GHG emissions. Figure 3 displays the GHG production forecast for Idaho, Montana, Oregon, and Washington, along with 2009 historic data from the EPA.

Figure 3: GHG emission projections – 4 State Region (ID/MT/OR/WA)



VIII. System Planning – Shifting Emphasis

Power system planning for most regions in the U.S. focuses on ensuring there will be sufficient resources to meet customer needs over the highest demand hour, which usually occurs during a severe cold winter or hot summer weather event. Power systems in those regions are characterized as being 'capacity constrained' or 'machine constrained'. If their resources are adequate to meet peak period demand, they are generally also sufficient to fulfill electricity needs in all other hours. This is because such systems are largely made up of fossil fuel and nuclear resources, whose fuel supplies are relatively abundant and controllable.

However, the Northwest power system is different from most other power systems because of the dominance of its hydroelectric system, which provides 56 percent of the total system generating capacity. But the hydro system has limited water supply and storage capacity. As a result, the Northwest power system is characterized as being 'energy constrained' or 'fuel constrained'.

During the last decade or so, the Northwest power system has become more 'capacity constrained', which means that planners must focus more on meeting peak needs while still providing for longer term energy needs. This change has occurred for a number of reasons.

First, since 1980 more and more operating constraints have been placed on the hydroelectric system. These constraints are mostly to protect and enhance populations of fish and wildlife that were affected by the building of the hydroelectric system. These constraints have the net effect of reducing the hydroelectric system's generating capacity.

Second, the development of wind resources in the Northwest has grown rapidly over the last decade, reaching a total nameplate capacity of 7,183 megawatts as of 2012. Unlike hydro and natural gas-fired generation, the amount of wind power generated during periods of extreme peak demands is uncertain. Thus, it can't always be counted on to meet resource adequacy needs at those times. Further, wind power generation can vary both upward and downward in very short time intervals (less than one hour), which forces utilities to hold more of their dispatchable resources in reserve to aid in balancing demands and resources from minute to minute. This within-hour balancing need has been referred to as a flexibility need or the ability of the power system to quickly respond both upward and downward.

A third reason for this shift is the increase in non-hydro generating resource additions over time. For example, since 2003 nearly 3,500 megawatts of new natural gas-fired generation has been built in the region. As these new resources have been added, hydro generation's share of the region's total portfolio of resources has gradually declined.

Another factor that could affect additional development of Northwest resources is the uncertainty in availability and price of the California market supply. Because of retirements of existing dispatchable generation and the addition of large amounts of renewable resources in California, the future amount of power supply available from California is uncertain. This means that more non-hydro resources may have to be added to the Northwest system in order to maintain an adequate supply.

In order for the current and future power Northwest power system to continue to provide an adequate, efficient, economic and reliable supply, resource planning must also take into consideration the impacts of variable generation resources and the likely diminishing market supply from California. Looking forward, it is apparent that regional power planners will need to focus more on peaking capacity and system flexibility needs. The Council will develop methods to define, quantify and address these needs for the next power plan.

IX. Conclusions

Information-gathering, analysis, and conversations during development of the Sixth Power Plan Mid-Term Assessment have led to the following conclusions:

1. The region is making good progress implementing the Sixth Power Plan. In particular, energy efficiency acquisitions exceeded annual targets for 2010-2011, and the region is well-positioned to meet the plan's five-year goal of 1,200 average megawatts for 2010-2014. Actual costs for energy efficiency acquisitions have remained well below the cost of other types of new resources.
2. Development of renewable resources, mainly wind power, has continued, including for export out of the region. However, California enacted a new renewable portfolio standard in 2011, imposing barriers to out-of-state renewable resources that are likely to dampen future development in the Northwest. Efforts to mitigate wind oversupply events are proceeding.
3. Actual market and electric industry conditions during the first three years of the plan's implementation period have differed from expected-case assumptions. Examples include slower than anticipated growth in economic activity and overall electricity demands, low market prices for natural gas and wholesale power, little activity to regulate greenhouse gas emissions (beyond California and British Columbia) and increasing displacement of coal-fired generation by gas-fired resources.
4. Conditions vary across the region and from utility to utility. Some utilities' loads have been growing and others have had flat loads or have lost large customers. Some utilities have surplus resources and others face deficits. Intra-regional transmission constraints affect utilities' access to wholesale power markets. These factors, as well as variations in service area load densities, availability of contractors, and regulatory and policy directives create differences in utilities' practical and economic incentives to acquire energy efficiency.
5. The Northwest power system has the lowest greenhouse gas emissions intensity of any region in the country. Recent announcements that the Boardman and Centralia coal plants will be closed indicate that the region's GHG emissions will become even lower.
6. An updated analysis shows that with existing resources and projected energy efficiency, the region's adequacy will fall short of the desired level by 2017. While new resources are expected to close this gap, the Council will continue to monitor regional resource adequacy.
7. The character of the region's power system is changing. Historically, needs for new resources were driven mostly by energy deficits. Today, however, needs for peaking capacity and system flexibility are also emerging. For example, the region needs to add new resources to meet its resource adequacy standard in 2017. While progress has been made integrating variable output from renewable resources, growing needs for system flexibility are emerging. Given these trends, it will be important to expand the focus of the region's planning and development of new resources to address peaking capacity and system flexibility.

8. Updated information is needed about the patterns of consumer uses of electricity and how they affect power system needs for energy, peaking capacity, and system flexibility. Information is also needed about how different types of energy efficiency measures could help meet these needs.

9. Spot market prices for wholesale power continue to be quite low, due to increasing penetration of renewable resources with low variable operating costs and low natural gas prices. As a result, market prices for power do not provide an accurate representation of the avoided cost of new resources. This makes the near-term economics of energy efficiency less favorable for some utilities. It can also create challenges for utilities that need to acquire new resources, including peaking capacity and system flexibility.

10. Regional power supply planning matters are becoming increasingly linked with electric transmission and natural gas matters. Various regional, utility industry, and regulatory processes to address these convergence topics are underway. Council participation and analyses can help make these efforts more productive. Results will also need to be incorporated into the Council's planning activities.

X. Candidate Topics for the Seventh Northwest Power Plan

The following list identifies candidate topics that could be addressed in the Council's upcoming Seventh Northwest Power Plan:

1. Making the power plan useful for all regional utilities
2. Regional needs for energy, peaking capacity, and system flexibility
3. Avoided cost benchmarks to evaluate new resources
4. Energy efficiency – how can different types of measures help meet needs for peaking capacity and system flexibility
5. Changing paradigm for energy efficiency; its impact on assessing cost-effectiveness
6. Renewable resources development and integration; impacts on the regional hydro system
7. Demand response
8. Distributed generation
9. Greenhouse gas – regional emissions outlook, regulatory and social costs
10. Incorporating intra-regional transmission constraints in regional power system planning
11. Growth in use of natural gas for electric generation; intersection of planning for the regional power and gas systems
12. Inter-regional linkages, including Northwest and California

Appendix

Sixth Plan Action Plan Implementation Status

December 14, 2012

INTRODUCTION

This document summarizes the status on implementing the Council's Sixth Power Plan. The action plan describes what needs to happen to implement the plan. It focuses on the 2010 - 2014 timeframe and the plan's priorities. Actions are organized by resource areas; conservation, generation, system adequacy, demand response, Smart Grid and transmission. It also includes actions for Bonneville Power Administration, and Council monitoring activities.

ENERGY EFFICIENCY

There are 21 recommendations for energy efficiency in the action plan, organized in these key areas: (1) enhancing the region's ability to acquire the identified efficiency potential; (2) increasing efforts to identify and verify new cost-effective and feasible technologies; and (3) developing regional mechanisms to keep efficiency policies up to date with changing information; track and verify achievements; and adapt regional efficiency acquisition strategies as needed. Progress has been made in all these areas.

