CHAPTER 9: EXISTING RESOURCES AND RETIREMENTS

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KEY FINDINGS

Over the course of the Council's three and a half decades of existence, the Northwest power supply has seen some dramatic changes. The Council was created, in part, because of a fear in the late 1970s that regional demand for electricity would quickly outgain the power supply's capability. That did not turn out to be the case and the Council's first power plan was developed to address a short-term generating surplus instead of the perceived deficit.

During the late 1980s and into the 1990s, the electric industry was convinced that the "market" would incentivize capital development of generating resources. This also did not turn out to be the case and very little generating capability was added during the 1990s. By 2001, due to the failure of the California market and the second driest year on record in the Northwest, the region faced a severe energy crisis. It survived but only by securing very expensive temporary generating capability and, most dramatically, paying to curtail service to aluminum smelters – all of which lead to significantly increased electricity rates.

The years between 2001 and 2005 saw increased activity in resource development and by the Council's Sixth Power Plan, the region was more or less again in a load-resource balance. This short history of the region's power supply illustrates the difficulties planners have in forecasting future needs and subsequently developing proper strategies to cover potential changes in those future needs.

Today the hydroelectric system remains the cornerstone of the Northwest's power supply, providing about two-thirds of the region's energy, on average. Over the last five years, a larger share of its generating capability has been allocated to providing within-hour balancing reserves, thereby reducing what can be deployed to meet firm load. This is a direct result of the high rate of wind resource development in the region since 2010.

One of the Council's key accomplishments over the last 35 years has been its support for the implementation of nearly 5,800 average megawatts of energy efficiency – equivalent to over 15 percent of the region's firm energy generating capability. Over the past five years, the region has achieved just over 1,500 average megawatts of energy efficiency savings, exceeding the Sixth Power Plan's five year goal of 1,200 average megawatts from 2010 to 2014.

As mentioned above, the region has seen a very rapid development of wind generation, with roughly 8,700 megawatts of wind capacity built over the last ten years – including about 2,000 megawatts installed in 2012 alone. This development was prompted in large part by renewable portfolio standards adopted in three of the four Northwest states (Washington, Montana, Oregon). In Idaho, the Public Utilities Regulatory Policy Act (PURPA) has also played a major role in wind development. It appears, however, that the rapid development of wind seen over the past ten years is likely to slow down over the next five-to-ten year period.

Over the past five years, about 520 megawatts of new gas-fired generating capability was added, with another 440 megawatts or so expected to be completed by 2017. During the same period, TransAlta's Big Hanaford combined-cycle gas-fired power plant and the Elwha and Condit small hydroelectric power plants were all retired. PPL Montana announced the permanent retirement of its J.E. Corette coal plant scheduled for late 2015. In 2020, Portland General Electric plans to cease coal-fired generation at Boardman and TransAlta will retire one of its units of its Centralia coal plant in 2020 and the second unit in 2025. NV Energy has announced the retirement of the North Valmy coal plant, which is co-owned by Idaho Power Company, scheduled for 2025.

Political pressure to decrease generation from carbon-producing resources has prompted development of more carbon-free resources and efficiency measures. One of the challenges for the Council's plan is to identify strategies to maintain an adequate, efficient, economic, and reliable power supply in a future with increasing shares of variable resources and smaller more widely distributed sources of energy supply.

THE PACIFIC NORTHWEST POWER SUPPLY

Existing Generating Resources

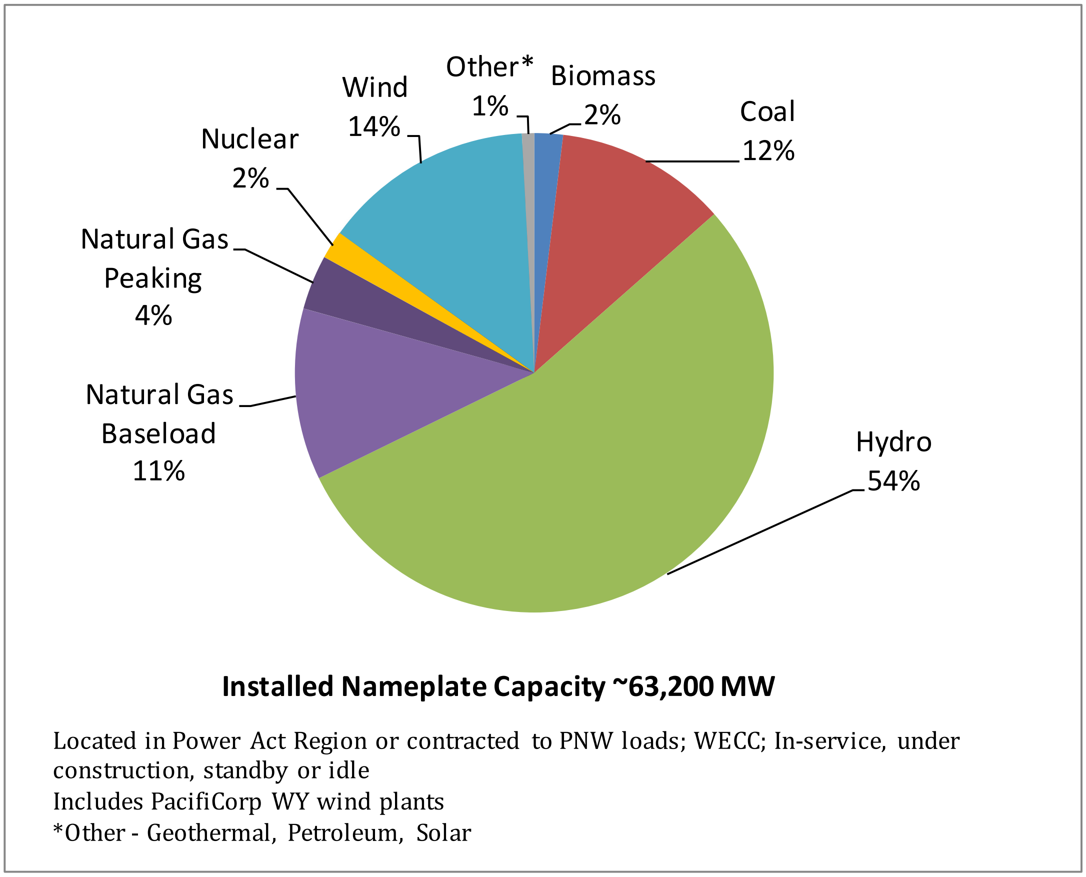
The 2016 regional power supply is still dominated by the hydroelectric system, although its share of total generating capability has decreased since 1980, mostly due to the addition of a significant amount of non-hydroelectric resources. However, during that same period, hydroelectric generating capability has also been reduced because of increasing operating constraints to benefit fish and wildlife and because more of its capability has been allocated toward providing balancing reserves to cover the growing number of wind turbines.

Figure 9 - 1 shows the breakdown of the region's existing generating resources by type, as a percentage of total installed nameplate capacity. Second to hydroelectric capacity, which contributes 54 percent of the total, gas-fired resources provide about 15 percent of the total, with peaking units contributing about 4 percent and base-loaded units making up the other 11 percent. Wind generation is the next largest capacity component with 14 percent of the 63,200 megawatt total. Coal generation comes next providing 12 percent of the total installed nameplate capacity.

Unfortunately, characterizing each resource type's contribution based on nameplate capacity can be misleading because nameplate capacity is not always a good indicator of useable capacity. In particular, for both hydroelectric and wind resources, nameplate capacity is not an accurate indicator of peaking capability. For example, only five percent of Northwest wind resource nameplate capacity is assumed when analyzing plans to meet future peaking needs. Thus, on a firm capacity basis, wind only provides about one percent of the total system firm peaking capability.[1] Hydroelectric peaking capability is also much smaller than its nameplate capacity. This is because most hydroelectric facilities in the region have limited storage behind their reservoirs. Moreover, the peaking capability of the hydroelectric system depends on the duration of the peak event – the longer the duration, the smaller the peaking capability. For example, the region's hydroelectric system's nameplate capacity is about 33,000 megawatts but it can only produce about 26,000 megawatts of sustained peak over a two-hour period. Its four-hour peaking capability drops to about 24,000 megawatts and over ten hours, it can only provide about 19,000 megawatts of firm capacity.

[1] Firm peaking capability refers to an amount of generating capacity (in megawatts) that can be dispatched with a high level of confidence during peak demand hours.

Figure 9 - 1: Pacific Northwest Electricity Power Supply – Installed Nameplate Capacity



A better assessment of how much each resource contributes to meet Northwest loads is to compare each resource's energy generating capability with that of the entire power supply. Figure 9 - 2 shows the breakdown by resource for average energy generating capability.

In 1983 the hydroelectric system made up 78 percent of the region's firm energy generating capability (12,350 average megawatts of hydroelectric compared to 3,563 average megawatts of thermal).[2] Today the hydroelectric system's share of the regional total is much smaller. Compared to 78 percent in 1983, hydroelectric generation now makes up about 40 percent of the total system firm energy generating capability (11,600 average megawatts of hydroelectric to about 18,500 average megawatts of thermal, wind, and solar). But firm hydroelectric generation is based on the driest period on record (critical hydro) due to its low storage-to-runoff-volume ratio[3] and other factors.

[2] The First Northwest Conservation and Electric Power Plan, 1983, Chapter 6
[3] The U.S. portion of reservoirs in the Columbia River Basin can only store about 15 percent of the annual average river volume runoff.

Figure 9 - 2 shows average hydroelectric generation, which makes up about 47 percent of the total power supply's energy generating capability.

