

CHAPTER 2: STATE OF THE NORTHWEST POWER SYSTEM

Contents

Introduction	2
Key Findings	2
State of the System.....	5
Regional Economic Conditions	5
Electricity Demand.....	5
Natural Gas Markets and Prices	7
Emissions Regulations and Impacts	8
Developments Affecting Power Imports from California	9
Wholesale Power Markets and Prices	12
Implementation of Bonneville Tiered Rates.....	13
The Region’s Utilities Face Varying Circumstances.....	14
Energy Efficiency Achievements.....	15
Demand Response Activities	16
Renewable Resources Development.....	16
Additions and Changes to Fossil-Fueled Generating Resources	17
Hydroelectric System Operational Changes	18
Shifting Regional Power System Constraints.....	19
Power and Transmission Planning	20
Power and Natural Gas System Convergence.....	21
Columbia River Treaty Review	22



INTRODUCTION

All planning processes start with information and assumptions about current conditions. This chapter summarizes the key assumptions regarding the state of the region that affected the Council's power system planning process or could potentially influence its implementation.

For example, the Northwest Power Act requires the Council's power plan to include a forecast of electricity demand for the next 20 years. Demand, to a large extent, is driven by economic growth, but it is also influenced by the price of electricity and other fuels. Therefore, recent economic trends and energy prices represent a starting point for plan development.

The Northwest Power Act also requires the Council's power plan set forth a forecast of the region's power resources need, including that portion that can be met by resources in each of the priority resource categories identified in the Act. Since the power plan treats cost-effective energy efficiency as a priority resource for meeting future electricity demand, an assessment of its potential must reflect recent accomplishments and factors, such as the impact of codes and standards on future demand. Similarly, assessments of the need for resource development must account for the status of existing generating resources, including planned additions and retirements.

In addition to the state of the region's economy and status of conservation and generating resources, other factors such as environmental regulations, public policy and technology trends also influence plan development. For example, recently finalized federal carbon dioxide emission regulations and changes in California's regulations, such as the state's renewable portfolio standards, may alter energy prices and wholesale market supplies.

The following discussion describes the key assumptions used as the starting point for the Council's analysis. For many of these assumptions, while the current status is known, there is significant uncertainty about the future. That uncertainty creates risks that are addressed in the Seventh Power Plan's resource strategy, set forth in Chapter 3.

KEY FINDINGS

- Since 2011, regional employment has grown by over 500,000 jobs per year. During the last five years, gross state product for Idaho, Montana, Oregon, and Washington increased by \$110 billion (2012\$). The regional economy grew at a nominal annual rate of 2.26 percent per year during 2010 to 2014.
- While overall regional loads have gradually returned to pre-recession levels, the increase has been slow. Regional electric loads finally returned to pre-recession levels in about 2014. On a weather-adjusted basis, total regional loads (excluding direct service industries or DSIs) reached a high of 20,454 average megawatts in 2008. This is identical to the regional weather-adjusted loads reported for 2014. However, since these loads are net of the energy-efficiency accomplishments over this period, they mask a far more robust underlying growth rate. Between 2010 and 2014, regional electricity efficiency savings totaled over 1500 average megawatts, exceeding the Sixth Power Plan's five-year goal of 1,200 average megawatts by 25 percent. Without those savings,



regional loads, exclusive of the DSIs, would have grown from 20,111 average megawatts in 2010 to 21,611 average megawatts in 2014, or by nearly 8 percent over five years.

- While the region's highest peak loads still occur during the winter months, summer peak demands are growing faster than winter peak demands. In fact, winter peak demands have not grown significantly since 1995, while summer peaks have been increasing at about 0.4 percent annually. Nevertheless, for the region as a whole, winter peak capacity is forecast to remain the more significant need for at least the next 10 to 15 years.
- The Council's forecast for future natural gas prices over the next twenty years spans a range from a low of \$3.56 per MMBtu to a high of \$10.00 per MMBtu by 2035. This is a lower range of future gas prices than was used in the Sixth Power Plan.
- In June of 2014, the Environmental Protection Agency (EPA) released its draft regulations limiting carbon dioxide emissions from existing power generation facilities under section 111(d) of the Clean Air Act. These regulations were finalized in August of 2015 and call for a 32 percent reduction in carbon dioxide emissions by 2030 compared to 2005. Along with releasing its final regulations for existing generation facilities, the EPA issued its final regulations limiting carbon dioxide emissions from *new* power generating facilities under Section 111(b) of the Clean Air Act. States have until 2018 to develop plans for complying with these new carbon dioxide regulations.
- Both the Sixth Power Plan and this plan include summer bypass spill requirements identified in the FCRPS Biological Opinion and also in the Council's 2014 Fish and Wildlife Program. Since the Sixth Power Plan, the bypass spill requirements have been adjusted to better reflect the intent of the biological opinion. While bypass spill continues to reduce the generation of the hydro system, these modifications have little impact on summer hydroelectric generation relative to the Sixth Power Plan. However, increasing reliance on the hydroelectric system to provide within-hour balancing needs¹ for wind generation has diminished the system's use to meet peak needs.
- In the Northwest, the retirements of three existing coal-fired plants serving the region have 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. In April of 2015, NV Energy announced the retirement of the 522 megawatt North Valmy plant, which serves a portion of Idaho Power Company's load. In addition, the J.E. Corette coal-fired power plant which does not serve the region, but is located in Montana, shut down in August of 2015.
- Also since 2010, one of region's non-utility owned existing natural gas plants, the 248 megawatt Big Hanaford combined cycle turbine in Washington State, has been retired as have the Elwha and Condit small hydroelectric power plants.