The Sixth Plan recommended that resources and budgets should be geared to acquire 1,200 average megawatts of savings between 2010-2014 from utility program implementation, market transformation efforts, and codes and standards. The five-year conservation targets in the Sixth Plan range between 1,100 and 1,400 average megawatts. Utility and Northwest Energy Efficiency Alliance savings outpaced the targets in the plan for 2010 and 2011. In addition, all four states have adopted new energy codes and DOE has issued final standards for 20 products since 2009 many of which will count toward the targets.

Looking forward, some utilities are planning to accelerate conservation and others may be cutting back. Projected 2012-2014 savings reported by utilities taper off somewhat from 2011 levels. There is a high likelihood that the region will achieve over 1200 average megawatts for the five-year period. Utility levelized costs of conservation are below \$20 per megawatt-hour and below Sixth Plan expectations. As a consequence of a reduced 2013-2014 Bonneville efficiency budget, some of its customer utilities may need to increase their local share of efficiency acquisition so Bonneville and its customers can continue to achieve the efficiency goals for 2013 and beyond without increasing its costs.

NEEA and the region's utilities have successfully deployed major new initiatives for ductless heat pumps, TVs, industrial energy management, heat pump water heaters and outdoor lighting. The region doubled NEEA's work scope and its budget. The region committed more resources to the Regional Technical Forum, which has implemented recommendations from the Northwest Energy Efficiency Taskforce, standardizing its processes and making its decision making more transparent. Issues for small and rural utility implementation are being evaluated and discussions are underway to find solutions.

Progress has been made in the regulatory arena, with some utilities incorporating risk premiums in their conservation cost-effectiveness protocols, and discussion of decoupling in Washington and Montana is ongoing. Progress is also being made on expanding and coordinating emerging technology efforts. Progress has been slower on fulfilling data needs, coordinating evaluation research and updating Bonneville's tracking and reporting system for energy efficiency.

The Council completed an analysis on the impact of efficiency performance uncertainty in February 2010. The study found that there is a negligible effect on the efficiency acquisition policy. The average amount of efficiency developed in the least-risk plan is about the same as the case with efficiency certainty. However, the preferred level of optioned wind generation increases conservation uncertainty.

The Council also completed a study of the direct use of natural gas in February 2012. The analysis found that from both a societal and individual consumer perspective, most consumers should remain with their current space and water heating fuels. The study found that there are few cost-effective fuel conversions in space heating. But about one quarter of water heating choices could involve beneficial changes in fuel source. The overall potential effects on gas and electricity use, if all of the cost-effective conversion choices were made, is small.

There are two actions where we have not made progress. No regional strategy to achieve targets and build capability has been developed. No high-level forum for ongoing policy-level guidance on issues of resource allocation between local, regional programs, and market transformation initiatives has emerged since NEET

GENERATION

The action plan found that, from a regional perspective, developing new generating capacity (beyond the requirements to meet state renewable portfolio standards) is unlikely to be needed in 2010-2014. Individual utilities, however, may need to acquire generation capacity because of transmission or other limitations that constrain access to energy markets and surplus generation, or because of a need to reduce exposure from market price, fuel price or carbon risk. The action plan includes guidelines for energy acquisitions.

Chief among those guidelines is that non-renewable resource acquisitions should take into account the growing need for resource flexibility. Whether the region fully appreciates the value and need for flexibility in resource acquisitions remains unclear and controversial. The mid-term assessment provides a review the results and assumptions of the Sixth Plan in light of current power purchase agreements and the resources that have been built, or are expected to be built, during the action plan's five-year planning horizon.

Substantial strides have been made in the region with respect to accessing existing system flexibility and reducing the demand for flexible resources. The Joint Initiative group has begun developing measures to increase the liquidity of intra-hour market trading. A new market assessment and coordination committee, co-chaired by Bonneville and Pacific Power, was

established in March 2012 to better coordinate these efforts, which is a very encouraging sign of progress.