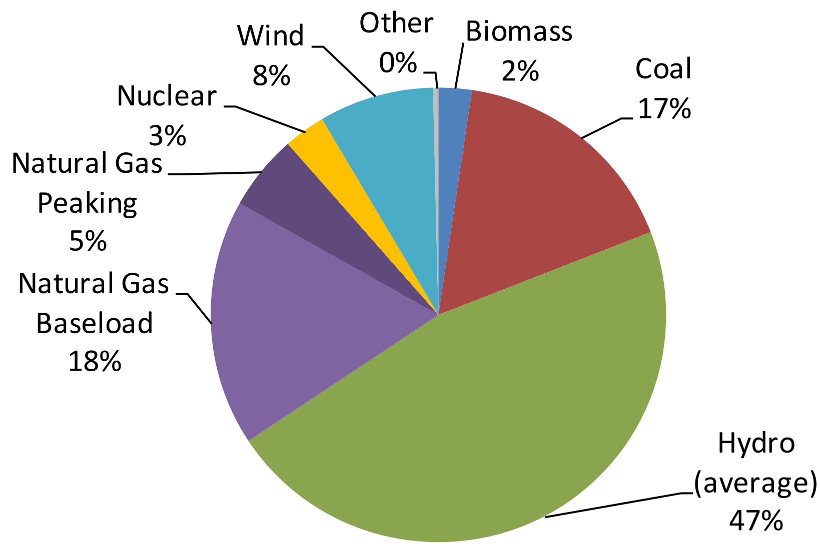
Following hydroelectric generation, the second largest source of energy generating capability is natural gas-fired generation, which provides about 23 percent of the total (with combined-cycle turbines at 18 percent and simple-cycle turbines and reciprocating engines at 5 percent). Large central station coal plants, located in Montana, Wyoming, and Nevada, represent the region's third largest energy resource comprising about 17 percent of the total. As described below, coal's share of the total will diminish over the next decade through announced retirements.

In contrast to the decline in coal generating capability, the past decade has seen a very rapid development of wind generation. Wind now comprises about 8 percent of the region's electricity supply. This development was prompted by renewable portfolio standards adopted in three of the four Northwest states. It appears, however, that the rapid development of wind is likely to slow down over the next five year period due to the expiration of incentives and low load growth.

The region has a single operating nuclear plant, Columbia Generating Station, which contributes about 3 percent to the energy supply. The existing regional power supply and its capabilities are described in detail in the Council's Generating Resources Database.[4]

[4] The Council's Generating Resource Database can be found at this link: www.nwcouncil.org/energy/powersupply

Figure 9 - 2: Pacific Northwest Electricity Power Supply – Energy Generating Capability



Northwest Generating Capability ~34,750 aMW

Located in Power Act Region or contracted to PNW loads; WECC; In-service, under construction, standby or idle
Includes PacifiCorp WY wind plants
*Other - Geothermal, Petroleum, Solar

Additions and Retirements

Over the past two decades, large thermal resources such as coal and nuclear plants became less desirable to acquire. In part, this was due to their large size, longer development lead times, and other factors such as cost and environmental considerations. Smaller, shorter lead time resources, such as gas-fired turbines, wind, and to some extent solar, which can be scheduled to better match load growth, are now the principal generating technologies considered for resource development. Since the adoption of the Sixth Power Plan in 2010, the region's power system has seen the addition of a variety of resources – although dominated by wind and natural gas – and limited retirements. Figures 9-3 and 9-4 show the energy and capacity additions and retirements over the past decade. Some of the highlights include:

- **Wind power.** Over the past decade, the region has seen significant wind power development. In 2012, the region installed around 2,000 megawatts nameplate capacity – the highest annual acquisition of wind capacity in the region to date. The following year, in part due to the expiration and uncertainty of the future of the Production Tax Credit, there was no major development of new wind resources. In all, roughly 8,700 megawatts of wind capacity has been built in the region since the early 2000s.

- **Natural Gas.** With low natural gas prices and the need for additional flexibility and integration of variable energy resources, the region has seen the addition of a few gas-fired plants. Two of the larger plants are the 300 megawatt Langley Gulch combined cycle power plant installed by Idaho Power in 2012, and the 220 megawatt reciprocating engine gas plant installed by Portland General Electric at the end of 2014.

- **Energy Efficiency.** The region has continued to exceed the Council's power plan annual energy efficiency targets since 2005. From 2010 through 2014, the region achieved 1,500 average megawatts of energy efficiency savings, exceeding the Sixth Plan's 1,200 average-megawatt goal for 2010-2014.

- **Small biomass.** Several small biomass plants have popped up around the region, such as anaerobic digesters on dairy farms and landfill gas power plants on municipal waste projects. While not huge power producers, these small plants often fit into the natural operation cycle and can generate electricity to meet on-site loads or to sell. As renewable resources, these projects qualify as eligible resources to meet many state renewable portfolio standard goals.

- **Hydroelectric power.** The region has been undergoing upgrades to many of its existing hydroelectric turbines resulting in increased efficiency (greater energy output) and adding turbines and new equipment resulting in increased capacity. New small hydropower projects have also been assessed for feasibility in the Pacific Northwest. Snohomish PUD developed its 7.5 megawatt nameplate capacity Youngs Creek project in 2011.

- **Retirements.** Very few plants have been retired over the past five years. Some of the notable retirements include: TransAlta's Big Hanaford combined cycle power plant and Elwha and Condit small hydroelectric dams.

- **Announced retirements**. There have been several announcements of upcoming retirements of coal plants in the region over the next decade. Portland General Electric announced that it will cease coal-fired generation at Boardman in 2020, TransAlta will retire Unit 1 and 2 of its Centralia coal plant in 2020 and 2025, respectively, and PPL Montana announced the permanent retirement of J.E. Corette in late 2015. NV Energy has announced the retirement of the North Valmy coal plant in Nevada, scheduled for 2025. Idaho Power Company co-owns the North Valmy plant.

- **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 generating capability by about ten percent or by about 1,100 average megawatts. 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]

[5] For more information on balancing needs see Chapter 16.

Figure 9 - 3: Generating Additions and Retirements (Installed Capacity)

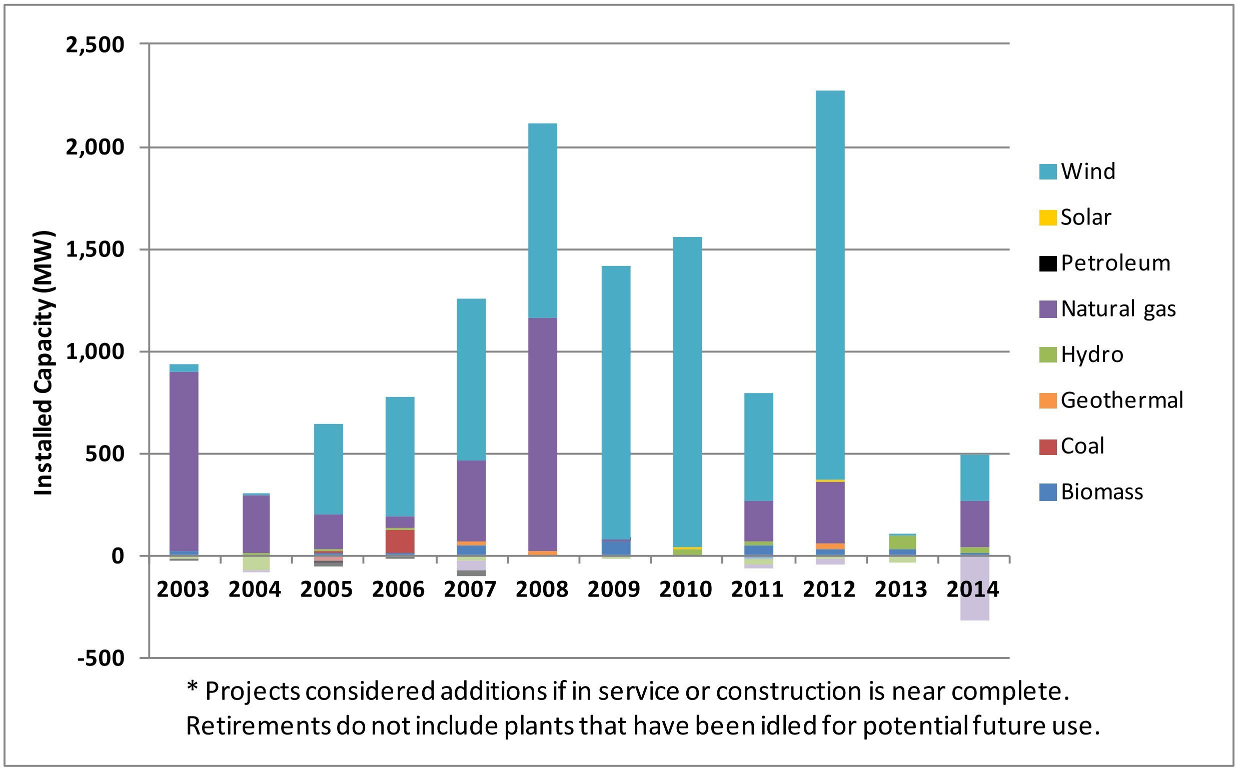
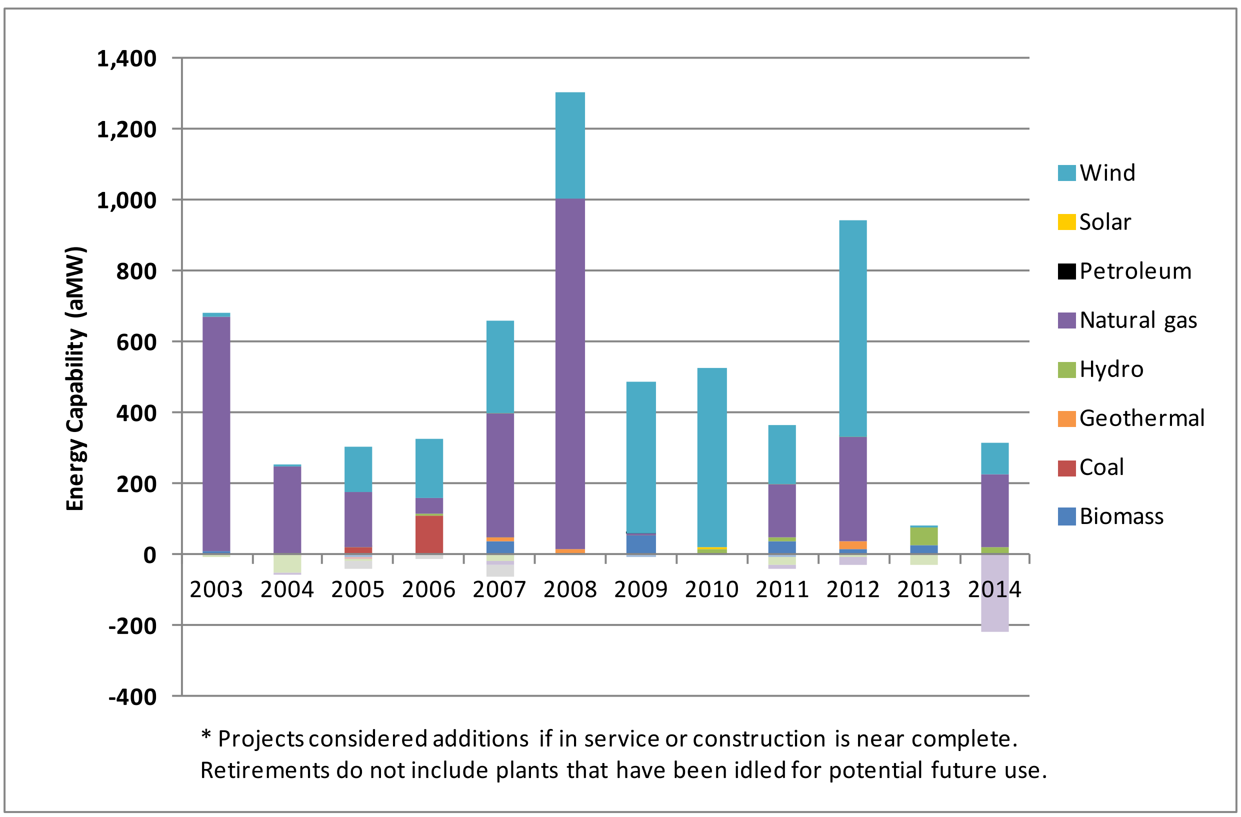