¹ For more information on balancing needs see Chapter 9 and Chapter 16.



- Since the Sixth Power Plan was adopted in early 2010, three new natural gas-fired generating resources have been added in the region. The largest 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. Portland General Electric built the 220 megawatt Port Westward II, a generating set of twelve reciprocating engines, in 2014 and is currently building the Carty Generating Station, a new 440 megawatt combined-cycle project at Boardman which is expected to be in service in 2016.
- From 2010 through 2014, 4,230 megawatts of wind nameplate capacity was added to the region – with nearly 2,000 megawatts coming online in 2012 alone. By the end of 2014, wind nameplate capacity in the region totaled about 8,700 megawatts. However, only about two-thirds of that nameplate capacity currently serves Northwest loads. The remaining one-third (~3,000 megawatts) of wind nameplate capacity is presently contracted to utilities outside the region, primarily California.
- 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. 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.
- The region exceeded the Sixth Power Plan's five-year goal of 1,200 average megawatts of energy efficiency for 2010-2014 by 25 percent, achieving over 1,500 average megawatts of energy and approximately 2500 megawatts of peak savings. Actual average utility costs for energy efficiency acquisitions have remained well below the cost of other types of new resources and wholesale market prices.
- 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 these system needs in addition to energy. Since 2000, about 5,900 megawatts of natural gas-fired generation has been added in the region. During that same period, about 8,700 megawatts of wind power has also been built in the region. The large increase in wind generation has meant that utilities must hold more resources in reserve to help balance demand minute-to-minute; hence the need for system flexibility has become a concern. The Council estimates that the region will have sufficient generation and demand side capability on its existing system to meet balancing and flexibility reserve requirements over the next six years if the Seventh Power Plan's energy efficiency and demand response development goals are achieved. The mechanism for accessing this capability, however, may not be available to all Balancing Authorities depending on market structure/availability.
- 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 resources, including energy efficiency.



- Regional power supply planning matters are becoming increasingly linked with electric transmission and natural gas matters, requiring greater coordination.

STATE OF THE SYSTEM

Regional Economic Conditions

Employment and job creation in the Pacific Northwest remained sluggish during 2010 and 2011, growing from 6.11 million jobs in 2009 to 6.14 million jobs in 2011, adding just 150,000 jobs each year. Since 2011, however, employment has grown by over 500,000 jobs per year to 6.3 million jobs in the region in 2014. During the last five years, gross state product (expressed in constant 2012 dollars) for Idaho, Montana, Oregon, and Washington increased from about \$560 billion dollars in 2010 to about \$670 billion in 2014, a net increase of \$110 billion. Based on these figures, the regional economy grew at a nominal annual rate of 2.26 percent per year during 2010 to 2014.

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 towards less energy-intensive industries.

Forecasts used for the Seventh Power Plan showed the region's economy growing at a fairly healthy pace, consistent with long-term historical trends. The region's population is projected to grow to over 16 million by 2035 at an annual rate of 0.9 percent. Regional personal income, both in total and on a per-capita basis, has been on the upswing and is projected to continue, although at a slower rate. From 1989 through 2009 regional personal incomes grew by about 3.9 percent per year. The Seventh Power Plan forecasts personal income growth to average 2.9 percent per year over the coming two decades. Between 2015 and 2035, commercial employment is expected to grow at an annual rate of 0.9 percent, with total employment growing from 6.4 million in 2015 to about 7.7 million by 2035.

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

Electricity Demand

Between 2010 and 2014, regional electricity weather normalized loads, inclusive of the Direct Service Industries or DSIs (the large industrial customers historically served directly by Bonneville) increased slightly, growing from 20,617 average megawatts to 21,164 average megawatts. This five year increase of just under 550 average megawatts represents a total growth of just over 3 percent. If these large customer's loads are excluded, regional electricity loads grew from 20,111 average megawatts in 2010 to 20,454 average megawatts in 2014. This is an increase of 343 average megawatts or just under 2 percent growth over five years.