Similarly, efforts to reduce the need for flexibility are underway. Bonneville and other balancing areas introduced half-hour scheduling. Bonneville introduced a 34-percent reduction in needed reserves (and an integration charge discount) for wind projects scheduling at half-hour intervals. Today, Bonneville holds less balancing reserves than it has in the past for a far larger wind fleet; a clear sign of substantial progress.

A few action items are lagging. Progress on facilitating smaller-scale, Northwest-specific low-carbon resources, such as wave energy and advanced geothermal has been slow. Planning for the optimal development of the power system is at a nascent stage, with talks just beginning between Council staff and regional transmission planning organizations on a regionally optimized generation and transmission plan. The effort to promote CO₂ parity between renewable energy and conservation began but was unable to progress.

At the other end of the spectrum, Bonneville analysts were able to develop a synthetic hourly wind data series that will help quantify wind's contribution to meeting regional demand.

BONNEVILLE POWER ADMINISTRATION

Since the Council adopted the Sixth Power Plan, Bonneville has worked with its customers to ensure that it meets its share of the Council's regional efficiency targets while meeting its load obligations in an efficient and cost-effective manner. To facilitate the region's acquisition of efficiency, Bonneville undertook an extensive regional public process that resulted in a framework and set of policies to guide the acquisition of energy efficiency post-2011. Bonneville and the region's public utilities not only met, but exceeded their pro-rata share of the Sixth Plan's efficiency targets for 2010, and early estimates show they likely did the same in 2011. Bonneville is reducing its capital budget for energy efficiency acquisition for fiscal years 2013 and 2014 due to overspending in FY 2011. Bonneville has been working with its customers to ensure that with a renewed commitment to utility self-funding, they can continue to achieve and exceed the Council's targets. Despite the reduced funding for energy efficiency in fiscal years 2013 and 2014, the Council believes Bonneville should continue to offer flexible and workable programs to help utilities meet the efficiency goals, including a backstop role for Bonneville should utility programs fail to achieve them.

Bonneville continues to look at ways to meet the system flexibility required by increasing summer-peak demand and variable resources on the system. It has stepped up its participation in regional efforts to improve intra-hour trading, and has made several significant institutional changes to enhance system flexibility and address the oversupply issue. Although Bonneville is facing ongoing legal challenges to its tiered rates methodology and environmental redispatch policy, it did successfully work with the region's utilities to achieve a residential exchange program settlement agreement that most of the region's utilities (representing 93 percent of power consumed in the Northwest) approved in 2012.

ADEQUACY

There are four action items pertaining to the adequacy of power supply. The Council's mandate under the Act is to develop a plan to ensure an "adequate, efficient, economic and reliable power supply." Adequacy is one part of that mandate. The primary action is to provide an annual assessment of the adequacy of the power supply five years into the future, as an early warning should resource development or efficiency acquisition fall short. The standard used to assess adequacy is incorporated into other analytical models used by the Council.

Other actions include maintaining resource and load data, and working with in-region and out-of-region entities to share information and methods. The fourth action included a methodology review, which was performed between 2010 and 2012. Results from that review prompted the Resource Adequacy Forum to revise the Council's 2008 standard, and in December of 2011 the Council formally adopted its proposed revisions.

Current analysis shows that the power supply would be inadequate by 2017 should no additional resources be acquired. The metric used to assess adequacy indicates the likelihood of shortfalls and is commonly referred to as the loss of load probability. The LOLP for 2017 is 6.6 percent, which is above the maximum level of 5 percent adopted as part of the Council's standard. However, adding 350 megawatts of new dispatchable generation capacity or various combination of generation, efficiency and demand response will bring the LOLP back down to the standard's limit of 5 percent.

DEMAND RESPONSE

Demand response is receiving greater interest than in the past, and utilities and Bonneville are gaining experience with it. The region as a whole has not been short of peak generating capacity, and most utilities are not yet pursuing demand response as a significant resource. However, two utilities with unique circumstances, PacifiCorp and Idaho Power, have pursued demand response aggressively.

