SIXTH POWER PLAN

Mid-Term Assessment Summary

Northwest Power and Conservation Council
March 15, 2013

Mid-Term Assessment of the 6th Power Plan Summary Outline

Topics

- Background on the Council
- Northwest Power System
- Sixth Northwest Power Plan
- Mid-Term Assessment
- Seventh Northwest Power Plan

Northwest Power & Conservation Council

- Northwest Power Act of 1980 (Public Law 96-501)
- Interstate Compact: Four states, each Governor appoints two members
- A unique agency charged by Congress to: Develop a Northwest Power Plan; Develop a fish and wildlife program; and Public outreach and accountability

Northwest Power System

- Firm output from federal resources is enough to serve about one-third of the region's loads
- Bonneville sells wholesale power to over 120 publicly-owned utilities
- Variability in hydro generation led to development of the nation's first major spot market for wholesale power
- Bonneville built and operates the region's backbone transmission system
- The Northwest has a long-standing history of cooperation and collaboration
- Solutions are developed in the NW to meet regional needs

Northwest Power Plans

- Long-term regional power plan
- Updated every five years
- Electricity demand and price forecasts
- Identifies least-cost, least-risk resources
- Northwest Power Act decrees energy efficiency as the top priority resource to meet future load growth and gives it a 10% cost advantage over other resources
- Bonneville actions must be consistent with the plan

Sixth Northwest Power Plan

- Resource strategy: Meet 85 percent of growth in demand with energy efficiency; Integrate renewable resources the utilities are adding to meet state renewable portfolio standards; Take steps to be ready to add natural gas-fired generation when needs emerge
- Action plan (selected items): Acquire 1,100 – 1,400 average megawatts of energy efficiency during 2010-2014; Increase supply and reduce demand for system flexibility; and Assess and ensure resource adequacy

Mid-Term Assessment

- Primary purpose: check on progress in implementing the Sixth Power Plan
- Developed with extensive public outreach and consultation
- Receiving positive feedback and support from a broad range of stakeholders
- 'Tees up' issues for the upcoming Seventh Power Plan

Mid-Term Assessment Developments Since 2010

- Energy efficiency achievements in 2010-2011 exceeded targets, at very low costs – 530 aMW at less than $20 per megawatt-hour
- Market prices for natural gas and wholesale power are low
- Retirement of coal-fired plants have been announced; will require development of new generating resources
- A number of forces are driving reductions in greenhouse gas emissions, even with less than expected GHG regulation
- The region's utilities face varying circumstances
- Progress is being made on integrating wind power
- The regional power system's peaking capacity and flexibility are becoming constrained

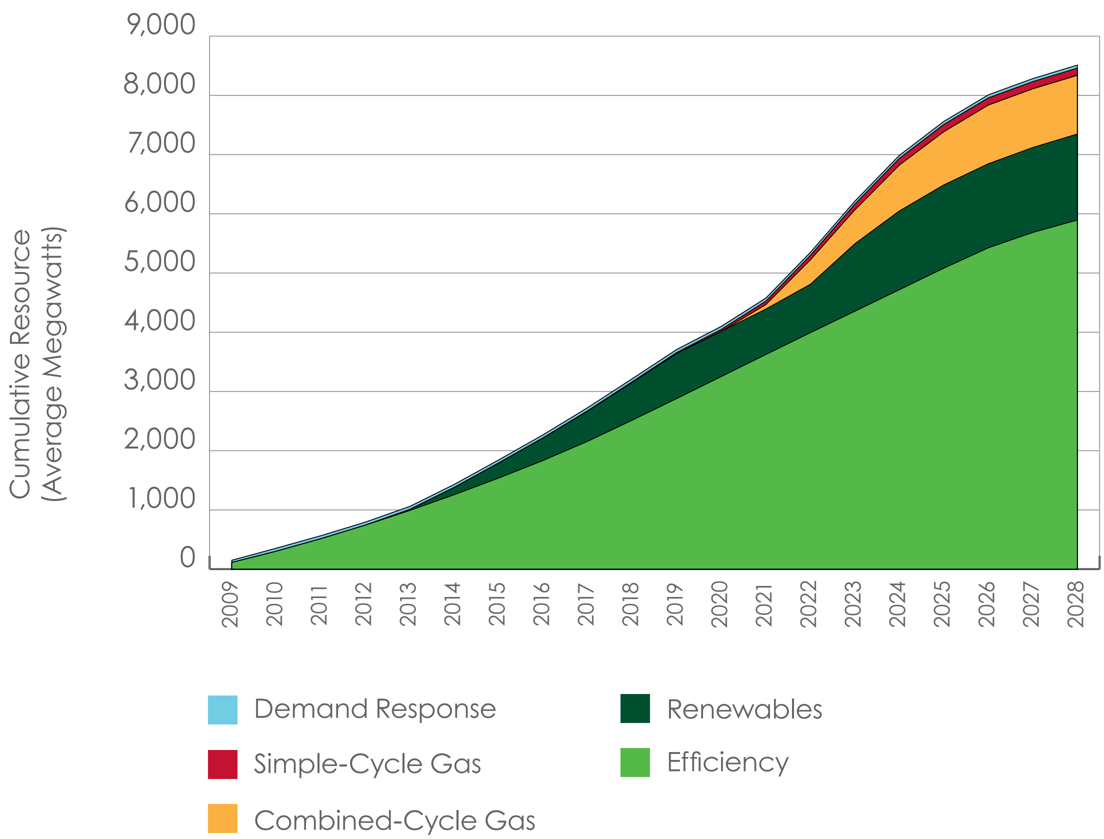
Seventh Northwest Power Plan Candidate Topics