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 DSIs) reached a high of 20,454 average megawatts in 2008. This is identical to the regional weather-adjusted loads reported for 2014. Thus, regional electric loads finally returned to pre-recession levels in about 2014.

However, since these loads are net of the energy-efficiency accomplishments over this period, they mask a far more robust underlying growth rate. Between 2010 and 2014, the Council estimates, based on Bonneville, utility, Energy Trust of Oregon, and NEEA reporting, that regional electricity efficiency savings totaled over 1,500 average megawatts. Without those savings, regional loads, inclusive of the DSIs, would have grown from 20,617 average megawatts in 2010 to 22,660 average megawatts in 2014, or by nearly 10 percent over five years.

While the region's highest peak loads still occur during the winter months, summer peak demands are growing faster than winter peak demands. In fact, winter peak demands have not grown significantly since 1995, while summer peak demands have been increasing at about 0.4 percent annually. At least two of the region's investor owned utilities, Idaho Power Company and Portland General Electric, have summer peak demands that are higher or nearly equivalent to their winter peak demands. Nevertheless, for the region as a whole, winter peak capacity is forecast to remain the more significant need for at least the next 10 to 15 years.

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. The Seventh Power Plan forecasts that electricity use by data centers could increase from their current level of 350 to 400 average megawatts to as much as 900 average megawatts by 2035. More recently, as a result of the legalization of cannabis production in Washington and Oregon, indoor agriculture is anticipated to contribute to between 100 and 200 average megawatts of increased electricity demand over the next twenty years. The Council's Seventh Power Plan also anticipates significant growth in electricity use in the transportation sector, forecasting that plug-in electric vehicles could add 160 to 625 average megawatts to regional electricity use by 2035, a significant increase from 8 average megawatts of load in 2015 created by the region's over 22,000 existing electric vehicles.

Acting in the opposite direction are the anticipated impacts of new federal appliance, lighting, equipment standards and distributed solar photovoltaic (PV) systems. More than 30 new and revised federal standards have been enacted since 2010. These standards are forecast to reduce future load growth by nearly 1500 average megawatts over the 20 year period covered by the Seventh Power Plan.

The increasing adoption by homeowners and businesses of distributed solar PV systems are also forecast to dampen regional load growth. As of the end of 2014, over 100 megawatts of distributed solar PV capacity had been installed in the region, lowering system energy requirements by an estimated 18 average megawatts. By 2035, the Council forecasts that 500 to 1,400 megawatts of solar PV systems will be installed in the region. On an annual basis, the energy generated from these distributed PV systems is forecast to reduce regional loads by 80 to 220 average megawatts. In addition, these distributed solar PV systems also reduce winter and summer peak loads. Summer peak impacts from distributed solar PV are forecast to be lower by as much as 600 megawatts by 2035.



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 \$8.24 per million British thermal units (MMBtu) in 2008, fell by more than half to \$3.76 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 \$4.78 per MMBtu in 2010 and \$5.07 per MMBtu in 2011. These forecasts turned out to be higher than actual market prices, which averaged \$4.53 per MMBtu in 2010 and \$3.91 per MMBtu in 2011.

Beginning in mid-2011, monthly wellhead gas prices fell fairly rapidly, reaching a low of \$1.98 per MMBtu for the month of April 2012 before rebounding after that. Annual average prices averaged about \$2.59 per MMBtu for 2012, significantly below the Sixth Power Plan's forecast of \$5.10 per MMBtu.

The decline in market prices reversed and began to increase in April 2012, but since late 2014 prices began to decline due to a crash of world oil prices and glut of natural gas production from U.S. shale plays. Wellhead prices in 2014 averaged about \$3.84 per MMBtu (in 2012 dollars). As of January 2015 the outlook for 2015 composite wellhead prices was \$3.60 per MMBtu. Since January 2015, oil and natural gas prices have declined further. By September 2015, wellhead prices declined to \$2.70 per MMBtu (in 2012 dollars).

The U.S. Department of Energy's (DOE) Annual Energy Outlook 2015 forecasts Henry Hub gas prices will average about \$3.63 per MMBtu during 2015. DOE forecasts that by 2025, Henry Hub gas prices will increase to \$5.35 per MMBtu. By 2035, DOE forecasts natural gas prices will range from a low of \$4.00 per MMBtu to a high of \$8.64 per MMBtu. The final Seventh Power Plan uses a bench mark price of natural gas at Henry Hub of \$2.64 per MMBtu for 2015 and a range forecast of \$2.60-\$3.70 per MMBtu in 2016. However, the Council's forecast for future natural gas price over the next twenty years spans a wider range; from a low of \$3.60 per MMBtu to a high of \$10.00 per MMBtu by 2035.