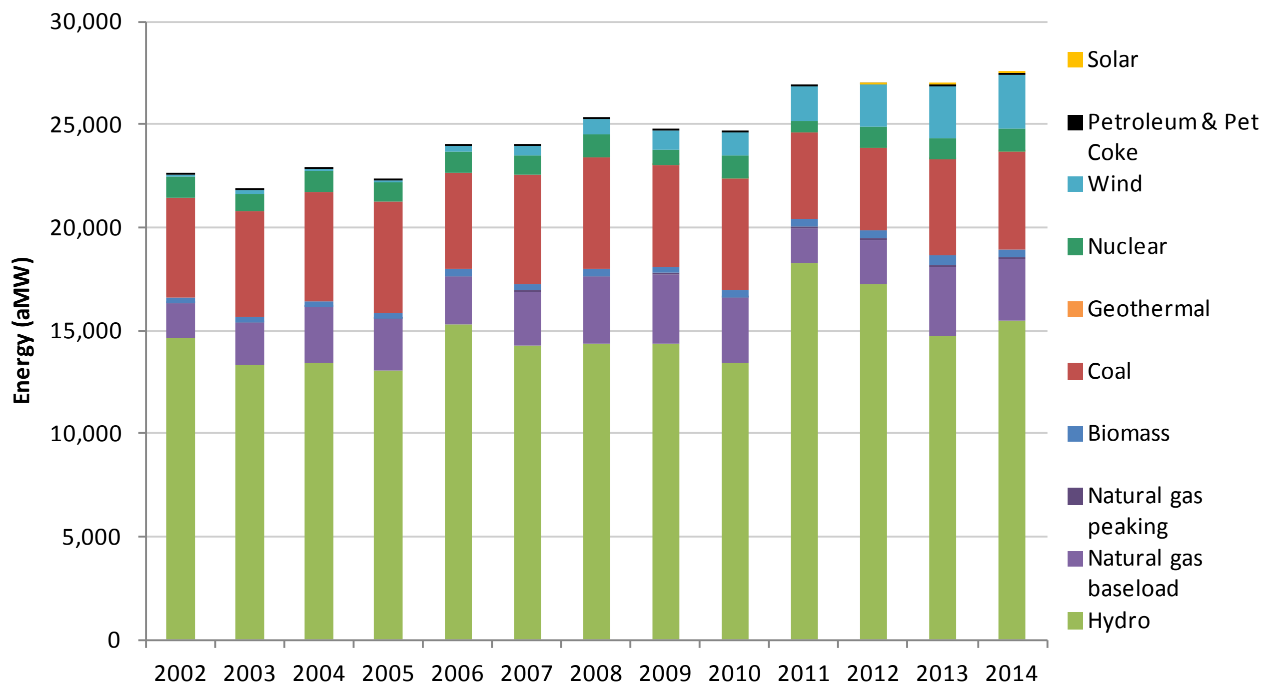
Figure 9 - 4: Generating Additions and Retirements (Energy Capability)



Historical Generation

The Pacific Northwest power system is dominated by its significant hydropower generation. Figure 9 - 5 below shows the historical annual energy production since 2002 by resource type. As illustrated in the figure, while remaining the dominant resource, annual hydroelectric generation varies significantly depending on weather conditions and snowpack. Generation from natural gas power plants is directly correlated to hydroelectric generation; in good water years, less power is dispatched from gas-fired plants and in poor water years, more power is dispatched. Generation from wind resources has made increasing contributions over the past decade.

Figure 9 - 5: Historical Energy Production in the NW since 2002



Data from EIA; Excludes small projects not reporting to EIA. WECC only (excludes E. Montana projects in MRO reliability area)

Expected Resource Dispatch

Through this point in the chapter, the makeup of the region's power supply and how it has been dispatched over the last decade has been discussed. It is also of interest to project how the system might be used in future years. Figures 9 - 6 through 9 - 8 illustrate how various resource types would be dispatched, on average, for the 2017 operating year. The Council's 2014 resource adequacy assessment indicated that the region's power system was expected to continue to provide an adequate supply through 2020 (assuming that energy efficiency measures were acquired as targeted in the Sixth Power Plan). Figure 9 - 6 shows the expected dispatch of all regional resources. On average, the hydroelectric system provides about two-thirds of the energy needs for the region. Coal and natural gas combined provide about 18 percent of the region's electricity and the Columbia Generating Station (nuclear) provides about four percent of the total generation. Renewable resources, namely wind and biomass, contribute about eight percent. The remaining energy, about three percent, is imported from out of region or is produced by in-region merchant generators.

Figure 9 - 6: Expected Annual Energy Dispatch for the Northwest Power Supply in 2017

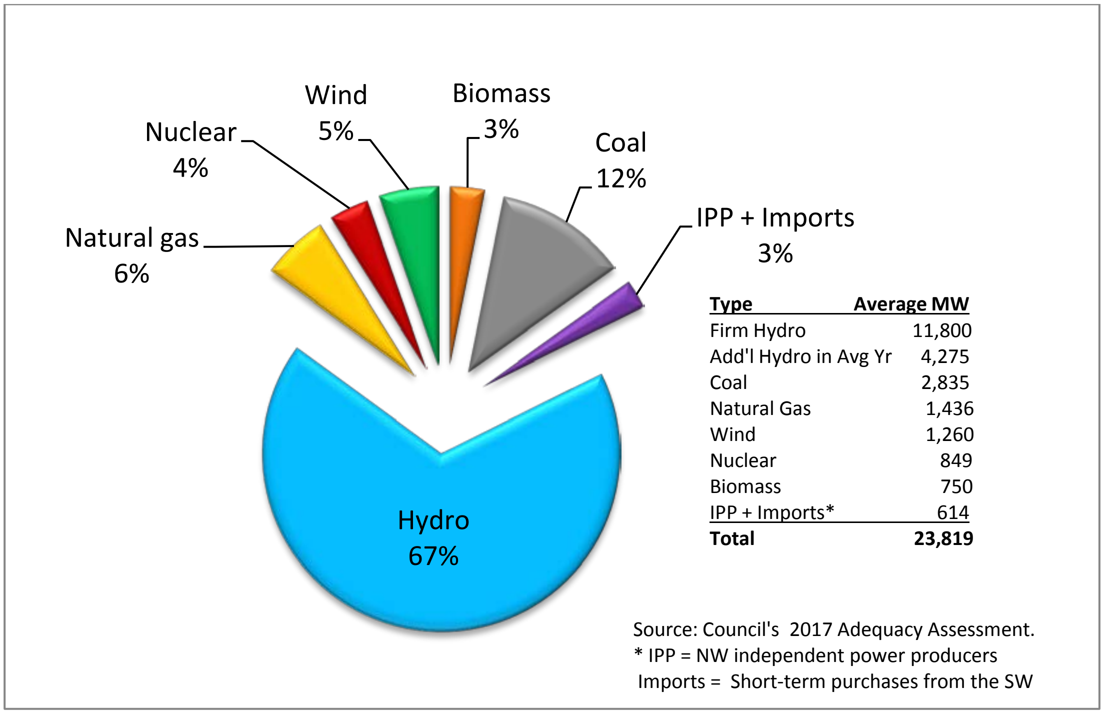


Figure 9 - 7 shows the expected resource dispatch for the federal system. The bulk of federal generation, nearly 90 percent, comes from the federal hydroelectric system. Figure 9 - 8 shows the expected resource dispatch for the non-federal portion of the region's power supply. The non-federal power supply is almost equally split between hydroelectric generation and non-hydroelectric generation. It should be noted that the actual generation production in any future year is dependent on the Columbia River Basin runoff volume –as was illustrated for historical generation in Figure 9 - 5.