- Make the power plan useful to utilities with differing circumstances
- Regional needs for energy, peaking capacity and system flexibility
- Energy efficiency to meet energy, capacity and flexibility needs
- Resource avoided costs, determining cost-effectiveness
- Customer demand response
- Distributed generation
- Renewable resources development and system integration
- Greenhouse gas – regional emissions, regulatory and social costs
- Reflect intra-regional transmission constraints
- Intersection of power and natural gas system planning
- Inter-regional power system and market linkages

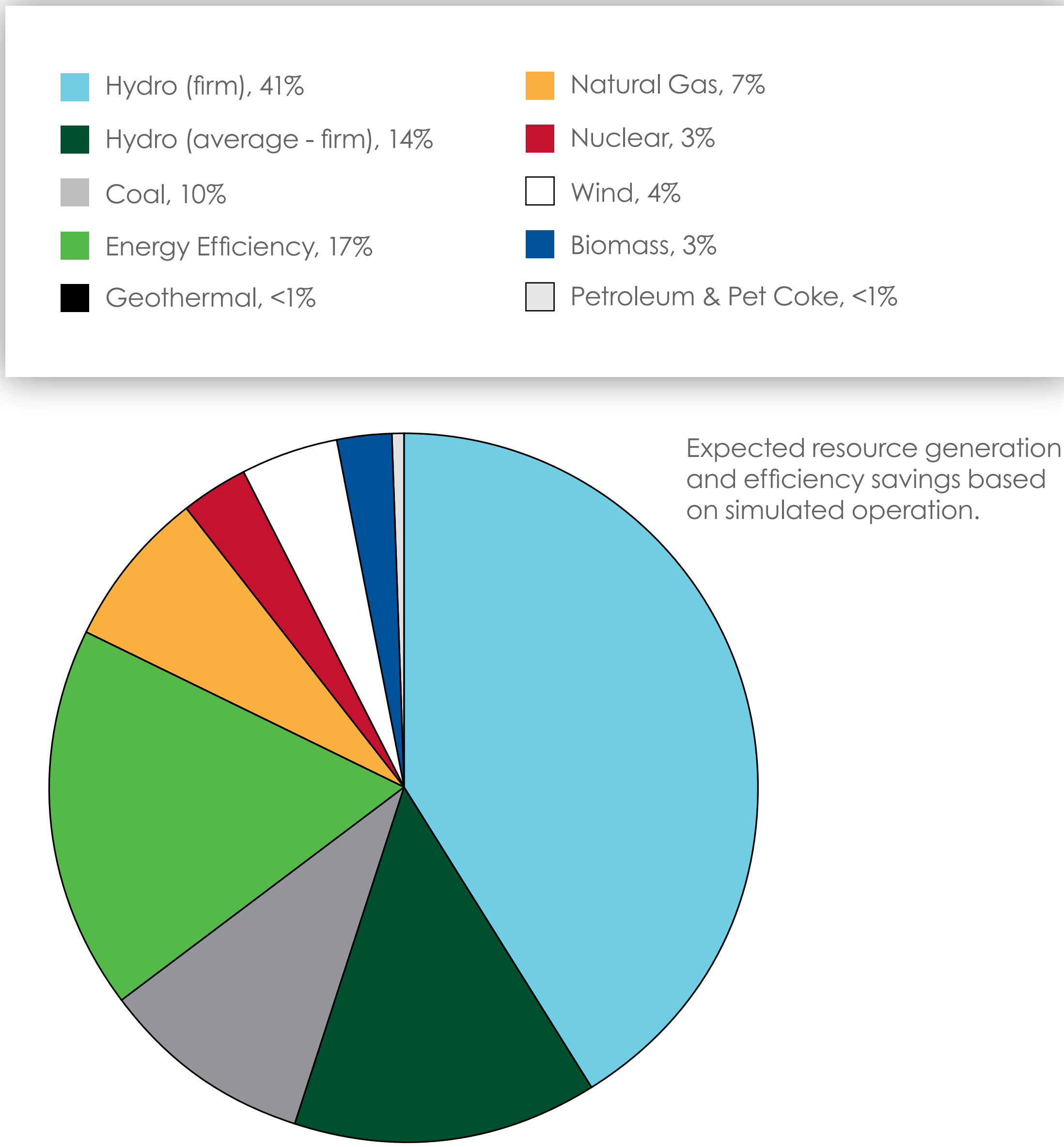
Seventh Northwest Power Plan Tentative Schedule