Increasingly, because of its low prices and apparent adequate supplies, 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.

This has raised concerns about methane emissions from the natural gas production, storage and transportation sectors. During the development of the natural gas price forecast, the issue of



increased reliance on natural gas was discussed by the Council's Natural Gas Advisory Committee. In the judgment of the advisory committee, the Council's high range of the gas price forecast was sufficient to reflect the potential regulatory cost of reducing methane emissions.

Emissions Regulations and Impacts

Since the Council issued the Sixth Power Plan there has been extensive environmental regulatory activity that affects the electricity industry, much of it (but not all) relating to the production of electricity from fossil-fueled and especially coal-fired power plants. The list includes:

- Clean Air Act/national ambient air quality standards: The EPA has adopted more stringent standards for NO₂, SO₂, and particulate emissions, and proposed more stringent standards for ground-level ozone, all of which affect coal-fired power plants.
- Clean Air Act/regional haze rule: Continuing assessments and modifications of coal plants are required.
- Clean Air Act/ mercury and air toxics rule: The U.S. Supreme Court recently struck down and remanded the rule to the lower appellate court for further review. Regardless of the appellate court's decision, the EPA is not likely to substantially alter the rule. Many coal-plant owners have already invested in compliance measures.
- Resource Conservation and Recovery Act/fly ash regulation: In 2015, the EPA issued a new final regulation for handling coal combustion residuals, including boiler bottom ash, fly ash (ash carried in the flue gas), boiler slag, and products of flue gas desulfurization
- Clean Water Act/proposed revisions to effluent standards: In 2013, EPA proposed revisions to the standards for effluent from steam-electric power generation. The purpose is to strengthen existing controls and reduce wastewater discharges of toxic materials and other pollutants, including mercury, arsenic, lead and selenium, from especially coal-fired generation. The final rule was issued on September 30, 2015.
- Clean Water Act/cooling water intake regulations finalized: The EPA recently issued final regulations establishing new requirements for cooling water intake structures in order to protect aquatic organisms.
- Clean Air Act / carbon dioxide emissions regulations: Most notably, EPA finalized regulations under Sections 111(b) and 111(d) of the Clean Air Act limiting carbon emissions from new and existing fossil-fueled power plants. The Section 111(d) regulations call for a 32 percent reduction in carbon dioxide emissions by 2030 compared to 2005. The regulations are the subject of litigation.²
- Nuclear Regulatory Commission regulations: In the wake of the Fukushima Reactor accident in Japan, the Commission is requiring upgrades to existing nuclear power generating facilities to better prepare for external events beyond ordinary design criteria.

² U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," 80 Fed. Reg. 64,662 (October 23, 2015). A coalition of states, utilities, utility organizations and others challenged the rule applying to existing sources in the federal D.C. Circuit Court of Appeals. The U.S. Supreme Court stayed the effectiveness of the rule in an order issued February 9, 2016, pending not just review on the merits by the court of appeals but also the resolution of any petition for further review in the Supreme Court following whatever decision is issued by the court of appeals. The litigation is ongoing as the Council completed the Seventh Power Plan.

- Clean Air Act/development of regulations to reduce fugitive methane emissions from the production and transportation of natural gas.
- Developing regulatory environment to protect eagles and other migratory birds from threats posed by the development and operation of wind and solar generating facilities.

Details about these regulatory efforts and their impacts are discussed elsewhere in the power plan, including Appendix I. Noteworthy here, is the collective effect of these environmental regulatory efforts, especially on the region's coal-fired power plants. In addition to the federal regulations, Northwest states' policies on carbon emissions and other environmental impacts have all but eliminated construction of *new* coal-fired generating facilities as an option for meeting future resource needs. The issue for the regional power system is the effect of the announced retirements of *existing* plants, and the effect on the power system of state and federal policies that may lead to the retirement of other existing plants.

The U.S. Energy Information Administration's (EIA's) Annual Energy Outlook 2014 (AEO2014) Reference Case projects that a total of 60 gigawatts of capacity will retire by 2020, which includes the retirements that have already been reported to the EIA. Retirements are being driven in some cases by the costs of complying with new environmental regulations or the need to reduce greenhouse gas emissions. 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.

In the Northwest, the retirements of three existing coal-fired plants serving the region have 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. In April of 2015, NV Energy announced the retirement of the 522 megawatt North Valmy plant, which serves a portion of Idaho Power Company's load. In addition, the J.E. Corette coal-fired power plant which does not serve the region, but is located in Montana, shut down in August of 2015.

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 and Missoula in Montana.