Several other utilities, including Avista, Puget Sound Energy, and Portland General Electric have conducted pilot programs to explore the practicality of the resource for their situations in the future, when more peaking capacity is likely to be needed. A larger number of Bonneville's utility customers have joined with the agency in conducting pilot projects.

Bonneville has also funded an innovative study of the use of loads with thermal storage (space and water heaters and refrigerated warehouses) to provide ancillary services (intra-hour balancing) to system operators. The use of loads to provide ancillary services is an area of increasing interest, not only in our region but elsewhere in the nation and the world, and Bonneville's efforts are at the forefront of work in this area.

A new pilot project focused on data centers as a source of ancillary services has been initiated as a Bonneville Technology Innovation project. The Council is contributing to the project, both financially and with staff analytical and consulting services.

Considering loads as a source of ancillary services has suggested new candidates. Pumping in municipal water systems and waste water treatment plants, pulp and paper production, data centers, air separation, and aluminum smelting are a few examples of loads that could contribute to ancillary services, as well as the more conventional purpose of controlling peak demand. For example, while aluminum smelting is a considerably smaller regional load than it was historically, its current load is generally more than 500 MW, contributing 35-70 MW of contingency reserves to Bonneville, and could potentially provide regulation services as well.

The action plan called for completing the work of the Pacific Northwest Demand Response Project, a series of meetings that Council staff and the Regulatory Assistance Project have coordinated since May 2007. Originally, PNDRP's mandate was to make recommendations on actions the region's regulators could take to stimulate demand response, with attention focused on the issues of cost-effectiveness, pricing, and integrating power, distribution, and transmission planning. Over time, the participants have identified other topics of broad interest, and the attendance at PNDRP meetings has consistently been 40-60 people. After consulting with regulators, staff and RAP plan to continue PNDRP meetings as interesting agendas are assembled, probably 1-3 meetings per year.

The action plan also suggested that demand response capabilities should be considered in setting appliance efficiency standards. In the future, Energy Star ratings will include demand response capability as part of the evaluation process.

The action plan called for implementing NEET's recommendations. Those recommendations included increasing regional collaboration on smart grid and load management. The regional smart grid demonstration project includes Bonneville and 11 public and private utilities, and involves both smart grid and load management components. This project, along with the demand response pilots conducted by utilities around the region and the community of interest coming together at PNDRP meetings, has helped to increase communication among those interested in demand response and smart grid in the region.

Finally, the action plan called for improving the Council's modeling of demand response in its planning analysis. Due to limited manpower to devote to this problem, this has not yet been accomplished.

SMART GRID

The smart grid is not a single package of equipment and software that can be adopted and installed in one step, but rather a wide assortment of improved sensing, metering, and communication technology. We can expect that diverse components of the smart grid will be selected by utilities based on their unique needs. The action plan called for demonstrating smart grid technology, and for developing evaluation methods to monitor its progress. This is ongoing, particularly in the regional smart grid demonstration project.

Evaluation methods that apply to all situations seem unlikely; instead, evaluation will need to take into account the combination of smart grid and non-smart grid components that combine to provide value. For example, improved communication and controls may make the operation of a

water heater to provide ancillary services cost effective, but part of the value of the package is due to such components as the non-smart grid mixing valve that lets the water heater operate through a wider range of temperature to take advantage of the full thermal storage potential of the water heater. Developing general principles of evaluation, including treatment of complementary components, may be easier with specific results of some of the projects in the regional smart grid demonstration project.

TRANSMISSION

The Sixth Plan recognized a reduced emphasis on the Council's role since the Fifth Power Plan, as Bonneville and the regional transmission planning entities began taking action on needed transmission expansion. Consistent with the diminished concern over transmission sufficiency, the action plan calls for monitoring progress on transmission activities and costs. Although Council staff has diminished its direct involvement in the myriad of transmission planning activities, a new role for the Council may emerge in the wake of the Federal Energy Regulatory Commission's Order 1000.