- Scoping: Spring 2013
- Key Inputs: Summer 2013 - Fall 2013
- Portfolio Analysis: Winter 2014 - Spring 2014
- Draft Plan: Summer 2014
- Public Review: Fall 2014
- Council Adoption: Winter 2015

Planned Resource Additions in the Sixth Power Plan



Northwest Power System Energy Resources in an Average Hydro Year



Northwest Power System Situation Scan March 2013

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
16. Columbia River Treaty Review

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, regional electricity demand increased by 651 average megawatts; 533 average megawatts of the demand growth was met with new energy efficiency resources and loads increased by 118 average megawatts.

While overall regional loads appear to be gradually returning to pre-recession levels, the increase has been slow. 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.

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 averaged about $2.75 per MMBtu for 2012, significantly below the plan's 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 U.S. Department of Energy is currently forecasting wellhead gas prices to average about $3.53 per MMBtu during 2013, compared to the plan's forecast of $5.40 per MMBtu.

The Council 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. At other times, higher natural gas prices have been triggered by reduced supplies or increasing 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 did not pass. Future regulation of GHG emissions through new federal legislation remains a possibility, but its timing and likelihood 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; its startup has been delayed to 2013.

Meanwhile, it's become apparent that other policy and market developments have the potential to accomplish the objective of reducing GHG emissions, particularly from the electric utility sector. Much of the focus of these changes centers 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. And 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, including:

- 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 the costs to continue 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 proposed 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. This includes major companies in the Powder River Basin of Wyoming that have 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, 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.

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 increase the need for new resources.

In May 2010, the California Water Resources Board adopted a statewide water quality control policy to meet the federal Clean Water Act's requirement to use the best technology available in power plant cooling processes. This 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.

Much 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, and fast responding simple-cycle combustion turbines that will provide capacity and help integrate renewables.

Also affecting the California market, both units at the San Onofre Nuclear Generating Station, 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's not clear whether or when this major source of generation will be come back on line. If the 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 also reduce 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 to meeting peak demands and solar generation is typically much higher during summer months, which means less capacity would be available during the Northwest's 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 from 3,200 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 continue to unfold, causing market prices for natural gas to remain at lower than expected levels. 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. Third, renewable resource development has exceeded expectations, adding new generating resources whose output is subject to variability.

The combination of large amounts of new renewable resources and large supplies of hydroelectric generation, which both have low variable operating costs, is helping drive spot market prices for wholesale power down to very low levels more often.

These and other factors (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 affect the region's utilities differently. 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 depend 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 illustrated during the 2001 Western energy crisis. 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. With the exception of energy efficiency, this is below the typical cost to develop new resources. 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 the tier 2 rate 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 just over 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 certain manufacturing facilities were shut down. For example, Snohomish County PUD recently lost a big portion of its industrial load when customer Kimberly-Clark was forced to close its mill in early 2012.

Some utilities now find themselves with power supply resources that exceed their retail customers' demands. For these utilities, low spot market prices for wholesale power reduce the revenues they generate from sales of surplus power, putting pressure on utility budgets. In turn, this can create upward pressure on the utility's retail electric rates.

Meanwhile, a number of utilities have not yet exceeded their entitlements to purchase power from BPA at tier 1 rates. These utilities face lower near-term price signals than the cost of new resources. Consequently, their short-term economic incentives to acquire new energy efficiency resources at costs above the tier 1 rate are reduced.

On the other hand, the region has been a hotbed 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. For example, 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 entitlement to purchase power from BPA at tier 1 rates.

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.

As noted above, low spot market prices for wholesale power can be detrimental for utilities with surplus resources. However, low market prices can be beneficial for utilities whose long-term resources (including tier 1 purchases from BPA) are not sufficient to meet their retail customer demands. Purchases from the short-term wholesale market can be a low-cost source of power to help fill these utilities' deficits. This can create an economic incentive to rely on short-term market purchases as an alternative to making long-term investments in higher-cost new resources.