Figure 9 - 7: Expected Annual Energy Dispatch for the Federal Power Supply in 2017

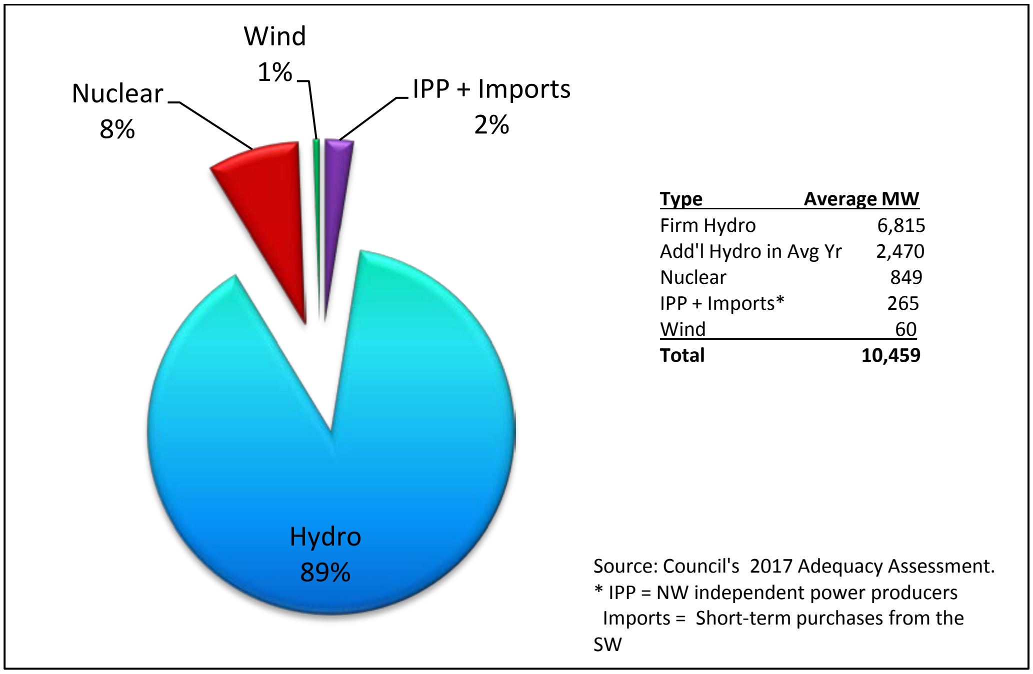
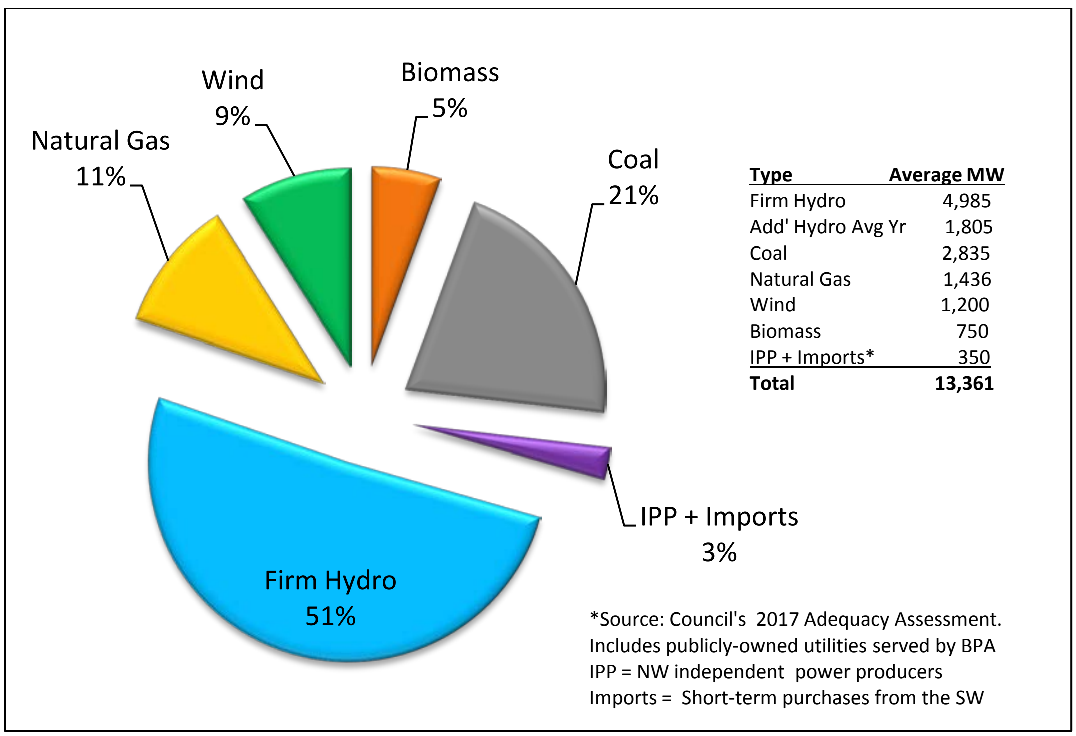


Figure 9 - 8: Annual Energy Dispatch of Non-Federal Generation in 2017



EXISTING GENERATING RESOURCES

The following section details the Pacific Northwest's existing resource base – how it was developed, what its drivers were, and in what quantity. In addition, the environmental effects and regulatory compliance requirements are noted for each resource – for more detail on these see Appendix I, which also contains a discussion of the environmental effects and issues associated with the development of the transmission system. See also Chapter 19, which describes the requirements for how the Council considers information on environmental effects with regard to the existing power supply, including the cost estimates related to compliance with environmental regulations, in crafting the power plan's new resource strategy.

The Hydroelectric System

The Columbia River originates in the Rocky Mountains in Canada, is joined by several major tributaries, including the Snake River, and extends a total of 1,243 miles to the Pacific Ocean. River flows are dominated by the basin's snow pack, which accumulates in the mountains during winter and then melts to produce runoff during spring and summer. The annual average runoff volume, as measured at The Dalles Dam, is 134 million acre-feet but it can range from a low of 78 million acre-feet to a high of 193 million acre-feet.

The Columbia River and its associated tributaries comprise one of the principal economic and environmental resources in the Pacific Northwest. Some 255 Federal and non-Federal dams have been constructed in the basin, making it one of the most highly developed basins in the world. Federal agencies have built 14 major multi-purpose projects on the Columbia and its tributaries, of which four are large storage reservoirs.[6] The total active storage capacity of all the reservoirs in the Columbia River (U.S. and Canada) is about 56 million acre-feet. This represents about 42 percent of the average annual volume runoff as measured at The Dalles. The four large Federal reservoirs have a storage capacity of just over 15 million acre-feet. Total active U.S. storage is a little over 35 million acre-feet, which includes about two million acre-feet of non-treaty storage at the Mica project in Canada. This represents about 63 percent of the basin's total active storage capability. In practice, however, some of the region's active storage is unavailable due to seasonal minimum elevation constraints implemented for various purposes, including fish and wildlife protection.

The low storage-capacity to runoff-volume ratio means that the reservoir system has limited capability to shape river flows to best match seasonal electricity loads. The Pacific Northwest has historically been a winter-peaking region, yet river flows are highest in late spring when electricity load is generally the lowest. Because of this, the region has based its resource acquisition planning on critical hydro conditions, that is, the historical water year[7] with the lowest runoff volume over the winter-peak demand period. Under those conditions, the hydroelectric system produces about

[6] These are the Grand Coulee, Libby, Hungry Horse, and Dworshak dams.

[7] The water year or hydrologic year is normally defined by the USGS from the beginning of October through the end of September and denoted by the calendar year of the final nine months. The water year of the Columbia River system, however, is modeled from the beginning of September (beginning of operation for reservoir refill) through the end of August.

11,600 average megawatts[8] of energy. On average, over all runoff conditions, it produces nearly 16,300 average megawatts of energy, and in the wettest years it can produce about 19,000 average megawatts. For perspective, the 2016 annual average regional load is expected to be in the range of 20,000 to 21,000 average megawatts.

The current U.S. portion of the Columbia River Basin's hydroelectric system has a nameplate capacity of about 33,000 megawatts. Because of limited storage, however, the hydroelectric system cannot sustain that much power production for very long. Again using the critical hydro criterion, analyses show that the hydroelectric system could sustain about 26,000 megawatts over a two-hour period, 24,000 megawatts over a four-hour period and 19,000 megawatts over a ten-hour period. These assessed capacity values are used for resource planning in the same way that the critical-year energy capability (11,600 average megawatts) is used. The assessed capacity values devoted to meeting firm load include the effects (a reduction) of carrying regional within-hour balancing reserves.

The Power Act requires that the Council's power plan and Bonneville's resource acquisition program assure that the region has sufficient generating resources on hand to serve energy load and to accommodate system operations to benefit fish and wildlife. The Act requires the Council to update its fish and wildlife program before revising the power plan, and the amended fish and wildlife program then becomes a part of the power plan. The plan sets forth "a general scheme for implementing conservation measures and developing resources" with "due consideration" for, among other things, "protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival and propagation of anadromous fish."[9] For further detail on these portions of the Act and how the Council is developing the Seventh Power Plan consistent with these requirements, see Chapters 19 and 20.