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 adopted 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 are expected to reduce generation by an additional 1,030 megawatts.

Much of the retiring capacity in California 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. Retiring capacity is also being replaced in California with 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 (SONGS), with about 2,200 megawatts of nameplate capacity, were taken out of service in January 2012 due to excessive wear in steam generator tubes. In June of 2013, the decision was made to retire the SONGS units.

Based on this information regarding California resources and considering California's load projections, the Council's Resource Adequacy Advisory Committee recommended limiting available on-peak spot market imports to 2,500 megawatts during winter and none during summer. A review of historical south-to-north intertie transfer capability for winter months led the advisory committee to also recommend limiting the maximum south-to-north transfer capability to 3,400 megawatts.

Prior to the development of the Seventh Power Plan, the Council commissioned a study of market supplies available from California. The Energy GPS³ study concluded that power surpluses from California during winter months are highly likely to exceed the south-to-north intertie transfer capability.

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

³ Belden, Tim and Turkheimer, Joel, "Southwest Import Capacity", June 12, 2014, see www.nwcouncil.org/energy/resource/home/.

generation from outside California to meet the requirements. In September of 2015, the California legislature increased the minimum requirement to 50 percent by 2030. Many California utilities are already serving 20 percent or more of their customers' needs with renewable energy.

In order to meet these increasing renewable portfolio standards (RPS), California utilities have been increasingly turning to solar power development, as costs for photovoltaic systems have been falling rapidly. In 2014, solar power plants in California produced 10,555 gigawatt-hours (GWh) or 5.35 percent of the state's total electricity production. In August of 2015, California recorded its highest solar output to date, with 6,341 megawatts of solar capacity contributing to meeting that states electricity needs. The large scale of solar development in California, however, presents significant challenges for power system operations and affects Northwest power markets.

Since the RPS are based on an energy metric (i.e. RPS resources must meet a minimum share of annual retail electricity sales) and both solar and wind generation only operate a fraction of the hours in a year, the peak output of such systems is significantly (3 to 6 times) higher than the average output. As a result, integrating these resources into the existing power system requires that generation (usually gas-fired) must be ready to ramp-up or ramp-down to offset increases or decreases in wind and solar output. This gas-fired generation cannot be used to provide other types of reserves when it is designated for integration.

Separate from the physical integration challenges associated with increasingly larger amounts of wind and solar generation on the system, is the impact that these low-variable cost resources have on wholesale market prices. The spring and early summer months are when Northwest hydroelectric generation peaks due to spring runoff. This is also the period of the year when both wind and solar generation tend to be at their highest. The coincidence of the peak output of all three renewable resources, hydro, solar, and wind, can produce extremely low market prices due to supply far outstripping demand.

Unfortunately, wind resources contribute little 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, 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 using summer-only demand response programs to help reduce its summer resource needs. This may reduce the amount of thermal generation peaking capacity available to serve Northwest loads in winter.

The final development affecting the California market's influence on the Northwest is that in June of 2014 the California Independent System Operator (CAISO) won approval from the Federal Energy Regulatory Commission (FERC) to expand its real-time energy imbalance market (EIM) beyond state borders, with PacifiCorp and NV Energy the first to join. In addition to PacifiCorp and NV Energy, at least three other non-California utilities, Portland General Electric in Oregon, Washington's Puget Sound Energy, and Arizona's Arizona Public Service have signed agreements to participate in the CAISO's EIM. All of the Northwest utilities had been participating in negotiations to create a regional EIM through the Northwest Power Pool.

Among the most significant issues raised by the CAISO's expanded footprint is whether it will grow into something more than a simple energy imbalance market that could lead to improved operational efficiencies for the 38 independently operated balancing authorities in the western interconnection.



Such developments were too speculative to consider in the analysis supporting the Seventh Power Plan, but could be a significant issue for the Eighth Power Plan.

Wholesale Power Markets and Prices

For the Seventh 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 Sixth Power plan was adopted in early 2010, developments across all three of these areas have occurred that will directly impact future wholesale power market prices. First, the supply-side impacts of shale gas continue to unfold, causing market prices for natural gas to remain at low levels. Second, there are now federal regulatory mechanisms to reduce greenhouse gas emissions. Third, renewable resource development has added significant amounts of new generating resources whose output has very low variable operating cost. The combination of large amounts of new renewable resources in the Western wholesale power market and large supplies of hydroelectric generation, both of which have low variable operating costs, is producing very low spot market prices for wholesale power more often.

These and other factors (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 \$26 per megawatt-hour during the period July 2014 through June 2015. In contrast, average prices for calendar year 2008 were 240 percent higher. The Council's Seventh Power Plan forecast for spot market prices ranges from an average of \$25 per megawatt hour to an average of \$68 per megawatt hour over the next twenty years.