The region acquired 254 average megawatts of new efficiency resources in 2010 and 277 average megawatts in 2011, exceeding the Sixth Power Plan's goals of 200 average megawatts for 2010 and 220 average megawatts for 2011. 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. Approaches to acquire energy efficiency must be tailored to meet their unique needs, and Bonneville, NEEA, and the Council's Regional Technical Forum have established work groups and policies to accomplish this.

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 be built in Snohomish County since the early 1980s. 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.

This target is part of the plan's energy efficiency and generation resource strategy called for in the Northwest Power Act. Bonneville has a corresponding obligation under the Act to implement efficiency measures and acquire resources "consistent" with the Council's power plan, including energy efficiency targets. For the rest of the region, the targets are important for other reasons, but without the same legal obligation.

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 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.

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. Primarily in response to reduced economic activity, Idaho Power recently asked the Idaho Public Utility Commission to suspend two of their programs while they discuss with DR participants and the commission how to reduce costs without sacrificing the DR resource they expect to need when economic activity recovers. Discussions are ongoing on this issue.

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 in the next 10 years.

The Pacific Northwest Demand Response Project hosted a discussion of how to evaluate energy efficiency and demand response in industrial facilities.

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 (nonnegative) 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 (pending 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 and capacity, as well as help balance variable output from other resources, including wind power.

As gas-fired generation 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 questions about the adequacy of the natural gas system to serve 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; this has established strong dialog and closer coordination
- During the summer of 2012 and in February 2013, 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 to ensure gas infrastructure remains adequate

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.

Fortunately, it is becoming apparent that our region's natural gas infrastructure is relatively robust when compared with other regions. For example, the

Northwest has more underground gas storage capacity than some other regions. In addition, deliverability from interstate pipelines has not been significantly impacted by regional shifts in gas production due to rapid growth in shale gas production, as may be occurring elsewhere. Further, the great majority of natural gas-fired generating facilities in the Northwest have firm pipeline capacity rights, fuel-switching capability or both.

16. Columbia River Treaty Review

One of the uncertainties with the Pacific Northwest power supply over the next decade is the fate of the Columbia River Treaty, the agreement with Canada executed in the early 1960s under which 15 million acre of feet of Columbia River runoff is stored in reservoirs in British Columbia and managed primarily for flood control and power generation optimization.

Under the treaty, the annual assured flood control operations end in 2024, to be replaced with a "called upon" flood control operation of few details and uncertain effect. Unless the two nations agree to a new arrangement for flood control, there is a good chance flood control operations at both the U.S. and Canadian storage projects will change significantly, with uncertain effects on the hydropower output.

The treaty's provisions governing coordinated operations do not change automatically in 2024. But either nation may terminate the Treaty beginning in 2024, with at least 10 years' notice. Continuing the treaty retains the certainty and value of the coordinated power operation, including the ordinary operations that add energy and capacity to meet winter needs, as well as the ability to coordinate proportional drafting of upriver reservoirs to meet summer needs in low-flow years. But it also means continuing what seems an increasingly out-of-date method for calculating the downstream power benefits of the Canadian operation known as the Canadian Entitlement, which many believe does not align with the real benefits and burdens of the power system operations. It also keeps the power operation provisions from the 1960s that, while not completely inflexible, still make it hard to coordinate operations with today's regional and westwide power system.

On the other hand, terminating the treaty seems unlikely for a number of reasons. And while termination would bring obvious benefits to the U.S. part of the system by being able to retain the power now shared as the Canadian Entitlement, the U.S. would also lose the certainty of coordinated operations and relatively certain flows. Other considerations include the incidental flood risk management benefits from the winter power draft, a real concern given the loss in 2024 of the annual assured flood control operation. Also at issue is how to integrate ecosystem needs more systematically into the international operation; there is no agreement as of now about what that would mean for actual operations.

The main point for this assessment is that the region is heading into a period of uncertainty after many decades of relative certainty and international cooperation. A modified cooperative arrangement that continues to allow for the Canadian storage projects to be operated in a coordinated fashion but also meets the needs of the 21st century is likely a far better scenario than either continuing or terminating the treaty. But the treaty itself does not allow explicitly for modification, and the process to revise a cooperative arrangement is itself fraught with uncertainty.

The Bonneville Power Administrator and the Corps of Engineers' Northwestern Division Engineer (the designated U.S. Entities under the treaty) have joined with other federal agency, state, and tribal personnel to review the treaty options in an effort to shape a rough consensus on the desired future of the international arrangement, with the target to submit a recommendation to the State Department by September 2013. The Province of British Columbia is leading a similar review. Currently, there are no negotiations between the two nations, but an opportunity for transboundary discussions by 2014 or 2015 might well result. The Council should have a better sense of the implications for the power system of changes to the treaty in time for the Seventh Power Plan.

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