Since 1980, prior to the implementation of the Council's Fish and Wildlife Program, the hydroelectric system's firm energy generating capability has decreased by about 1,100 average megawatts, which represents almost 10 percent of its current capability. The hydroelectric system's peaking capability devoted to meeting firm load has decreased by over 5,000 megawatts since 1999.[10]

These impacts would definitely affect the adequacy, efficiency, economy, and reliability of the power system if they had been implemented over a short time. However, this has not been the case. Since 1980, the region has periodically amended fish and wildlife related hydroelectric system operations and, in each case, the power system has had time to adapt to these incremental changes. The Council's current assessment[11] indicates that the regional power supply can reliably provide actions specified to benefit fish and wildlife (and absorb the cost of those actions) while maintaining an

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[8] Source: 2014 White Book, Bonneville

[9] Northwest Power Act, Sections 4(e)(2), (3)(F), 4(h)(2)

[10] This decrease is not solely due to fish and wildlife constraints. It also includes operations to carry within-hour balancing reserves. This value is assumed to be consistent with a 10-hour peaking duration. It is not clear how much the peaking capability has declined since 1980 because that year's version of Bonneville's White Book was not found.

[11] See http://www.nwcouncil.org/energy/resource/Adequacy%20Assessment%20Final.doc.

adequate, efficient, economic, and reliable energy supply. See Chapter 20 for more information on the Council's Fish and Wildlife Program.

Coal-fired Power Plants

Following the development of the Columbia River hydroelectric system, coal and nuclear power were viewed as the most economical new sources of electricity. Between 1968 and 1986, 14 coal-fired power units at six sites were brought into service by Northwest utilities – Boardman (Oregon), Centralia (Washington), Colstrip (Montana), J.E. Corette (Montana), Jim Bridger (Wyoming), and North Valmy (Nevada). These large plants can serve about 7,300 megawatts of nameplate capacity, of which about 5,000 megawatts are currently dedicated to Northwest loads. In addition, there are several smaller coal plants in the region that total approximately 200 megawatts in nameplate capacity. Sufficient supplies of low-cost, low-sulfur coal are available from the Powder River Basin (eastern Montana and Wyoming), East Kootenay fields (Southeastern British Columbia), Green River Basin (Southwestern Wyoming), Uinta Basin (northeastern Utah and northwestern Colorado), and extensive deposits in Alberta.

Efforts to reduce carbon dioxide production have resulted in a series of state and Federal environmental regulations requiring modifications and improvements to existing coal-fired power plants. As a result of the incremental cost required to bring the coal plants into compliance with these known and proposed regulations, owners must weigh the economics of continued operation versus early retirement.

In the Pacific Northwest, several coal plants are scheduled for retirement during the Seventh Power Plan's 20-year power planning period. J.E. Corette is scheduled to retire in 2015, Portland General Electric is scheduled to cease coal-fired operation at Boardman in 2020, and Centralia's units one and two will be retired in 2020 and 2025, respectively. The North Valmy coal plant in Nevada, co-owned by Idaho Power, is scheduled to be retired by 2025.

Environmental effects of coal generation span a wide range, from the combustion of fuel to the disposal of waste. The mining of coal itself also produces greenhouse gas emissions, namely methane. Since coal is contaminated by heavy metals, radionuclides, and rare elements, these materials are released into the atmosphere as pollutants during the coal combustion process.[12] In addition, the intake and discharge of the cooling water (which may be contaminated by waste and metals during the cooling process) can affect nearby ecosystems and aquatic life. The disposal of waste from the coal combustion process requires a significant amount of land and, depending on the waste disposal structure, can pollute surface water.

As mentioned previously, there are many existing and proposed federal rulemakings intended to reduce and mitigate environmental impacts of coal generation. While many of the Pacific Northwest coal plants may already be in compliance with some or all of these regulations, it is important to note the rulemakings and the capital and operating costs to comply with them. Many of the rulemakings

[12] See the Third Power Plan, page 721 of Vol II, for a table of heavy metals released from a typical 500 MW coal plant in the PNW.

fall under the Environmental Protection Agency's Clean Air Act and Clean Water Act. The National Ambient Air Quality Standards (NAAQS), Regional Haze rule, Mercury and Air Toxics Standard (MATS), Coal Combustion Residuals rule (CCR), cooling water intake structures rules, effluent guidelines for steam electric power generation, and carbon pollution standards all affect regional coal plants.

See Appendix I for further detail on the environmental effects in the Pacific Northwest associated with the generation of electricity using coal, as well as the existing and proposed regulations to address those effects. That appendix also contains a detailed breakdown of the estimated compliance costs for each coal plant in the region.

Nuclear Power Plants

Coinciding with the development of the region's large coal-fired power plants in the 1980s, regional utilities initiated construction of ten nuclear power plants. Only two, Trojan, in Oregon, and the Columbia Generating Station (CGS) (originally known as Washington Public Power Supply System Nuclear Project number 2 or WNP-2), in Washington, were eventually completed.[13] Two partially completed plants, WNP-1 and WNP-3, were preserved for many years for completion, but they have since been terminated.

Trojan was permanently shut down in 1993, when it was concluded that the cost of a needed steam generator replacement would result in production costs barely competitive with the cost of power from new resources, and was subsequently demolished in 2006. CGS, now the only nuclear power plant in the region, has been upgraded from its original peak capacity and now has an installed nameplate capacity of 1,190 megawatts. In 2012, the Nuclear Regulatory Commission granted a 20-year renewal to CGS's 40-year operating license, now set to expire in 2043. The economics of continued operation of CGS have been questioned by some parties in the region, but this question is outside the scope of the Seventh Power Plan development.

Environmental effects of nuclear generation are focused primarily on water use and spent fuel disposal; the generation of nuclear energy does not lead to the emission of greenhouse gases. Nuclear power plants use a large amount of water for steam production and cooling, which potentially affect nearby ecosystems and aquatic life. In the case of CGS, its withdrawal from the Columbia River represents a small fraction of the overall river flow and would have to increase by six times to trigger EPA's minimum threshold for industrial water intake regulations.[14] Nuclear power is generated through the fission (splitting of atoms) of uranium and the spent fuel is therefore radioactive waste. This waste must be disposed of in long-term storage in an environmentally safe way, often in steel-lined concrete canisters above or below ground.

Existing and proposed federal rulemakings intended to reduce and/or mitigate the environmental impact of nuclear generation are: a series of Fukushima upgrades (ordered by the NRC in response

[13] Trojan was completed in 1976 and CGS in 1984. The Hanford Generating Project operated on steam from the N-reactor, a Hanford Production Reactor, until 1988, when it was shut down upon termination of plutonium production operations at Hanford.
[14] https://www.energy-northwest.com/ourenergyprojects/Columbia/Pages/Environmental-Impact.aspx

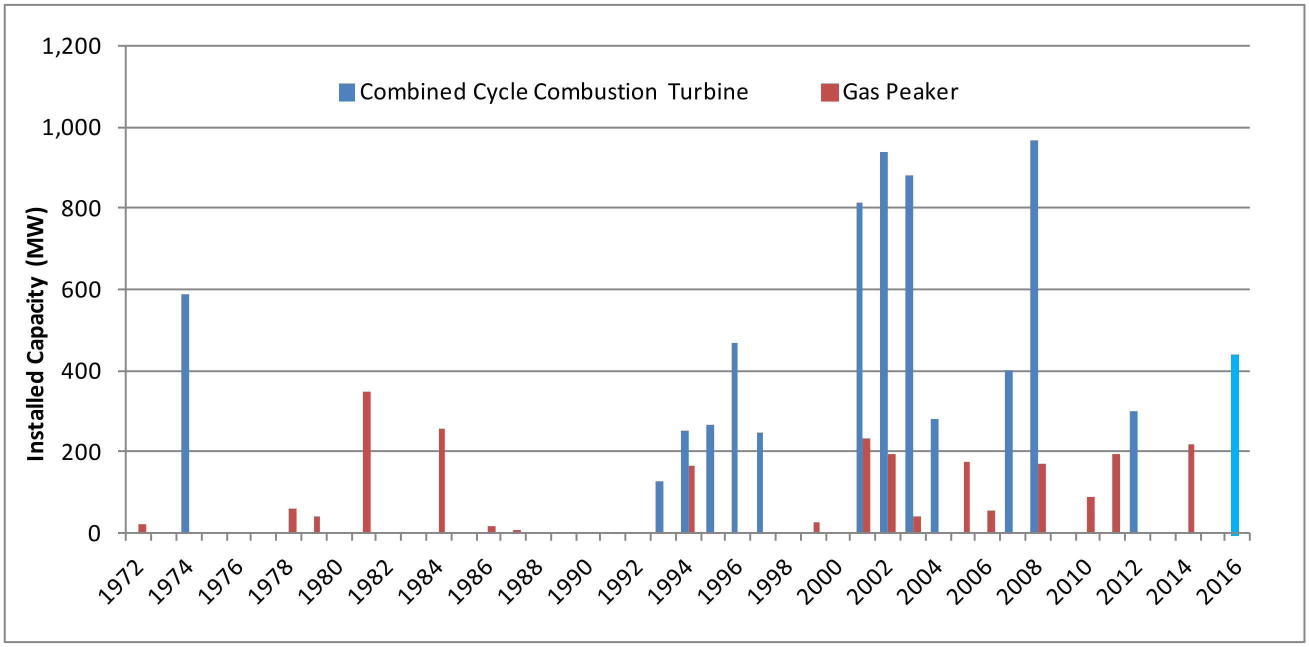
to the Tohoku earthquake in Japan and subsequent Fukushima nuclear plant accident), Containment Protection and Release Reduction rulemakings (CPRR), cooling water intake structure rules, and effluent guidelines. For detailed information on the environmental effects of nuclear generation, on the existing and proposed regulations addressing those effects, and estimates on the costs of compliance, see Appendix I.