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 to keep power 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 the period from April 2011 through 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.

Implementation of Bonneville Tiered Rates

In October 2011, the Bonneville Power Administration implemented tiered rates for its sales of wholesale power to the region's public utilities. Bonneville'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, Bonneville'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 Bonneville'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 Bonneville, 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 Bonneville's tier 1 power is roughly \$32 per megawatt-hour. With the exception of energy efficiency, this is below the typical cost to develop new resources. Ninety of Bonneville's public utility customers are projected to exceed their tier 1 allocations in 2017 and thus will have to acquire additional resources.⁴ The prospect of exceeding their tier 1 allocation in the future may already be influencing their behavior. There is anecdotal evidence that some utilities are taking action to avoid spot market purchases. So to a certain extent, tiered rates are achieving the intended purpose of providing more efficient pricing signals to Bonneville's utility customers.

However, prices for wholesale power purchased in the wholesale market remain relatively low, often below the cost of new resources or even below Bonneville'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 Bonneville or utilities purchase power in the short-term market to meet their incremental resource needs, this mutes the tier 2 price signal.

Finally, there is also the matter of whether and how the price signal provided by Bonneville'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. By incorporating Bonneville's price signals, 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.

⁴ http://www.bpa.gov/power/pl/regionaldialogue/implementation/documents/docs/Formatted_Tables_RHWM_Process_2016_FINAL.xlsx

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 are new, reflecting an ever-changing operating environment. As a result, the needs and incentives to acquire new resources also vary among the region's utilities.

Continued economic stagnation, particularly in the region's rural areas, has meant low overall load. Poor economic conditions have also triggered the loss of existing industrial loads as certain manufacturing facilities were shut down. For example, Snohomish County Public Utility District 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, those utilities that have not yet exceeded their entitlements to purchase power from Bonneville at tier 1 rates 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. Several of the Mid-Columbia public utility districts have also seen significant growth as new data centers locate in their territory.

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 Bonneville at tier 1 rates.

The first Centralia and Boardman coal-fired power plants will be retired in 2020 and the second Centralia and North Valmy coal-fired power plants will be retired in 2025. These planned retirements will eventually increase regional and individual utilities' needs for new resources, particularly among the region's investor-owned utilities.

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 Bonneville) are not sufficient to meet their retail customers' 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, including energy efficiency.

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. Approaches to acquire energy efficiency must be tailored to meet their unique



needs. Pursuant to actions recommended in the Sixth Power Plan, Bonneville, NEEA, and the Council's Regional Technical Forum established work groups and policies to address those needs. In addition, Bonneville also established a low-income working group to address the needs of those consumers in the region who lack the means to participate in utility programs but may have significant opportunities for energy efficiency in their residences.

Energy Efficiency Achievements

The Sixth Power Plan identified a range of likely energy efficiency resource acquisition during 2010 to 2014 of between 1,100 and 1,400 average megawatts. Within this range, the Sixth 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 surpassing the high end of the expected savings range.

Over the first five years of the Sixth Power Plan, the region's utilities, the Bonneville Power Administration, Energy Trust of Oregon, and Northwest Energy Efficiency Alliance (NEEA) acquired nearly 1,300 average megawatts of efficiency. In addition to the savings acquired by the utilities, Bonneville, Energy Trust, and NEEA, all four states recently adopted new building energy codes. NEEA estimates that improvements in state energy codes have produced 18 average megawatts of savings over the last five years.

Another significant contributor to savings in recent years is due to the adoption of minimum efficiency standards for energy-using products. Since 2009, the federal Department of Energy has issued final product standards for more than 36 products ranging from refrigerators to utility transformers. Some of these standards took effect in between 2010 and 2014, producing about 50 average megawatts of additional savings during that period. States have also begun to adopt minimum standards for products not covered by federal standards, such as battery chargers.

In addition, consumer uptake of efficient products, outside of direct utility-funded programs, has been particularly strong for lighting equipment since 2010. In part, this consumer uptake is due to prior utility programs pushing efficient products into markets and in part it may be due to consumer preference. Together, minimum product standards and consumer uptake added about 220 average megawatts of documentable savings outside of direct utility-funded programs in the 2010 to 2014 period.

All told, between utility-funded programs, state codes and standards, federal standards, and consumer uptake, the region captured just over 1500 average megawatts of energy and approximately 2500 megawatts of peak savings during 2010-2014, achieving 125 percent of the Sixth Power Plan goal and surpassing the high end of the expected energy savings range.