The new FERC order requires regional transmission planning entities to better coordinate with one another in producing regionally optimized transmission and generation plans. Historically, transmission and generation plans have been separate, and in recent years transmission lines were built only when sufficient demand was demonstrated for a particular path. FERC's order requires an optimized planning approach and some stakeholders are urging that the Northwest's transmission planning entities work more closely with the Council as an experienced entity in producing regionally optimized power plans.

In response, Council staff has begun conversations with ColumbiaGrid and the Northern Tier Transmission Group about coordinating more closely. The extent to which the Council may become involved in regional transmission planning activities is still unclear, but discussions are expected to continue.

FISH AND WILDLIFE

There are five action items relating to the interaction between planning for power needs and for fish and wildlife operations. The critical action is to ensure that power and fish and wildlife planning are done in a coordinated manner. The Council is to develop its fish and wildlife program and then produce a power plan that ensures that its fish and wildlife program will be implemented.

Because emergencies sometimes occur, the second action is for the Council's fish and wildlife division to produce a contingency plan that would cut back fish operations during a power emergency. The second part of this action is for Bonneville and others to develop a contingency plan to cut back power operations during a fish emergency. To date, no progress has been made on either parts of this action item.

A third action is to review and enhance, whenever appropriate, models used to develop the fish and wildlife program and the power plan. As part of this action, one of the Council's models has

been modified to dynamically simulate the operation of the Canadian hydroelectric system. This allows staff to independently assess the effects of potential changes to the Columbia River Treaty and of potential future changes in temperature and precipitation.

The fourth action item pertains to the Columbia River Treaty and analyses currently being done by the federal entities to assess whether the Treaty should be terminated in 2024. Council staff has participated in various meetings and proceedings but has not been requested to do any independent analysis as of this time.

The fifth action item is to continue to monitor research related to climate change and to work with scientists and federal agencies to develop and maintain a common set of data, which can be used to assess potential future impacts of temperature and streamflow changes. A preliminary set of data is available now but work to update this data is ongoing.

MONITORING

The action plan calls for the Council to monitor conditions in the region for significant changes that would affect the power plan. The mid-term assessment completes that action for the first part of planning period.

ANALYSIS

These items are intended to improve the Council's analytics used in calibrating the long-term model to real world conditions.

Significant progress has been made on getting more timely information on hourly loads and on agricultural sales. But the data on industrial sales by industry group are still outstanding. We are currently working with the Pacific Northwest Utilities Conference Committee to see if it can obtain the necessary sales information from its members.

The progress on filling data gaps identified through the NEET process is mixed. Some hourly end-use data are being collected from a residential sample through NEEA. But no large-scale, comprehensive update to end-use load data has emerged. The RTF is conducting a business case for end-use load data to determine the scope and scale of next steps.

Staff is developing a natural gas demand forecast that reflects electricity demand forecast. This work will be vetted through natural gas and electric utilities and will be presented to the Council at a later date.

Efforts to combine the supply and demand modules of the long-term demand forecast were investigated. Due to the need for hourly electricity market clearing price forecast, it would not be beneficial to maintain two models for forecasting market clearing prices. Peak load forecasting is not being worked on at this time. It may be pushed back to the post mid-term assessment period.

Improvements to transportation modeling were undertaken last year. Modeling work is completed and will be used in developing the next plan.

The GENESYS model has been enhanced to include a dynamic simulation of Canadian hydroelectric projects. Its hourly hydro dispatch logic has also been enhanced to better address peaking and flexibility questions.

Substantial review and development work has been completed on the regional portfolio model. Recommendations from the system analysis advisory committee include adding a new metric for evaluating economic performance, adopting continuous hydro generation operation, and developing a narrative around planning futures, which the model uses to stress-test resource strategies.

Contract work is underway to validate the RPM's internal forecasts of commodity prices and resource adequacy, and to detect any biases that could influence resource strategies. Other areas of RPM development include modeling transmission zones used in other Council models, improved resource capacity and adequacy assessment, and better representation of minimum loading for generation. The hardware platform has been upgraded to streamline processing and is ready for testing.