Natural Gas-Fired Power Plants

Low natural gas prices and improving combustion turbine technology have made gas-fired combined-cycle power plants a low cost alternative for base load power generation in the Pacific Northwest. Most of these projects consist of one or two combined-cycle combustion turbine units, and many serve modest cogeneration loads. The recent increase in the development of gas peaking plants (simple cycle and reciprocating engine) in the Pacific Northwest and elsewhere can be attributed in part to the need for additional flexibility and efficiency in the power system to supplement and integrate variable energy resources such as wind and solar. Base load gas-fired plants provide about 6,900 megawatts of nameplate capacity and gas-fired peaking plants provide 2,200 megawatts of nameplate capacity in the region.

The first combined cycle power plant developed in the region was Portland General Electric's 600 megawatt Beaver plant in 1974. A few gas peaking plants, primarily frame simple cycle combustion turbines, were constructed in the early 1980's, but it wasn't until the early 1990's that natural gas power plant development picked up. At that time General Electric released its F-class frame unit, a machine with increased reliability and efficiency, and combined with low gas prices, the region saw a shift in development from coal to gas plants. A second wave of gas plant development by independent power producers came in response to the west coast energy crisis in the early 2000's. More recently, plants have been developed in response to power needs identified by investor-owned utilities in their integrated resource planning. Namely, Idaho Power constructed the 300 MW Langley Gulch combined cycle plant in 2012 and Portland General Electric constructed the 220 MW Port Westward II reciprocating engine plant at the end of 2014. Portland General Electric's 440 MW Carty combined cycle combustion plant is scheduled to come online in 2016. Figure 9 - 9 below shows the history of natural gas plant development since the 1970's.

Figure 9 - 9: History of Gas-Fired Plant Development since 1972



Environmental effects of natural gas generation are primarily greenhouse gas emissions from combustion and water use. Natural gas is the cleanest burning of the fossil fuels, with about half of the carbon dioxide emissions of coal and about two-thirds that of distillate fuel oil. In addition to carbon dioxide, nitrogen oxide and volatile organic compounds are also released.

When taking into account the full life cycle of natural gas, beyond simply the combustion of fuel into energy, there are environmental effects from the release or leakage of methane (also known as fugitive emissions) during the extraction, processing, transportation and storage of natural gas. In addition, drilling for natural gas and the construction of pipeline infrastructure have an adverse effect on the land and wildlife.

Existing and proposed federal rulemakings intended to reduce and/or mitigate the environmental impact of natural gas are National Ambient Air Quality Standards (NAAQS), cooling water intake structure rules, effluent guidelines, and potential carbon pollution standards. In addition, the EPA issued proposed rules in August 2015 (published in the Federal Register in September 2015) for reducing methane emissions from new and modified oil and gas facilities by 40 to 45 percent in the next decade. While the quantity of methane released from natural gas extraction and transport is less than the amount of carbon dioxide released, methane as a greenhouse gas is 34 times more potent than carbon dioxide over a 100-year period. For detailed information on the environmental effects, environmental regulations, and estimates of the cost of compliance, *see* Appendix I. Chapter 13 also includes a summary description of these effects and related information, including more sharply focused environmental compliance costs, with regard to the possible development of new gas-fired resources in the region.

Industrial Cogeneration

Cogeneration, or combined heat and power (CHP), plants produce both electricity and thermal or mechanical energy for industrial processes, space conditioning, or hot water. In the Pacific Northwest, there are different types of industrial cogeneration, namely biomass and natural gas plants. Industrial cogeneration in the forest products industry has long been a component of Pacific Northwest electric power generation. These plants include chemical recovery boilers in the pulp and paper industry, and power boilers fired by wood residues, fuel oil, and gas in both the pulp and paper and lumber and wood products sectors. Gas-fired combustion turbines have also been installed as industrial cogeneration units, oftentimes with the waste heat (steam) being used for secondary heating purposes.

Because of mill closures in recent years, and because many industrial cogeneration plants do not sell power offsite or generate power only when fuel costs are favorable, a precise inventory of operating industrial cogeneration plants is difficult to obtain. For these purposes, the known plants have been included in the generating capacity of the primary resource, for example biomass and natural gas. For a detailed breakdown by plant, see the Council's generating projects database.[15]

Environmental effects of cogeneration are the same as those for natural gas and biomass. See Appendix I for details.

Renewable Resources

While wind power has become the dominant renewable resource in the region, biomass has had a regional presence for decades, and geothermal and solar photovoltaic development is on the rise. Emerging resources like offshore wind power and wave/tidal energy are still nascent in the region (more information can be found in Chapter 13).

Evolving Policies and Incentives for Renewable Resources

Many federal and state policies have been established over the past several decades to promote development of renewable resources. In fact, the Pacific Northwest Electric Power Planning and Conservation Act, which created the Council, states in section 839b(e)(1) "the plan shall, as provided in this paragraph, give priority to resources which the Council determines to be cost-effective. Priority shall be given: first, to conservation; second, to renewable resources."

The adoption of the federal Production Tax Credit (PTC) and Business Energy Investment Tax Credit (ITC) has significantly contributed to the rapid development of renewable generation. Both incentives expired and renewed several times in the past decade, limiting their effectiveness in recent years due to last minute, retroactive, renewals. In late 2014, the PTC was renewed through the calendar year 2014, but very few projects nationally were able to take advantage of it. In

[15] Council's generating projects database can be found on the Power Supply webpage of the Council's website - http://www.nwcouncil.org/energy/powersupply/

December 2015, both the PTC and ITC were amended once more as part of the Consolidated Appropriations Act.

The PTC is a production-based corporate income tax credit in which the owner of a qualifying project receives an incentive based on the amount that the project generates (per kilowatt hour) and sells, for the first ten years of operation. The incentive begins to phase down (a percentage reduction in the credit amount) for wind facilities beginning construction after 2016 and expires after 2019, and expires at the end of 2016 for all other eligible technologies. In contrast to the PTC, the ITC is a front-loaded incentive based on the initial capital expenditures of the project. The ITC is a 30 percent federal tax credit for solar systems on residential and commercial properties that remains in effect through 2019, at which point it phases down to 10 percent in 2022 for the foreseeable future.[16] Developers of wind projects are able to claim the ITC in lieu of the PTC, however the credit is phased down from 30% in 2016 to zero in 2020.

The adoption of state renewable portfolio standards (RPS) in Washington, Oregon, and Montana in the mid-2000s has also led to a significant increase in renewable resource development over the past decade. While Idaho does not have an RPS, its Idaho Energy Plan encourages the development of cost-effective local renewable resources, further contributing to the renewable boom of recent years. See Appendix I for a more detailed discussion of state RPS.

In Oregon, the Business Energy Tax Credit (BETC), which "is a nonrefundable credit against personal and corporate income taxes based on the 'certified cost' of certain investments in energy conservation, recycling, renewable energy resources, or reduced use of polluting transportation fuels," expired on July 1, 2014. Originally enacted in 1979, the BETC was an effort to encourage alternative energy development.

Wind

The first utility-scale wind projects in the region came online in 1998. With the adoption of the state renewable portfolio standards (RPS), wind development ramped up significantly, peaking in 2012 with 2,000 megawatts of installed capacity in the region. Uncertainty over the repeated expiration and renewal of the Production Tax Credit (PTC) has led to bursts and lulls in wind development. As an alternative to the PTC, wind developers were also able to take advantage of the Investment Tax Credit (ITC). The effect of both RPS and PTC/ITC drivers can be seen in Figure 9 - 10 below. In total, there is about 8,700 megawatts of wind power nameplate capacity installed in the region, including the PacifiCorp wind projects located in Wyoming.[17] Currently, about one-third of this wind power capacity is under long-term power purchase contracts with out-of-region parties. Figure 9 - 11 shows the cumulative wind capacity developed in the region by load serving entity, based on known

[16] The ITC can also be used at 30% for fuel cells and small wind (less than 100kW), and 10% for specific geothermal systems, microturbines, and combined heat and power projects – both credits expiring at the end of 2016. Geothermal electric maintains a 10% credit indefinitely. See the Database of State Incentives for Renewables and Efficiency (DSIRE) for more information - http://www.dsireusa.org/.

[17] The Council includes PacifiCorp Wyoming wind projects in its regional total because they are eligible to meet some renewable portfolio standard requirements in Oregon and Washington.

power purchase agreements. As states are on track to meet their near-term RPS goals, the pace of wind power development has slowed in recent years.

The diversity of the region's wind resource has been a topic of discussion, as the majority of the Pacific Northwest wind power is located in the Columbia River Gorge and along the Snake River in Idaho. In fact, as of the end of 2014, over half (4,782 megawatts[18]) of the installed wind capacity in the region was located within the Bonneville Power Administration balancing authority. On occasion, this has led to periods where wind power has been curtailed within a balancing authority when there has been an excess of wind and hydropower on the system. Central Montana is an excellent wind resource area that due primarily to transmission limitations remains mostly undeveloped to date – see Chapter 13 for development opportunities through transmission expansion.

Environmental effects of wind power generation are primarily limited to land use and wildlife interference, because there are no greenhouse gas emissions related to the generation of power itself. Project siting and licensing mitigates much of the land and wildlife impacts due to the requirement of environmental impact statements (EIS). While wind farms use a significant amount of land in total area, on average 85 acres per megawatt,[19] much of that land is either undisturbed by the development or multi-purposed. Wildlife interference occurs in two ways: direct mortality due to collisions with the wind turbines and indirect impacts to wildlife due to the loss of habitat in which the wind project resides. The primary wildlife impacted by wind projects in the Pacific Northwest are songbirds, migratory birds, raptors, and bats.

The Bald Eagle and Golden Eagle Protection Act (BGEPA) and Migratory Bird Treaty Act (MBTA) make it a violation of federal laws to kill, or "take," an array of bird species and therefore these laws impose regulations restricting the take of certain avian species. For more information, see Appendix I as well as Chapter 13 for a discussion of wind resource from the perspective of potential new resource additions to the Pacific Northwest's power system.