Demand Response Activities

The two regional utilities with the most experience in acquiring and using demand response (DR), PacifiCorp and Idaho Power, have continued to expand and refine their programs. Both are now exercising control over 700 megawatts of their in-region peak loads. While other regional utilities have not acquired DR to this extent, some are gaining experience with it. PGE has contracted for 28 megawatts of DR in the industrial and commercial sectors, and continues to conduct pilot programs, currently focusing on the residential sector. BPA continues to explore pilot programs and demonstration projects in cooperation with its utility customer, Energy Northwest, and EnerNOC, testing the capability of DR resources to provide winter peak reductions, within-hour balancing of variable energy resources, and strategic transmission relief. BPA has also arranged for 35 to 100 megawatts of contingent reserves to be provided by industrial customers.

Puget Sound Energy and Avista have both conducted demand response pilot programs in the recent past. However, while both companies have identified the technical potential of demand response and evaluated DR as part of their resource planning process, neither of these utilities is currently acquiring DR resources.

Renewable Resources Development

Since the adoption of the Sixth Power Plan, renewable generating resources development has increased significantly. This development was prompted by renewable portfolio standards (RPS) adopted in three of the four Northwest states and in California. Wind energy has been the principal focus of renewable resource development in the Pacific Northwest. From 2010 through 2014 about 4,100 megawatts of wind nameplate capacity was added to the region, with nearly 2,000 megawatts of capacity coming online in 2012 alone. By the end of 2014, wind nameplate capacity in the region totaled just over 8,700 megawatts. However, only about two-thirds of that nameplate capacity currently serves Northwest loads. The remaining one-third (~3,000 megawatts) of wind nameplate capacity is presently contracted to utilities outside the region, primarily California.

Snohomish PUD began producing power from its 7.5 megawatt Youngs Creek run-of-river hydroelectric project in October 2011. It is the first new hydroelectric power plant to be built in Snohomish County since the early 1980s.

As noted above, 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, and recently increased to 50 percent by 2030. 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, actual results have been generally consistent with the Sixth Power Plan. The Sixth Power 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 between the Sixth Power Plan and this Seventh Power Plan in terms of renewables development include the following:

1. While the Sixth Plan assumed renewable resources would be developed to meet 95 percent of RPS targets, recent experience suggests most utilities are actually achieving 100 percent (and sometimes more) of their target levels several years in advance of the requirement.
2. Construction of renewable resources to serve the California market is expected to slow, if not end completely.

The quantity of reserves on the Bonneville system to provide balancing services has remained relatively constant, 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 oversupply events, Bonneville 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 but it could not spill additional water without exceeding Clean Water Act limits on dissolved gas levels.

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 and the last Bonneville oversupply event was in 2011.

Meanwhile, as noted, costs for solar photovoltaic generation have dropped dramatically during the last several years. In the Sixth Power Plan, the Council estimated that solar photovoltaic generation would cost about \$254 per megawatt hour. The Seventh Power Plan's estimated cost of solar photovoltaic generation located in Southern Idaho now ranges from as low as \$61 to \$91 per megawatt hour – a 64 to 76 percent cost reduction. 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 has improved such that in the best Northwest sites (e.g., Southern Idaho), the levelized cost of solar production is lower than the levelized cost of wind generation.

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 Sixth Power 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 region-wide analysis.

Since the Sixth Power 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. Portland General Electric built the 220 megawatt Port Westward II, a generation set of twelve reciprocating engines, in 2014 and is currently building the Carty Generating Station, a new 440 megawatt combined-cycle project at Boardman which is expected to be in service in 2016.

Since the adoption of the Sixth Plan some utilities have issued requests for proposals (RFPs) to acquire generating resources. An informal survey conducted for the Mid-Term Assessment Report (2012-13) identified RFPs calling for over 3,100 megawatts of conventional generating resources, including base load, 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 (PSE) and TransAlta announced a power sales contract that will supply base load generation from the Centralia coal-fired plant to PSE from December 2014 to December 2025, including 380 megawatts of coal-fired generation during the period 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. More recently the retirement of the 522 megawatt North Valmy coal plant in Nevada scheduled for 2025 was announced as well as the closure of the 172 megawatt J.E. Corette coal plant in Montana in 2015. In addition to coal plant retirements, the 248 megawatt Big Hanaford combined cycle natural gas generator, a non-utility owned plant, was taken out of service in 2014. The replacement of the energy and capacity lost as a result of these retirements is addressed in the Seventh Power Plan's resource strategy.