[18] http://transmission.bpa.gov/business/operations/wind/WIND_InstalledCapacity_PLOT.pdf
[19] http://www.aweo.org/windarea.html; http://www.nrel.gov/docs/fy09osti/45834.pdf

Figure 9 - 10: Wind Capacity Development in the Pacific NW since 1998 (Nameplate)

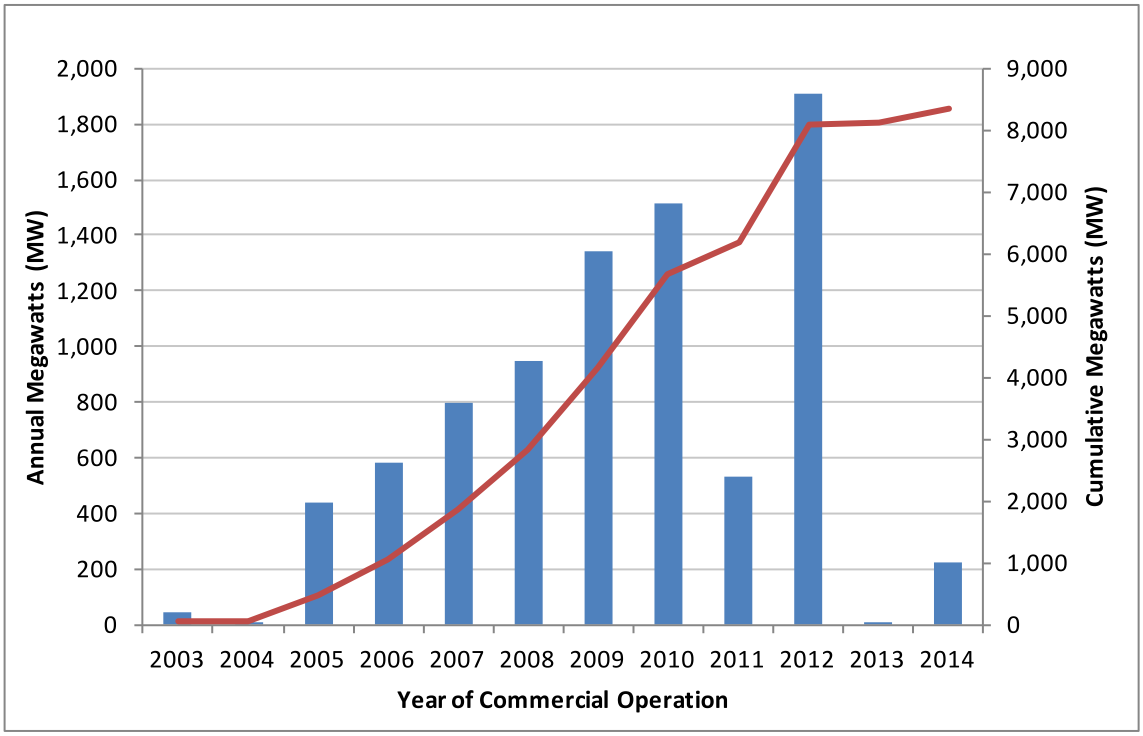
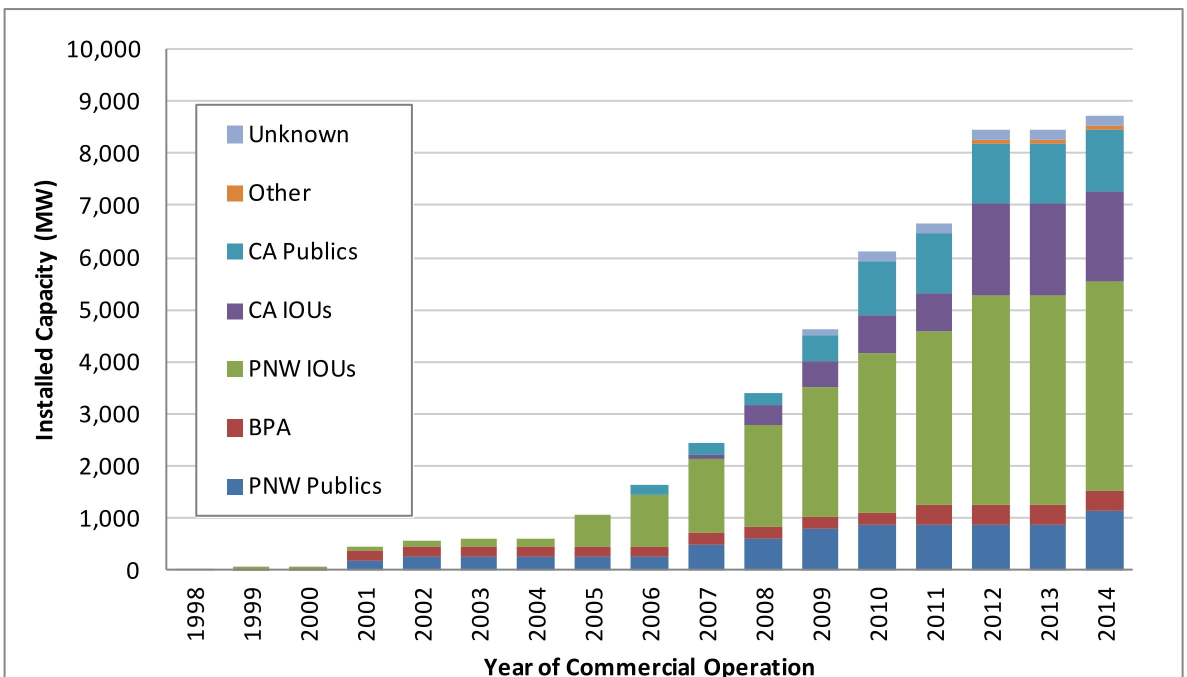


Figure 9 - 11: Wind Capacity by Load Serving Entity (Nameplate)



Located in Pacific Northwest, including PacifiCorp WY projects and NorthWestern MT projects; based on publically available information and power purchase agreements

Solar

In addition to being an eligible resource to meet state RPS, solar photovoltaic (PV) development has been driven by its rapidly decreasing capital costs and the federal and state incentives, namely the Investment Tax Credit (ITC).

Over the past decade, utility-scale solar PV power plants have been developed in growing quantities in the lucrative solar resource areas of the desert southwest. As module and inverter technologies have improved, costs have come down significantly and the Pacific Northwest is beginning to see development of its own. Outback Solar, in Lake County, Oregon, is currently the largest PV project in service in the region at five megawatts AC nameplate capacity. Several projects ranging from 10 megawatts to 80 megawatts, totaling 320 megawatts in Southern Idaho and Eastern Oregon are in development and projected to come online by the end of 2016.

Distributed solar PV energy, often constructed on residential and commercial rooftops with energy consumed directly by the end-user, has been a growing contribution to demand-side resources. State and utility incentives have contributed to the increasing presence of distributed PV in the Northwest, along with social and economic drivers. The Council estimates that by the end of 2015 roof-top solar will contribute about 21 average megawatts of energy and reduce system peak loads by about 56 megawatts.[20]

There are no concentrating solar power (CSP) projects in service or planned for the Pacific Northwest at this time. This type of solar resource has a higher cost per kilowatt than PV, although it has the potential of being a firm resource alternative with the addition of thermal storage.

Environmental effects of solar PV generation are mainly limited to land use and interference with wildlife. Energy production from solar PV plants does not contribute to the release of greenhouse gases. Much of the land and wildlife effects are mitigated during the siting and licensing of power plants. The few CSP projects in service in the desert Southwest and California have encountered issues with high avian and bat mortality directly related to the solar flux produced from the mirrors. For additional detailed information, see Appendix I and Chapter 13.

Biomass

Biomass includes a variety of fuels, including pulp and paper, woody residues (forest, logging, and mill residues), landfill gas, municipal solid waste, animal waste, and wastewater treatment plant digester gas.

There is about 1,000 megawatts of installed biomass nameplate capacity in the Pacific Northwest. In recent years, there have been several small (on average three megawatts) animal waste and landfill gas plants developed on existing dairy farms and landfill operations. With the economic recession in the late 2000's, several of the region's paper and textile plants have shut down, reducing the supply of pulping liquor for pulp and paper biomass plants.

[20] See Appendix E for more information on roof-top solar development.

Environmental effects of biomass generation include land use, water, and air quality. Biomass generation uses similar technology to coal and natural gas and therefore is subject to emissions arising from the production process; however, in general biomass emits fewer pollutants than its fossil fuel counterparts. The primary air emissions caused by biomass combustion include nitrogen oxides, sulfur dioxide, carbon monoxide, mercury, lead, volatile organic compounds, particulate matter, carbon dioxide, and dioxins.[21] Biomass generation can be considered a carbon dioxide reducing resource only if re-plantation of the spent fuel occurs (e.g. woody residues). Most existing biomass projects in the region are fueled by already spent resources rather than resources grown for the purpose of energy production, for example animal waste, woody residues, and municipal garbage, and therefore the impact to land and water use to supply the fuel is minimal as it already exists. Depending on the type of technology and fuel used in the power production, there are greenhouse gas emissions and water quality issues associated with biomass. Cooling water can affect nearby land and water sources, depending on where/how it is used. If a closed-loop system is utilized by the power plant, there are fewer impacts to nearby water sources than a once-through or open loop cooling system. *See* Appendix I for further detail on environmental effects and associated environmental regulations and compliance actions.

Geothermal

While there is significant geothermal resource in the Pacific Northwest, especially Southern Oregon and Idaho, there have only been a few projects developed to-date. Most recently, U.S. Geothermal's Neal Hot Springs – a 28.5 megawatt plant in Oregon – came online, bringing the total conventional geothermal installed nameplate capacity in the Pacific Northwest to 40 megawatts. A small geothermal power plant (three megawatts), Paisley Geothermal, is currently under construction in Southern Oregon by Surprise Valley Electric Coop. Demonstration projects for enhanced (engineered) geothermal systems are being developed at Newberry Crater, Oregon. Enhanced geothermal resources have a large potential to be a viable, base loaded energy alternative in the long-run if successful.

Environmental effects of geothermal generation are land and wildlife disturbances, air and water quantity and quality. Much like wind and solar, prospective geothermal power plants must undergo extensive environmental impact reviews that mitigate many land and wildlife impacts. While geothermal plants can take up to several hundreds of acres of land during development, much of that land can be reclaimed and repurposed once construction is complete. Air and water effects depend largely on the type of technology and open/closed loop cycle utilized by the power plant. There are few emissions from binary, closed-loop geothermal power plants as the water and air vapors are re-injected into the production cycle. Open-loop cycle plants emit primarily carbon dioxide and some methane, although it is at an amount that is equivalent to 30 percent of a conventional coal plant. *See* Appendix I for further details.

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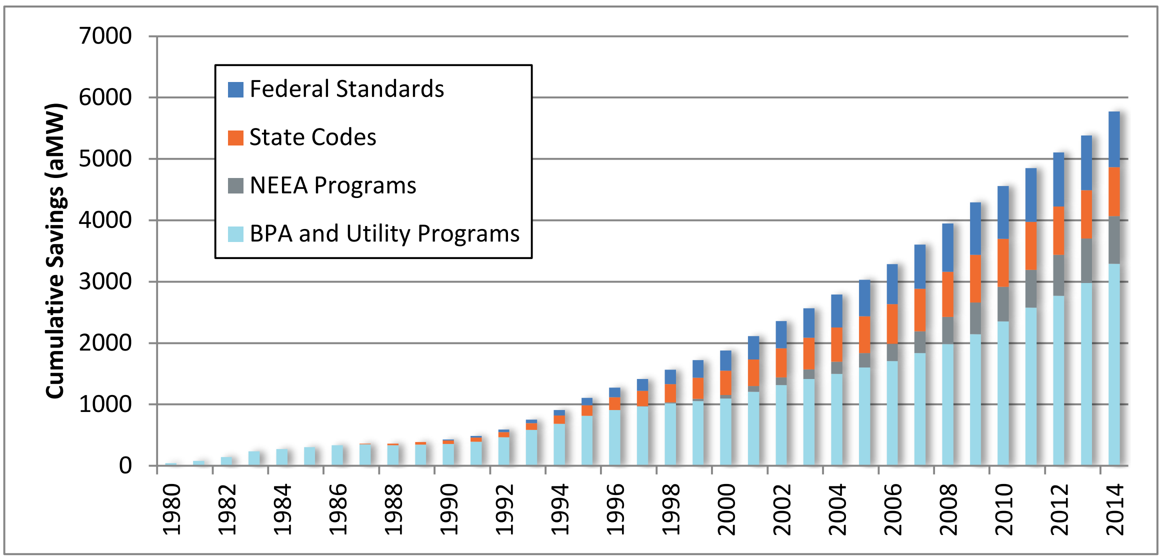
[21] http://teeic.indianaffairs.gov/er/biomass/impact/op/index.htm.

CONSERVATION

Conservation is the first-priority electric power resource in the Northwest Power Act, where it is defined as "any reduction in electric power consumption as a result of increases in the efficiency of energy use, production, or distribution." Since the passage of the Act in 1980, the region—through utility programs, market transformation efforts, and federal and state codes—has achieved nearly 5,800 average megawatts of energy savings.[22] Figure 9 - 12 shows cumulative conservation achievements since 1980. Note this figure does not include market-induced savings that have occurred outside the programs.[23] These achievements are equivalent to the annual firm output of the six largest hydroelectric projects in the region.

Figure 9 - 12: Cumulative Regional Savings Since 1980



Since 1980, conservation has met 57 percent of the region's load growth and has become the second largest resource for the region behind hydroelectric power. This level of conservation is equivalent to nearly 50 billion kilowatt-hours, with a retail value to consumers of over $3.73 billion. These accomplishments have required perseverance, commitment, fresh thinking, and hard work.

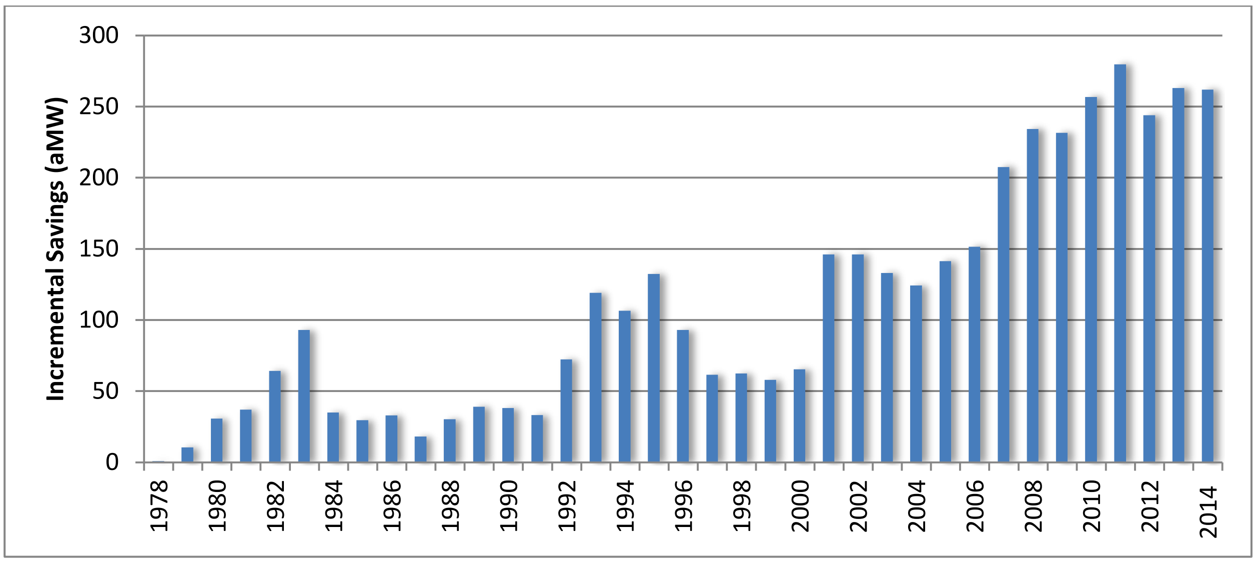
The amount of conservation over the years has varied. Figure 9 - 13 below shows the incremental savings for energy-efficiency programs—including Bonneville, utility, and Northwest Energy Efficiency Alliance programs—between 1978 and 2014. In the late 1970s and early 1980s, the region was in need of electricity, and conservation efforts were accelerated. In the early to middle 1980s, the region was in a period of surplus capacity, and conservation efforts were slowed. In the

[22] Findings are from the Regional Technical Forum's 2014 Regional Conservation Progress Report.
[23] See http://www.bpa.gov/EE/Utility/research-archive/Pages/Momentum%20Savings.aspx for more information.

early 1990s, there was again a need for resources, and the region responded once again by increasing conservation efforts. In the mid-1990s, conservation is again being slowed, as utilities see an uncertain future, and inexpensive energy is abundant in the West Coast market. All of that changed again with the west coast energy crisis in the early 2000s when programs once again increased their conservation efforts.

Significant investment in conservation as a resource continued through the Sixth Power Plan. Between 2010 and 2014, the region captured approximately 1,500 average megawatts of conservation. The vast majority of savings came from lighting projects and other significant contributors included residential and commercial lighting and HVAC projects, residential consumer electronics, and whole building projects across sectors. The total program investment during this period was over $2.5 billion.[24]

Figure 9 - 13: Incremental Savings from Bonneville, Utility, and NEEA Programs*



*Excluding codes and standards.

[24] Regional Technical Forum 2014 Regional Conservation Progress Report.

DEMAND RESPONSE

Demand response, as a means to reduce peak demand, has been used only sporadically throughout the region. Customer participation and utility needs change from year to year. Table 9 - 1 is a snapshot of some of the region's recent demand response programs, by seasonal availability, as reported in utility Integrated Resource Plans (IRPs). The results in Table 9 - 1 do not include current and recent pilot programs.

Table 9 - 1: Demand Response in the Pacific Northwest

System Operator	Program Types	Demand Response in MW (Winter/Summer)	Source
Idaho Power	Flex Peak, Irrigation, Air-Conditioning	0/390	Idaho Power 2015 Draft IRP
PacifiCorp	Irrigation, Curtailable Load Tariff*	149/319	PacifiCorp 2015 IRP
Portland General Electric	Time-Of-Use Pricing, Curtailable Load Tariff	28/0	Portland General Electric 2013 IRP
Bonneville Power Administration	Curtailable Load Tariff, Load Aggregator	60/30**	Discussion with BPA***

*The 149 MW Curtailable Tariff provides benefit for PacifiCorp's Idaho and Utah customers, so some of this might be credited to out-of region loads.

**The values listed in the table are the bottom of a range available, 60-145 MW in the winter and 30-100 MW in the summer. These values are dependent on the contract renewal which is based on projected system need. These values were current as of the draft Seventh Power Plan; however due to changes to BPA load, the existing DR estimates are in flux.

***On 7/8/2015, Council Staff discussed existing DR resources with John Wellschlager and Frank Brown from Bonneville.

In the last few years, demand response demonstration pilot programs have been implemented broadly throughout the region by Bonneville and by public and investor-owned utilities. Demand response can not only be used to decrease loads during peak hours but can also be used to increase load during light load hours when wind generation is unexpectedly high. These pilot programs, which are discussed more in Chapter 14, include exploration of demand response as a tool to provide balancing services for variable energy resources.

Demand response programs might also be able to defer new transmission or distribution investments, facilitate energy storage in flexible end-use loads, and provide dispatchable voltage control. These pilot programs have been conducted in the residential, agricultural, commercial and industrial sectors.