Hydroelectric System Operational Changes

The operational flexibility and generating capability of the Columbia River Basin hydroelectric system has been reduced since 1980 primarily due to efforts to better protect fish and wildlife. Over the past thirty years, the pattern of reservoir storage and release has shifted some winter river flow back into the spring and summer periods during the juvenile salmon migration period. In addition, minimum reservoir elevations have been modified to provide better habitat and food supplies for resident fish. The results of these changes have reduced the hydroelectric system's firm energy generating capability by about ten percent or by roughly 1,100 average megawatts. Most of these changes have occurred between 1980 and the early 2000s. More recent summer bypass spill requirements, identified in the FCRPS Biological Opinion and included in the Council's 2014 Fish and Wildlife

Program, for example, do not significantly affect hydroelectric generation. Since about 1995, the hydroelectric system's peaking capability devoted to meeting firm load has dropped by about 5,000 megawatts. This is due, in part, to the high development of wind resources and the correspondingly greater allocation of hydroelectric system capability toward providing within-hour balancing needs.⁵

Shifting Regional Power System Constraints

In most of the other regions of the country, 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, about 5,900 megawatts of natural gas-fired generation has been added in the region. During that same period, over 8,700 megawatts of wind power has also been built in the region. The large increase in wind generation has meant that utilities must hold more resources in reserve to help balance demand and resources minute to minute; therefore, the need for system flexibility has become a growing concern. The Council estimates that the region will have sufficient generation and demand side capability on its existing system to meet balancing and flexibility reserve requirements if the Seventh Power Plan's energy efficiency and demand response development goals are achieved. The mechanism for accessing this capability, however, may not be available to all Balancing Authorities depending on market structure/availability.

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

⁵ For more information on balancing needs see Chapter 9 and Chapter 16.



periods of strong runoff and robust winds, competition between the two can drive spot market prices to very low levels.

The region is making progress developing a variety of additional mechanisms to integrate wind power, including recent activity in the region and California regarding the establishment of a sub-hourly energy imbalance market. Improving market liquidity across balancing authorities is likely to have a positive effect on 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.

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; and
- Increasing costs to transmit and integrate renewable and other new generating resources.

In response, various activities and initiatives have been undertaken:

- Federal Energy Regulatory Commission (FERC) Order 1000 requiring transmission planning and cost allocation;
- Western Electricity Coordinating Council (WECC) Transmission Expansion Planning Policy Committee (TEPPC);
- Changing roles for WECC (pending division into two organizations);
- Planning activities of Columbia Grid, Northern Tier Transmission Group (NTTG), California Independent System Operator; and
- 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; and
- Cross-checking for consistency of major inputs to power and transmission planning studies.

The Council continues to work with ColumbiaGrid to identify areas for coordination and to improve coordination with other organizations, including WECC, TEPPC, and NTTG.

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 5,900 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 existing 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. Challenges resulting from increased use of gas-fired generation which are being addressed in regional and national forums include:

- 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; and
- 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.

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 the treaty, Canada agreed to build three projects in the portion of the Columbia River in British Columbia that stores more than 15 million acre feet of Columbia River runoff. BC Hydro manages the treaty storage projects primarily for flood control and power generation optimization. The U.S. delivers to Canada a share of the downstream power benefits known as the Canadian Entitlement, calculated by a method set forth in the treaty and an accompanying protocol. This delivery ranges from 1,176 to 1,369 megawatts (MW) of capacity and 465 to 567 annual average megawatts (aMW) of energy.

Under the treaty, the annual assured flood control operations ends in 2024, to be replaced with a "called upon" flood control operation which has yet to be specified in any detail. 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 after 2024, affecting generation patterns as well.

The treaty's provisions governing coordinated power operations do not change automatically in 2024. Either nation may terminate the treaty beginning in 2024, with at least 10 years' notice.

The Bonneville Power Administrator and the Corps of Engineers' Northwestern Division Engineer (together the designated U.S. Entity under the treaty) joined with other federal agency, state, and tribal personnel from 2011-13 to review the current treaty and recommend changes. Out of this effort came the "U.S. Entity Regional Recommendation for the Future of the Columbia River Treaty after 2024," delivered to the State Department in December 2013. The U.S. Entity regional recommendation recommended neither termination nor the status quo, calling instead for the two nations to negotiate a "modernized" treaty with modifications that respond to the current issues with flood control, coordinated power operations, ecosystem needs, and the calculation and sharing of benefits. The Province of British Columbia led a similar review, and produced what it called its "Columbia River Treaty Review: B.C. Decision" at the same time. Neither the U.S. State Department nor Foreign Affairs Canada has responded officially to the regional recommendations. The NW



region is waiting for confirmation from the U.S. State Department that they are ready to begin negotiations which could commence within the year.

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. For the purposes of the Seventh Power Plan, it is impossible to know at this time whether and how storage operations in Canada and thus flows across the border may change after 2024, nor what changes may need to be made to storage operations at U.S. projects, both affecting the generation output and patterns of the system. Nor is it possible to know whether and to what extent there will be a change in the power benefits the U.S. will deliver to Canada in the future. This is a level of uncertainty the Council needs to consider in its resource planning.

